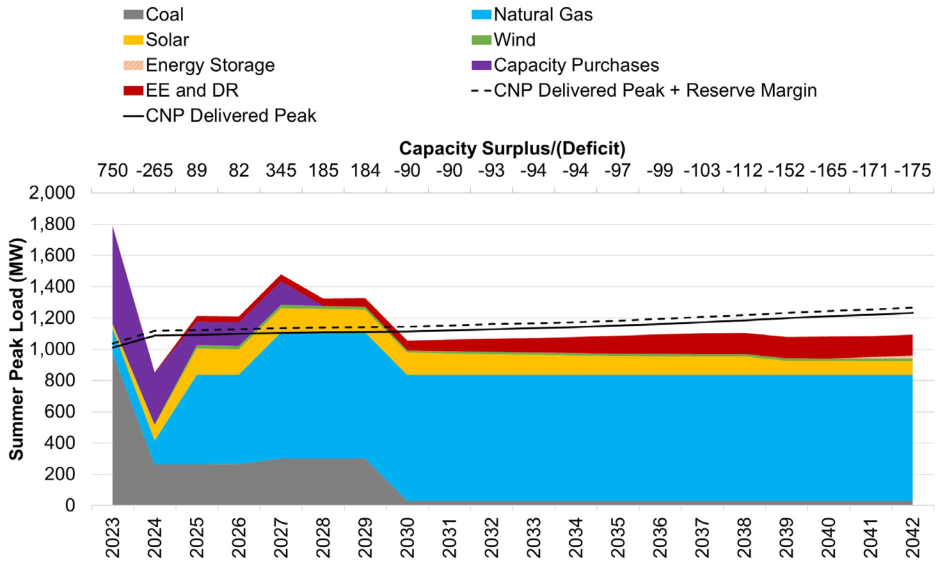
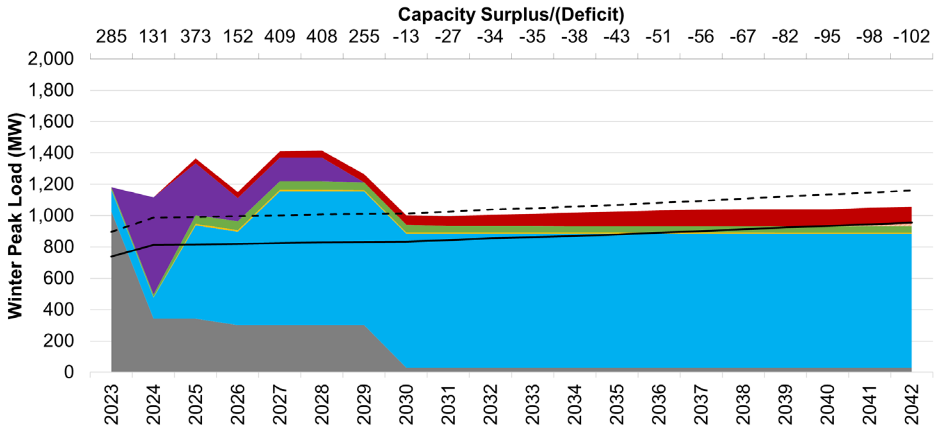
Market Driven Innovation Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- Additional storage in 2032 and 2040s

Balance of Loads and Resources

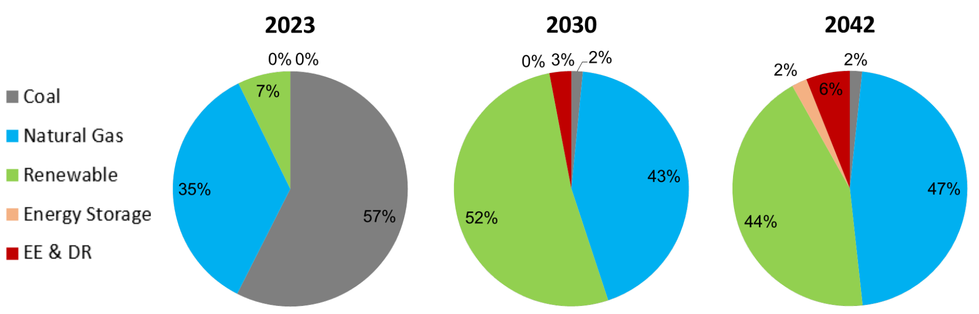




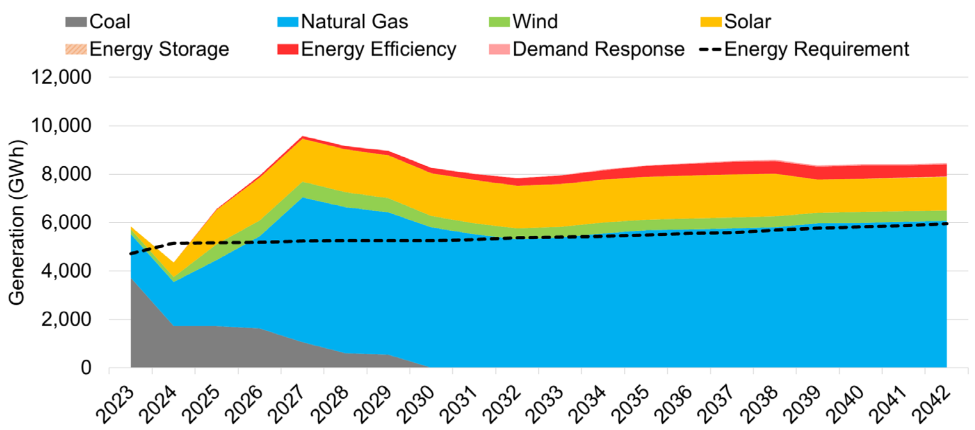
Market Driven Innovation Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- Additional storage in 2032 and 2040s

Installed Capacity



Energy Generation Mix

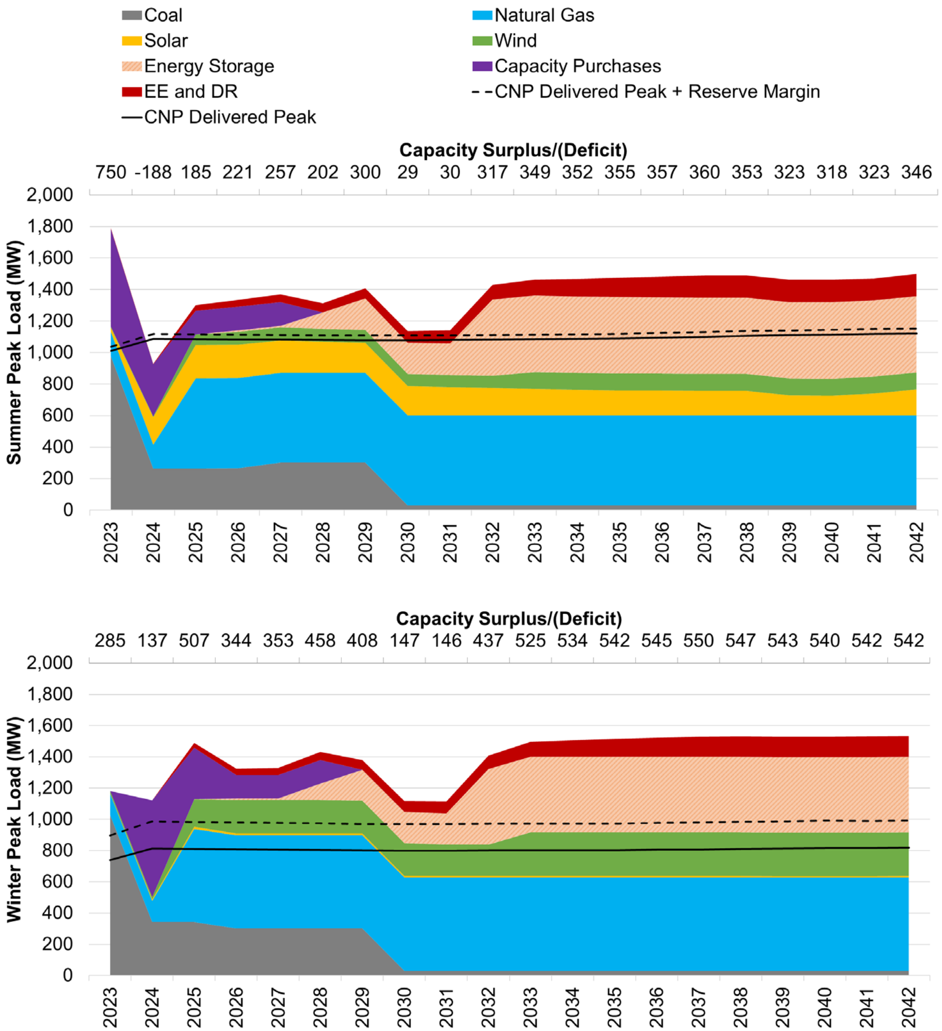


High Regulatory Portfolio Selection

CenterPoint Energy

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- High renewable additions
  - Wind and solar additions throughout study period
  - Solar + Storage
  - Long Duration Storage

Balance of Loads and Resources



High Regulatory Portfolio Selection

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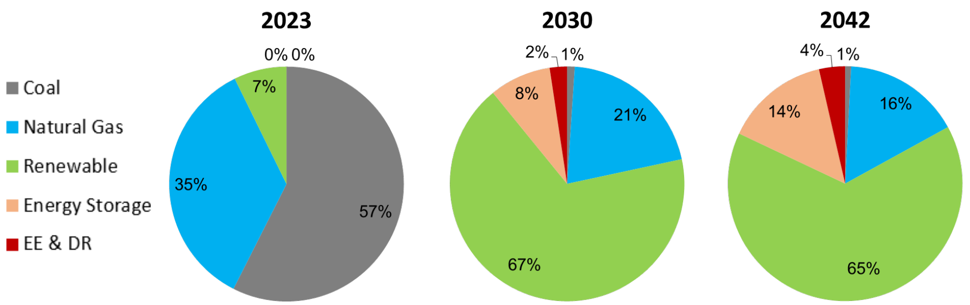
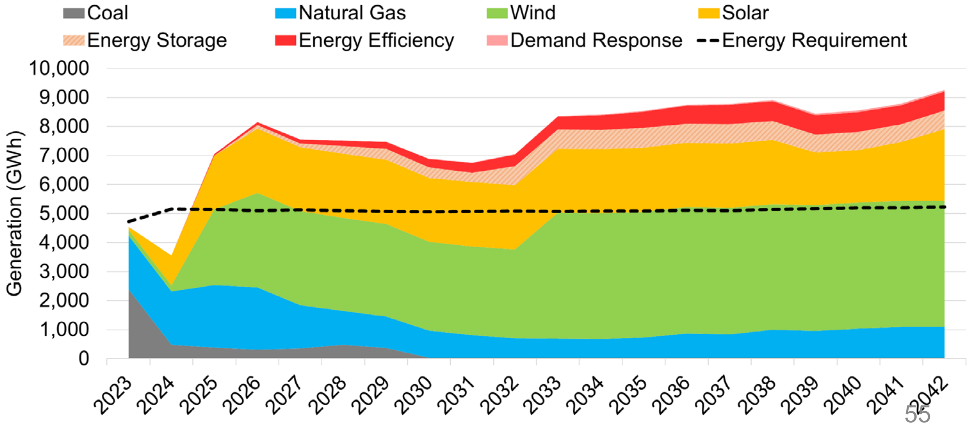
  - Long Duration Storage

Installed Capacity



Energy Generation Mix

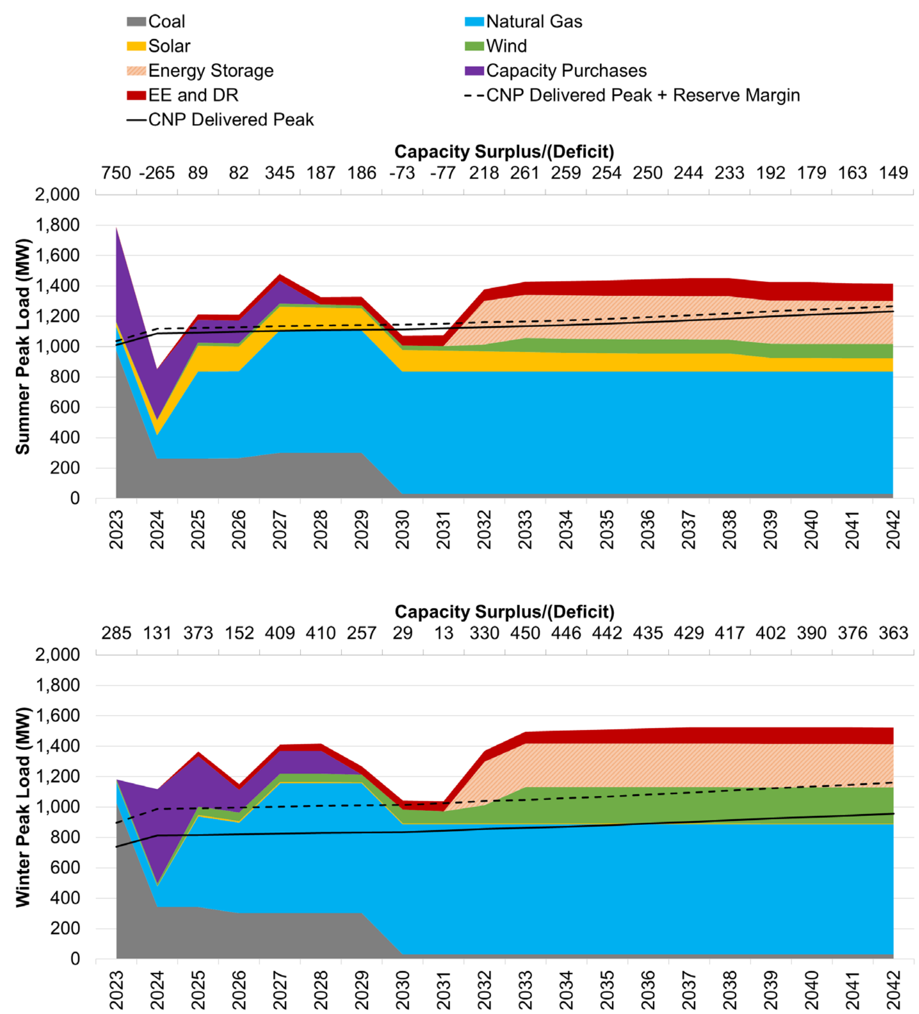


Decarbonization/Electrification Portfolio Selection

CenterPoint Energy

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- Wind in the 2030s
- Long Duration Storage

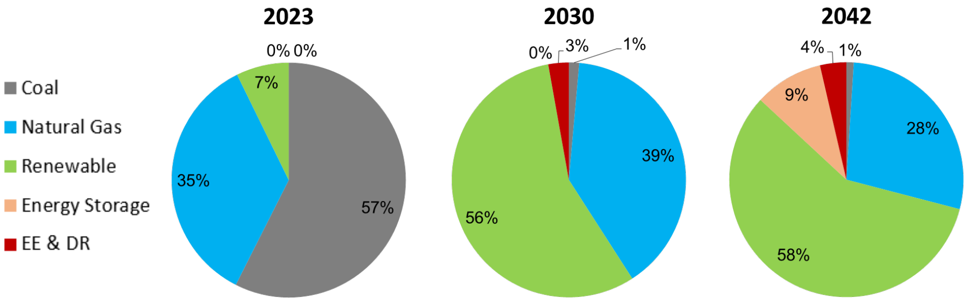
Balance of Loads and Resources



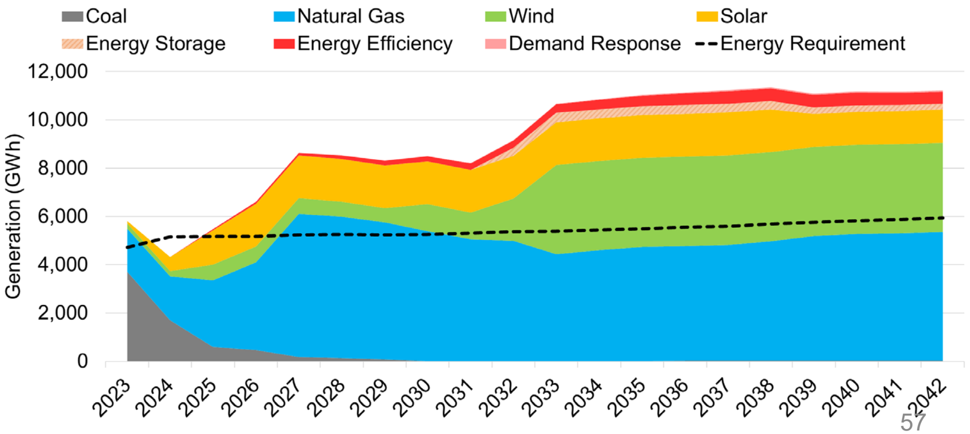
Decarbonization/Electrification Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- Wind in the 2030s
- Long Duration Storage

Installed Capacity



Energy Generation Mix



Draft Deterministic Portfolio Results

Drew Burczyk
Consultant, Resource Planning & Market Assessments
1898 & Co.

Draft Deterministic Portfolios

CenterPoint Energy

Year	Reference Case	BAU	Replace Culley With Storage	Convert Culley to Natural Gas	High Renewables & Storage by 2035	J-Class CCGT	F-Class CT	No AB Brown CCGT Conversion
2024	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Continue FB Culley 3 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)
2026				Covert FB Culley 2 & 3 to Natural Gas				
2027	CCGT Conversion							
2028								
2029	Retire FB Culley 3		Retire FB Culley 3			Retire FB Culley 3	Retire FB Culley 3	Retire FB Culley 3
2030			Storage (300MW)			1x1 J CC UF	1 x F CT	Storage (150MW)
2031								
2032		Wind North (100MW) Long Duration Storage (300MW)		Wind North (200MW)	Wind North (400MW) Long Duration Storage (300MW)		Wind North (200MW) Long Duration Storage (300MW)	Wind North (200MW)
2033	Wind North (600MW)	Wind North (600MW)		Wind North (600MW)	Wind North (600MW)	Wind North (600MW)	Wind North (600MW)	Wind North (600MW)
2034					Retire FB Culley 3			
2042								Storage (10MW)
NPV ($M)								
% Difference From Reference Case								

Note: CEI South's latest RFP only resulted in 2 bids for wind projects. As other utilities pursue wind projects it may become increasingly difficult to execute on wind heavy portfolios if there are not enough viable projects to meet demand.

Draft Deterministic Portfolios – EE & DR

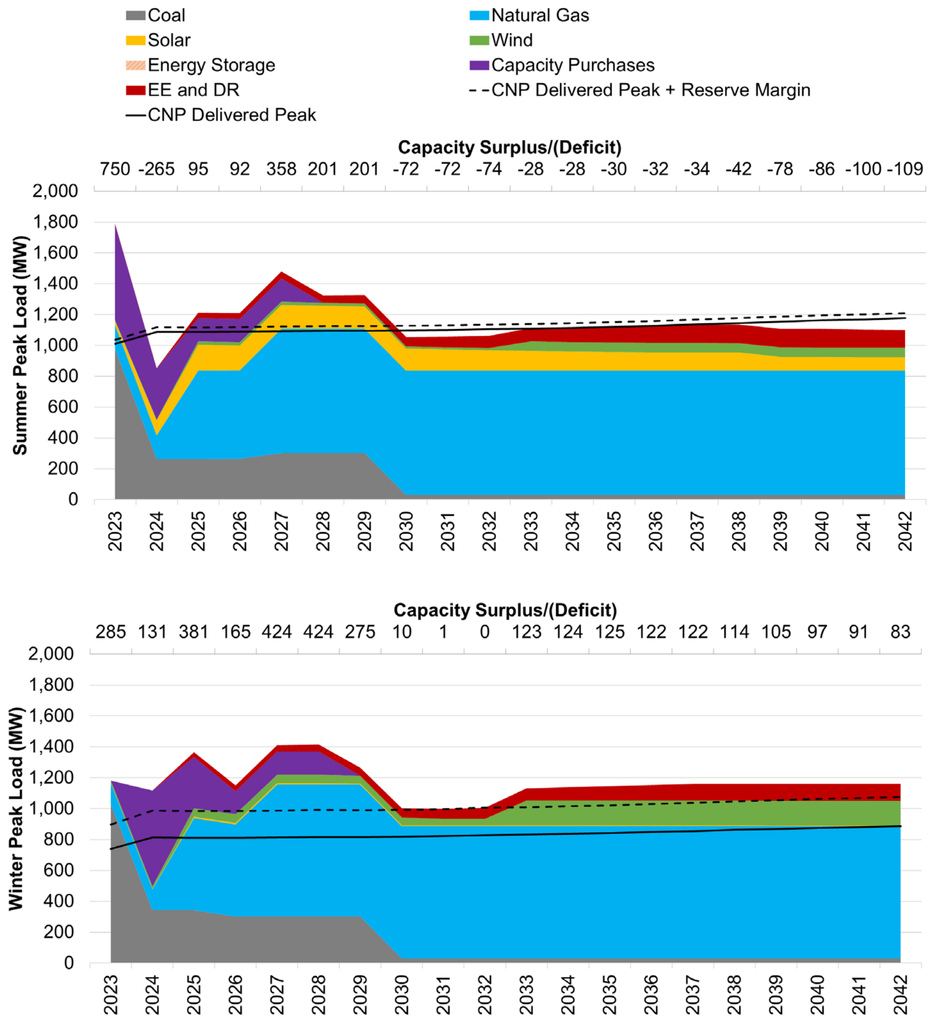
	Reference Case	BAU	Replace Culley With Storage	Convert Culley to Natural Gas	High Renewables & Storage by 2035	J-Class CCGT	F-Class CT	No AB Brown 7 Option
Vintage 1 2025 - 2027	DR Legacy - 2023	DR Legacy - 2023	DR Legacy - 2023	DR Legacy - 2023	DR Legacy - 2023	DR Legacy - 2023	DR Legacy - 2023	DR Legacy - 2023
	DR Industrial	DR Industrial	DR Industrial	DR Industrial	DR Industrial	DR Industrial	DR Industrial	DR Industrial
	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced
	HER	HER	HER	HER	HER	HER	HER	HER
	IQW	IQW	IQW	IQW	IQW	IQW	IQW	IQW
Vintage 2 2028 - 2030	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced
	IQW	HER	HER	HER	HER	IQW	HER	HER
		IQW	IQW	IQW	IQW		IQW	IQW
Vintage 3 2031 - 2042	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced	C&I Enhanced
	DR CI Rates	DR CI Rates	DR CI Rates	DR CI Rates	DR CI Rates	DR CI Rates	DR CI Rates	DR CI Rates
	IQW	IQW	IQW	IQW	IQW	IQW	IQW	IQW
			HER					
			Residential Low & Medium					

IQW = Income Qualified Weatherization
HER = Home Energy Reports
C&I = Commercial & Industrial

Reference Case Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- EE & DR
- Wind in 2033

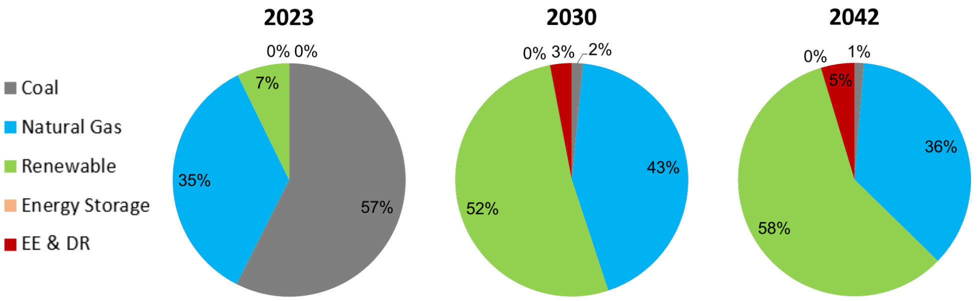
Balance of Loads and Resources



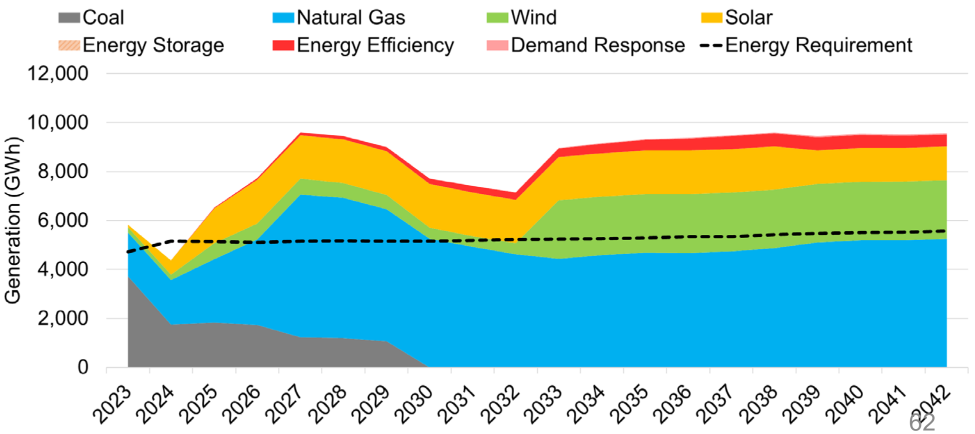
Reference Case Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- EE & DR
- Wind in 2033

Installed Capacity



Energy Generation Mix

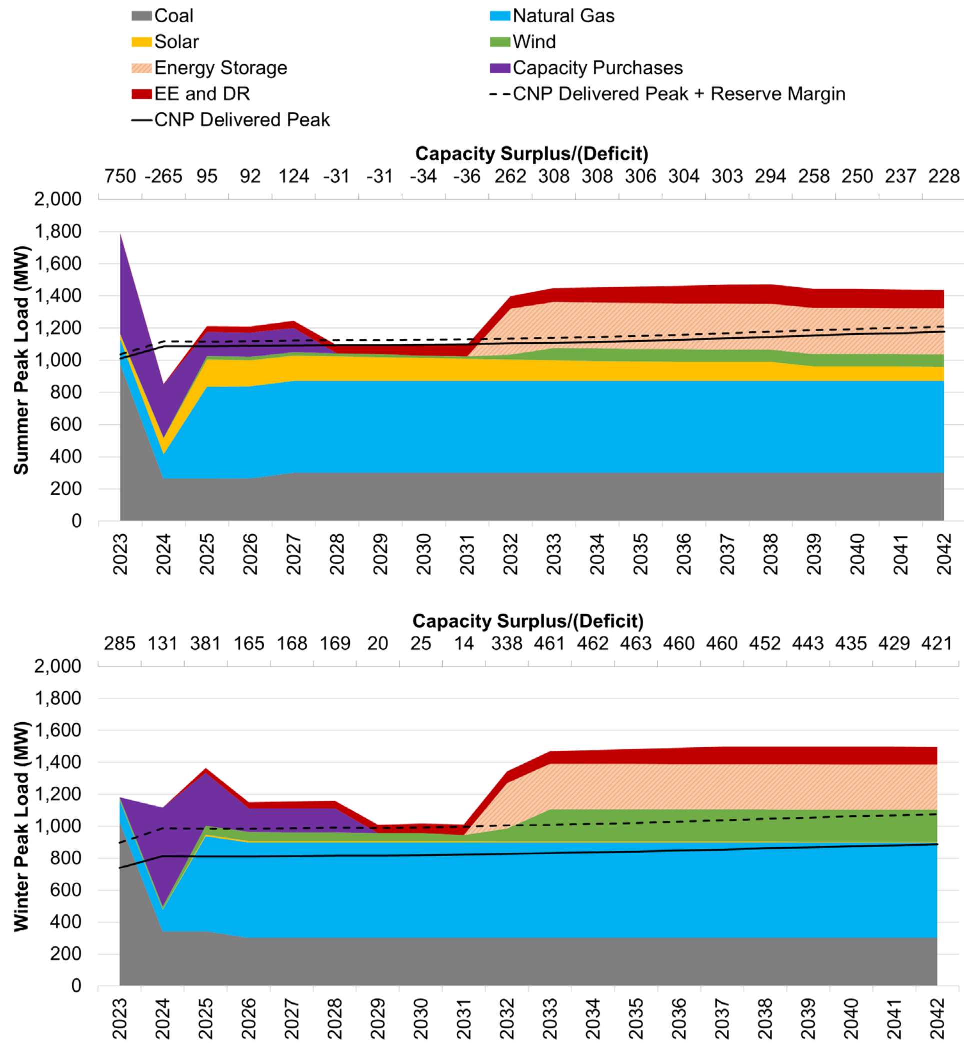


Business as Usual Portfolio Selection

CenterPoint Energy

- 2025 retirement of FB Culley 2
- Continue FB Culley 3 operations through study period
- Wind in the 2030s
- Long Duration Storage in 2032

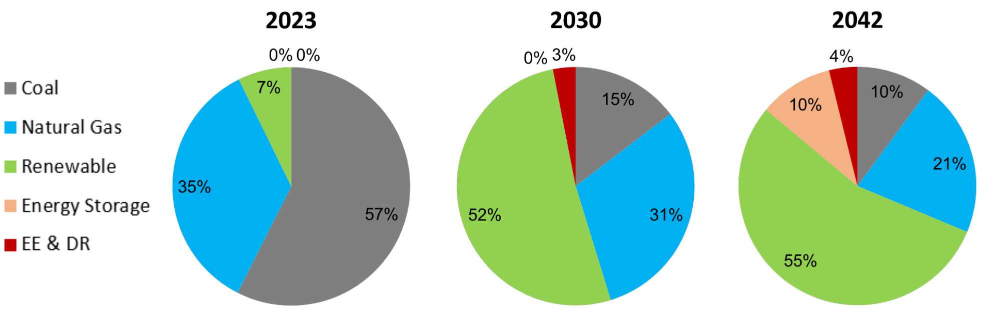
Balance of Loads and Resources



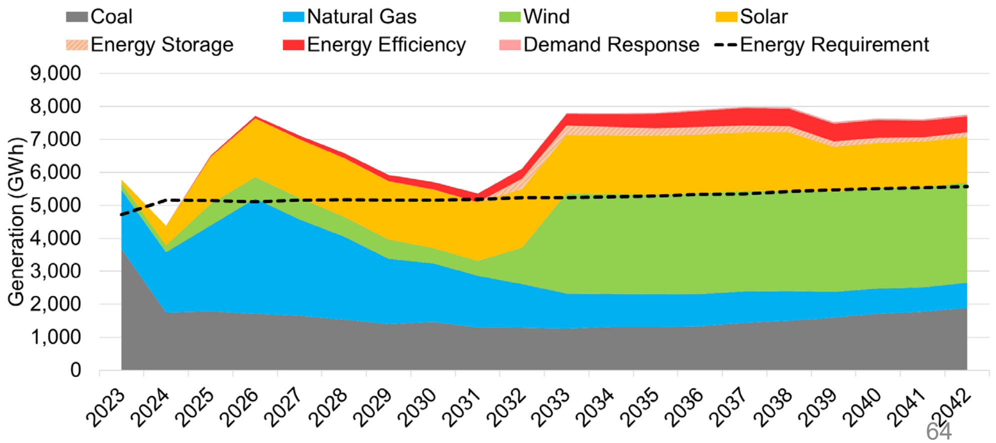
Business as Usual Portfolio Selection

- 2025 retirement of FB Culley 2
- Continue FB Culley 3 operations through study period
- Wind in the 2030s
- Long Duration Storage in 2032

Installed Capacity



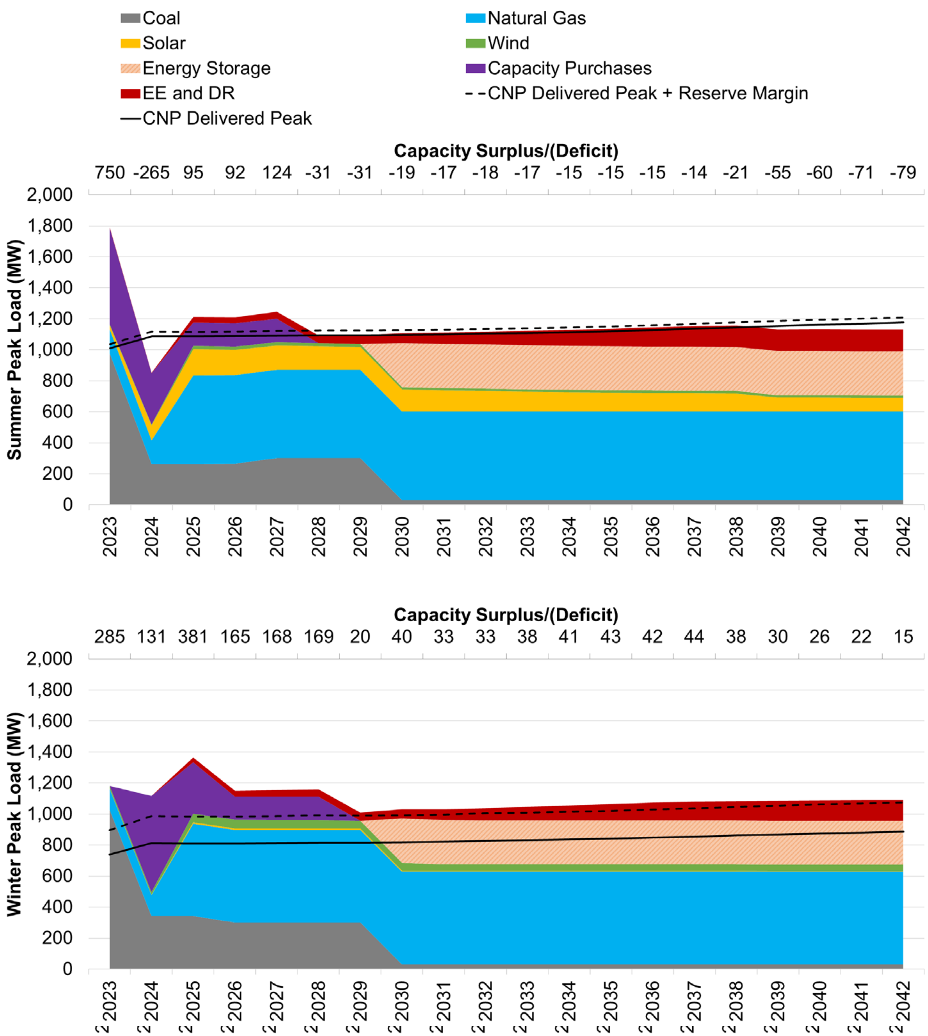
Energy Generation Mix



Replace Culley With Storage Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Storage in 2030

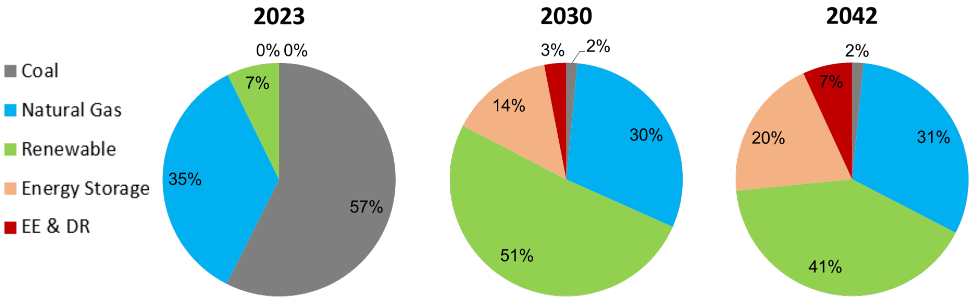
Balance of Loads and Resources



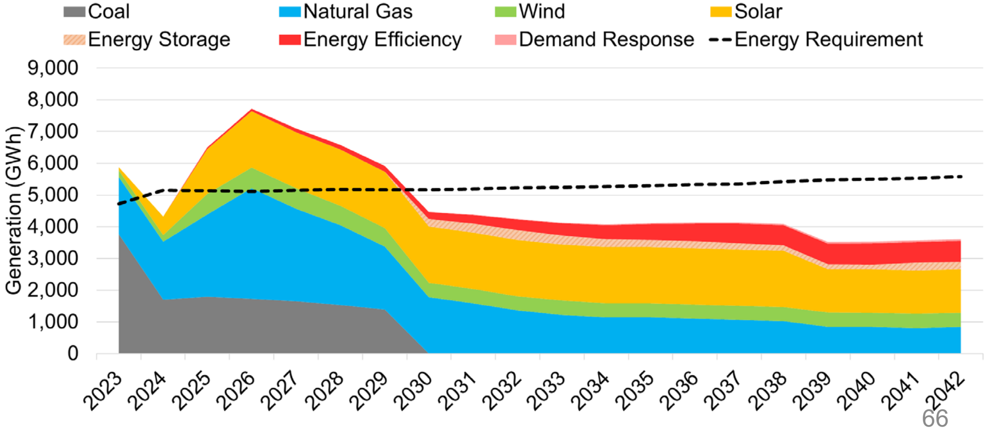
Replace Culley With Storage Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Storage in 2030

Installed Capacity



Energy Generation Mix

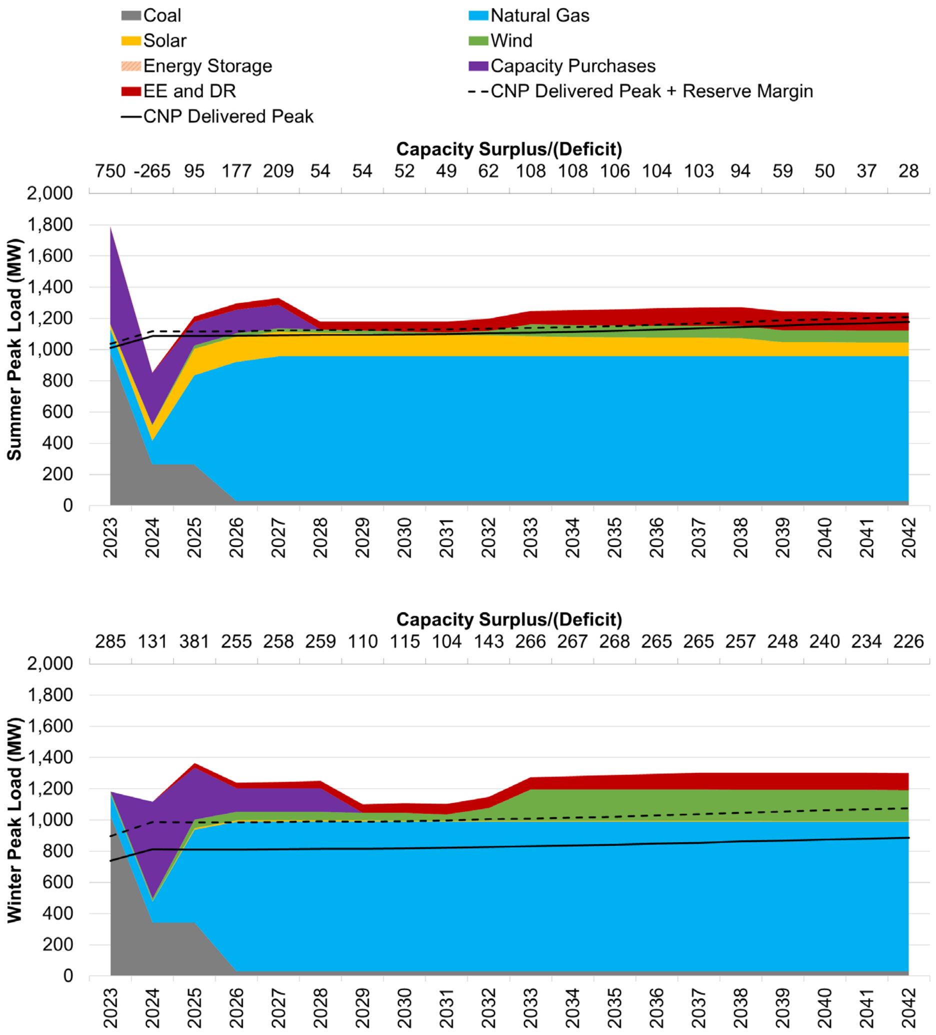


Convert Culley to Natural Gas Portfolio Selection

CenterPoint Energy

- Convert FB Culley 2 & 3 to gas in 2026
- Wind in the 2030s

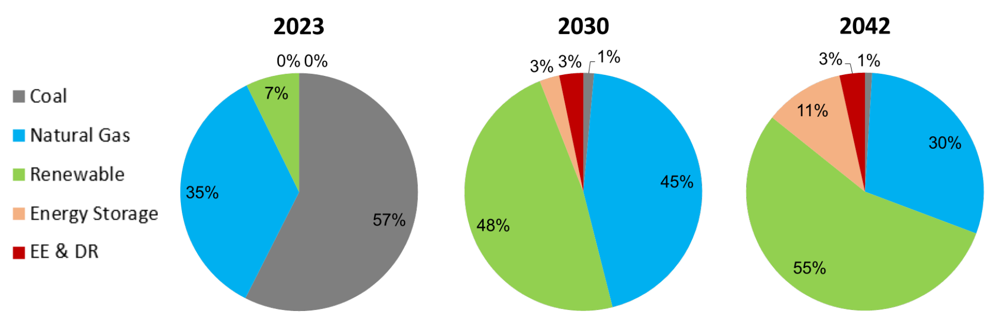
Balance of Loads and Resources



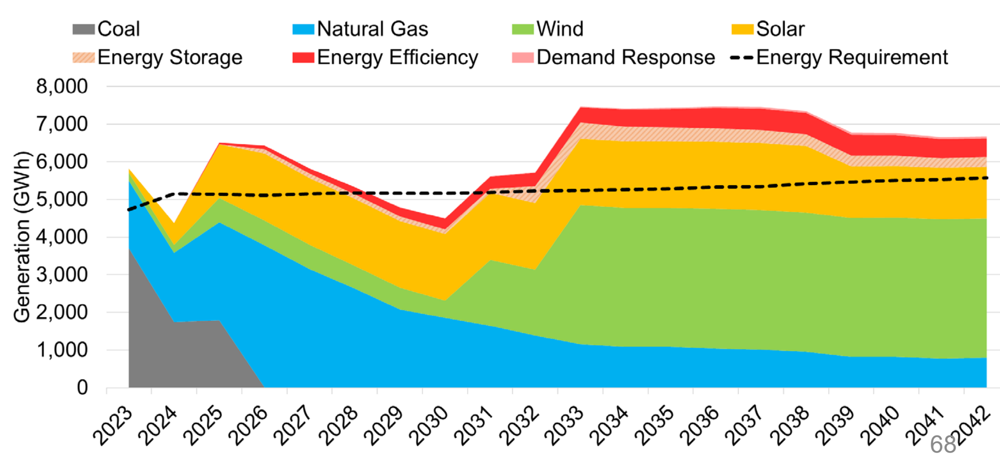
Convert Culley to Natural Gas Portfolio Selection

- Convert FB Culley 2 & 3 to gas in 2026
- Wind in the 2030s

Installed Capacity

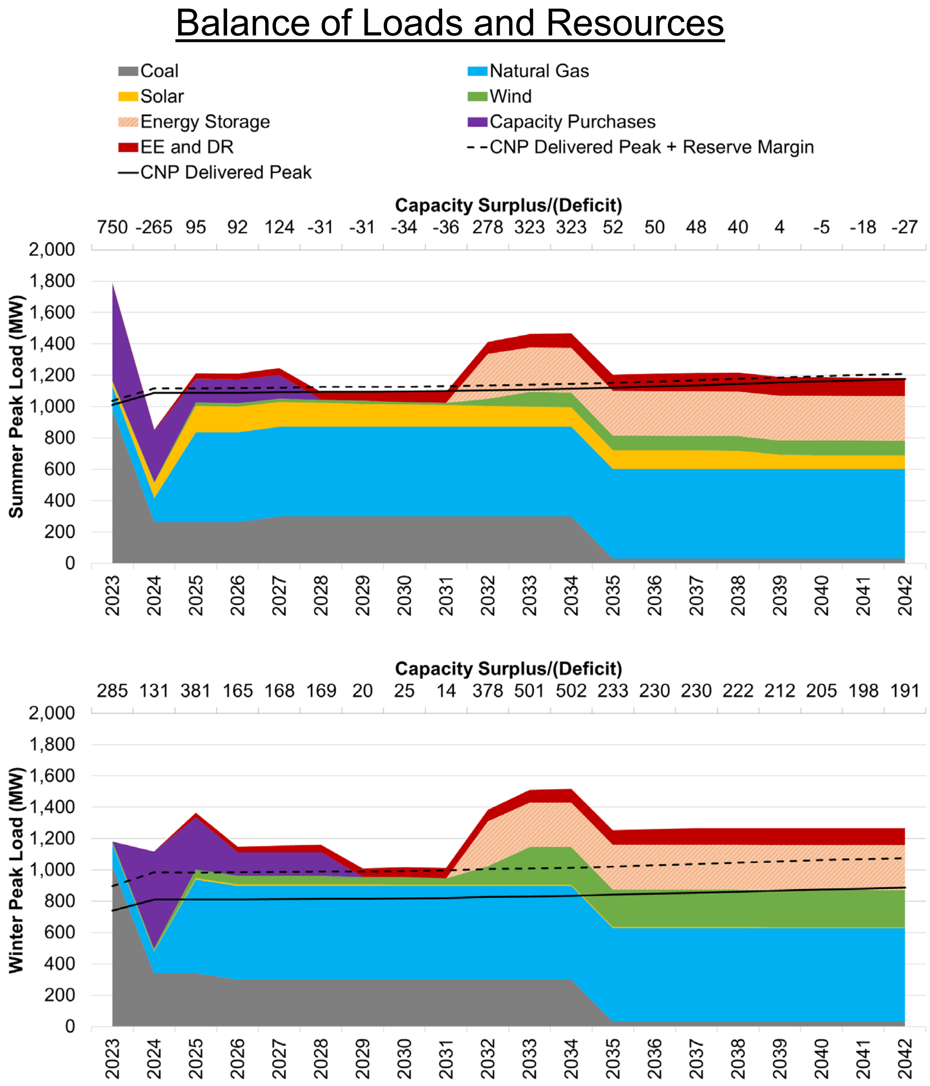


Energy Generation Mix



High Renewables & Storage by 2035 Portfolio Selection

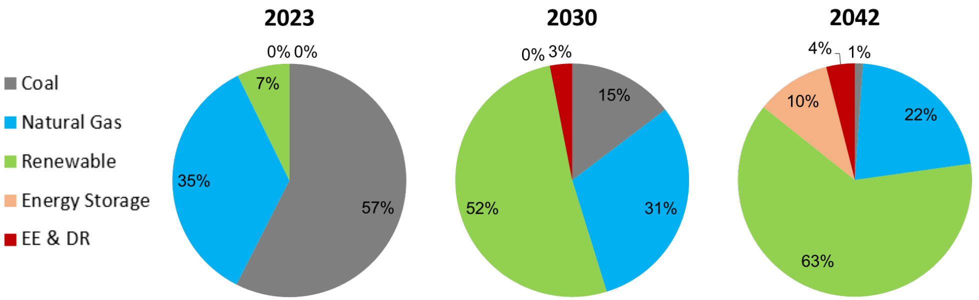
- 2025 retirement of FB Culley 2
- 2034 retirement of FB Culley 3
- Additional wind and storage in the 2030s



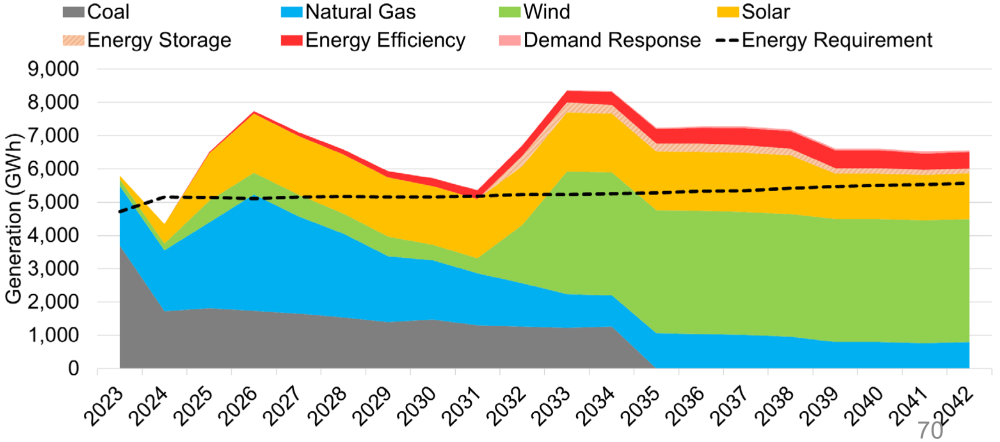
High Renewables & Storage by 2035 Portfolio Selection

- 2025 retirement of FB Culley 2
- 2034 retirement of FB Culley 3
- Additional wind and storage in the 2030s

Installed Capacity

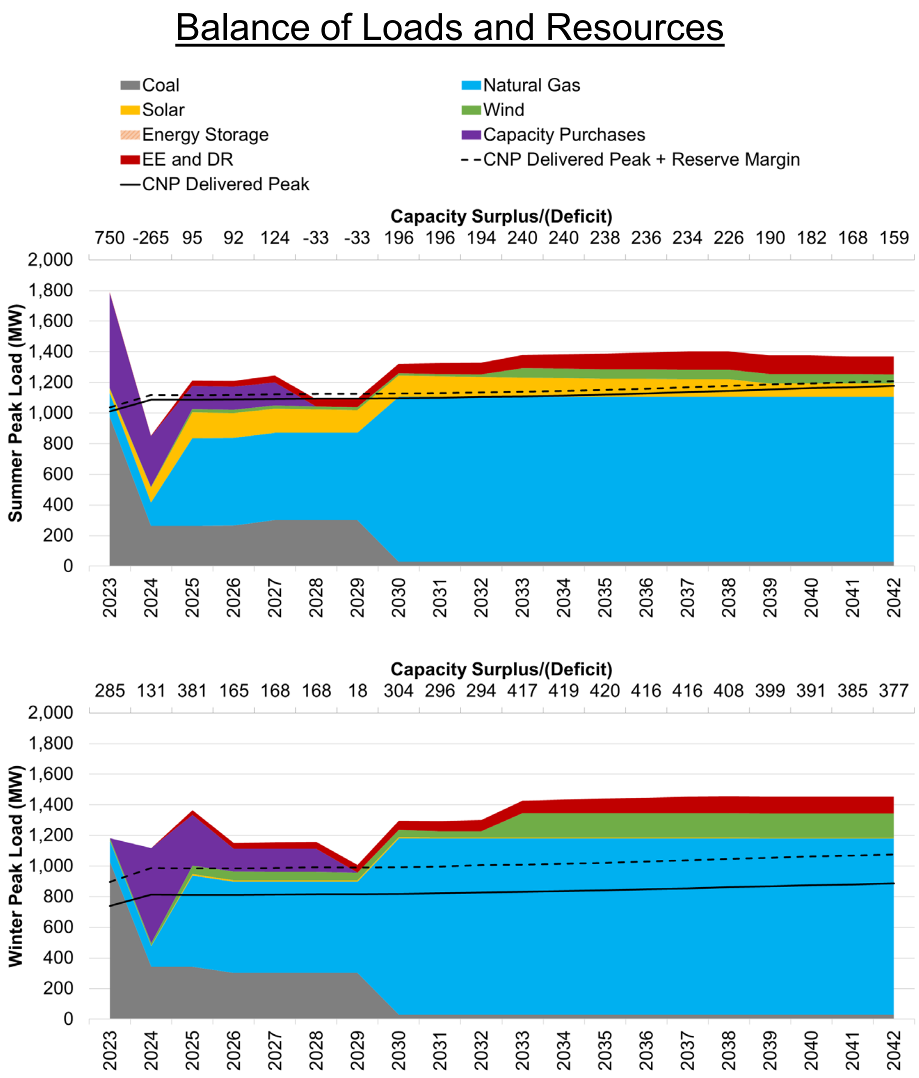


Energy Generation Mix



J-Class CCGT Portfolio Selection

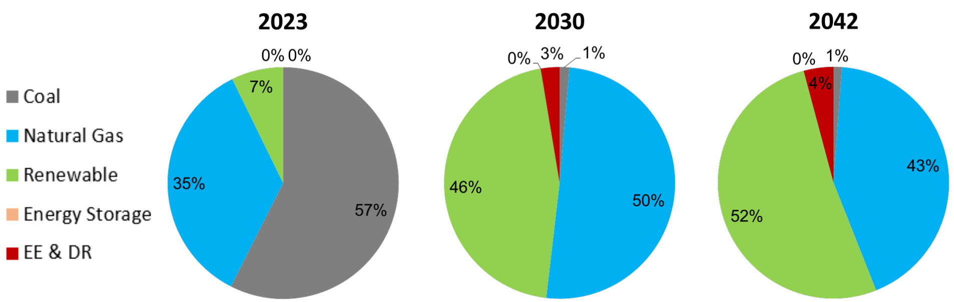
- J-Class Combined Cycle in 2030
- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Additional wind in the 2030s



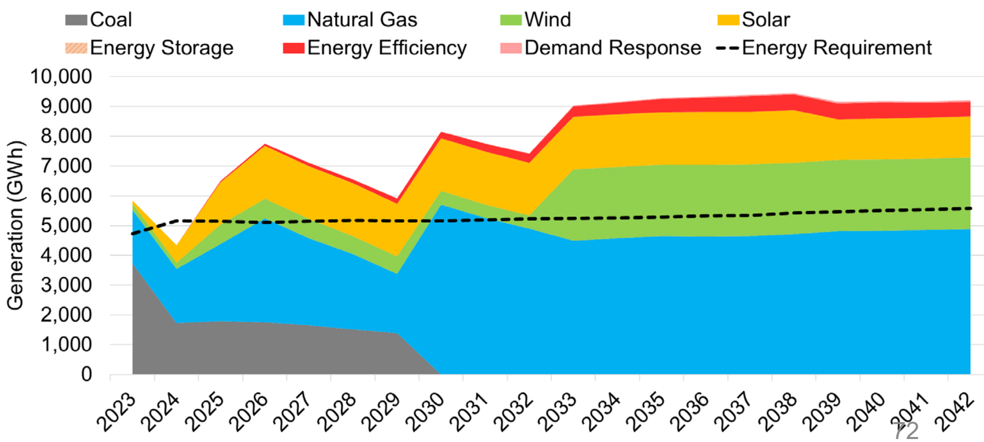
J-Class CCGT Portfolio Selection

- J-Class Combined Cycle in 2030
- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Additional wind in the 2030s

Installed Capacity



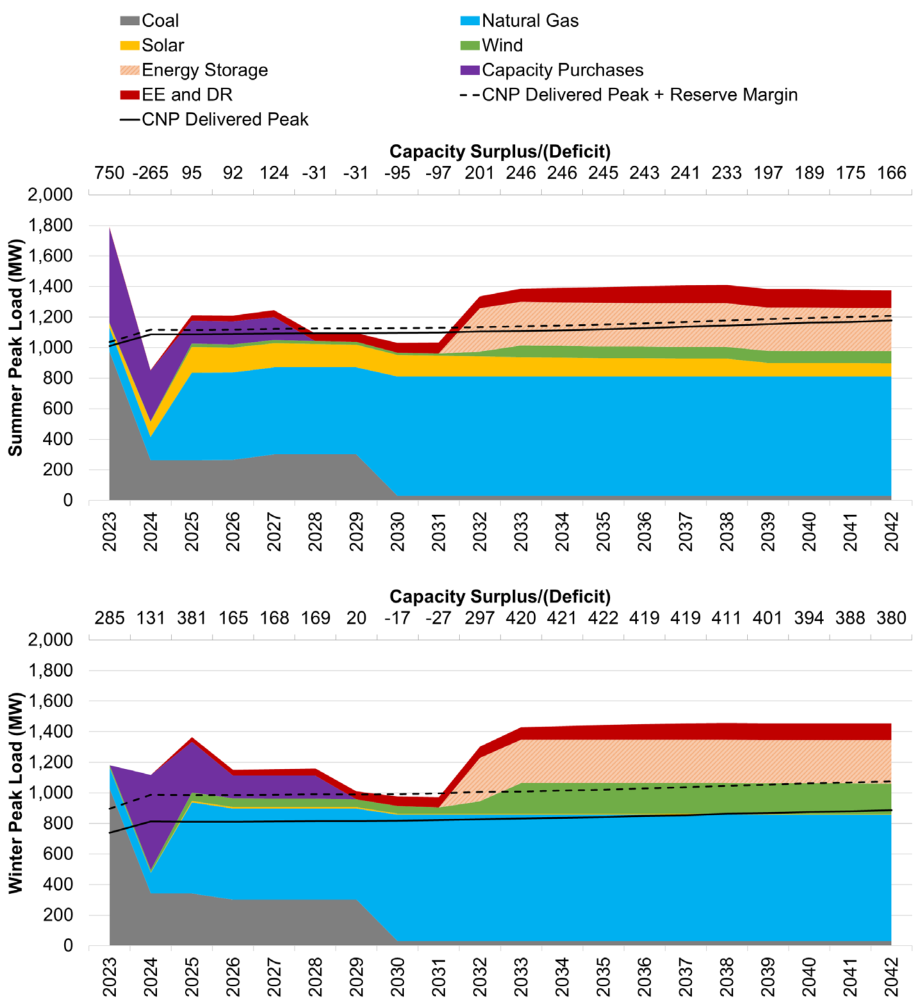
Energy Generation Mix



F-Class CT Portfolio Selection

- F-Class CT in 2030
- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Additional wind and storage in the 2030s

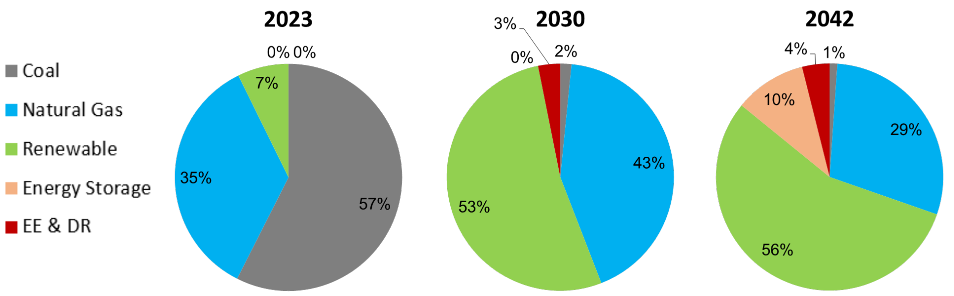
Balance of Loads and Resources



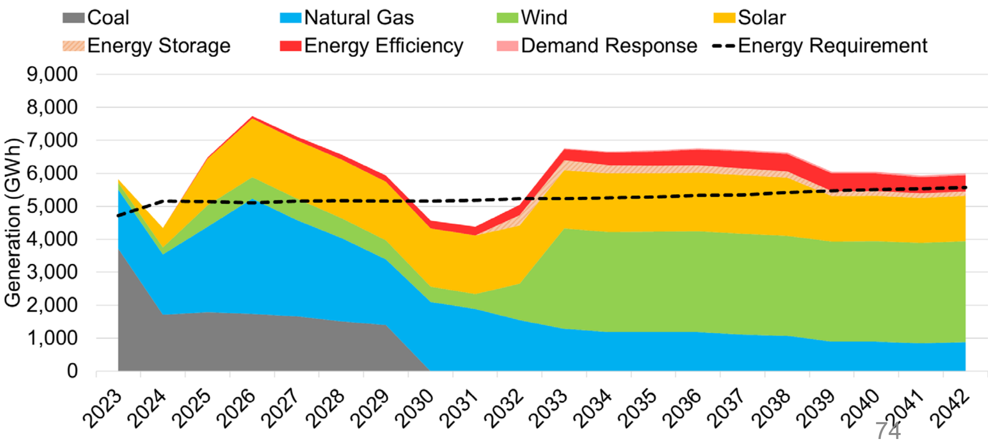
F-Class CT Portfolio Selection

- F-Class CT in 2030
- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Additional wind and storage in the 2030s

Installed Capacity



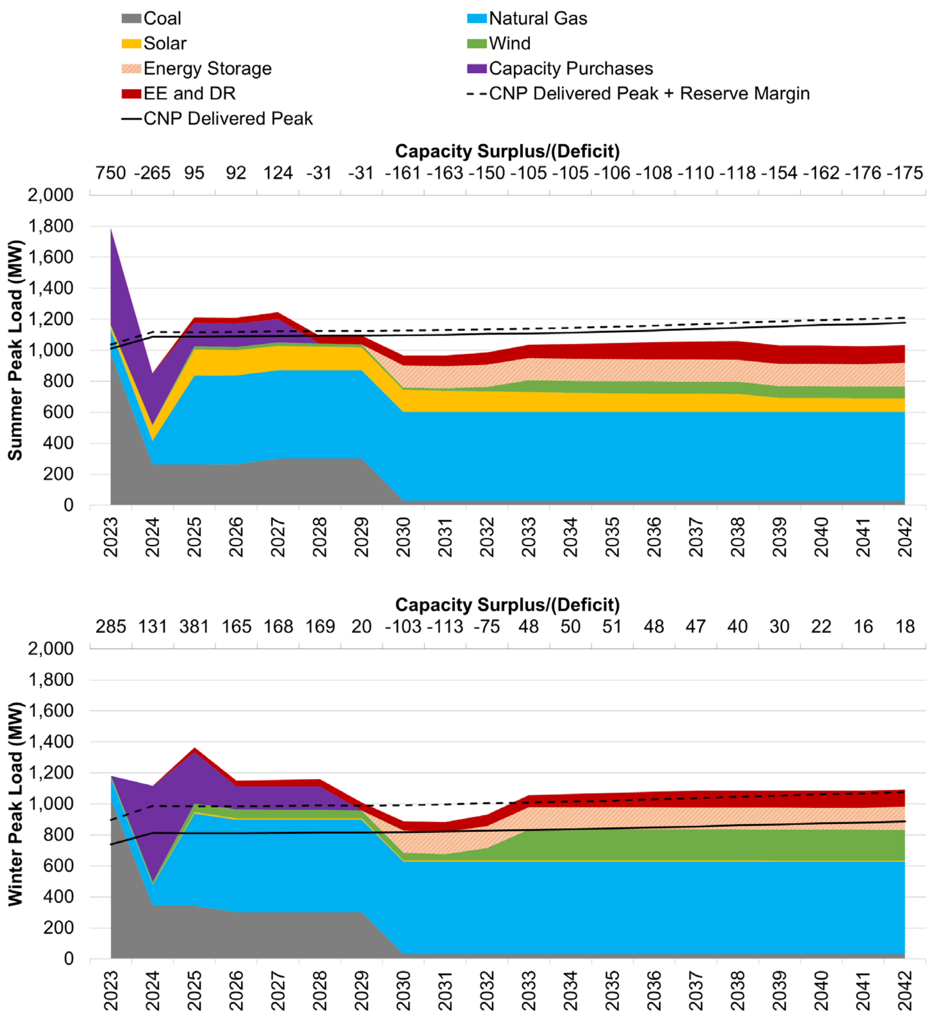
Energy Generation Mix



No AB Brown CCGT Conversion Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Additional wind and storage in the 2030s
- 10 MW storage in 2042

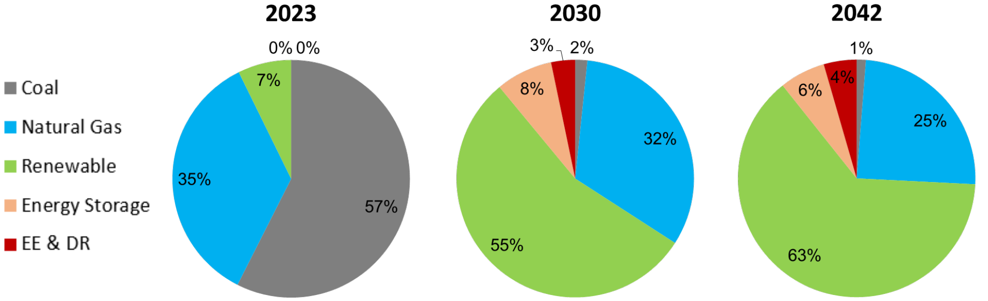
Balance of Loads and Resources



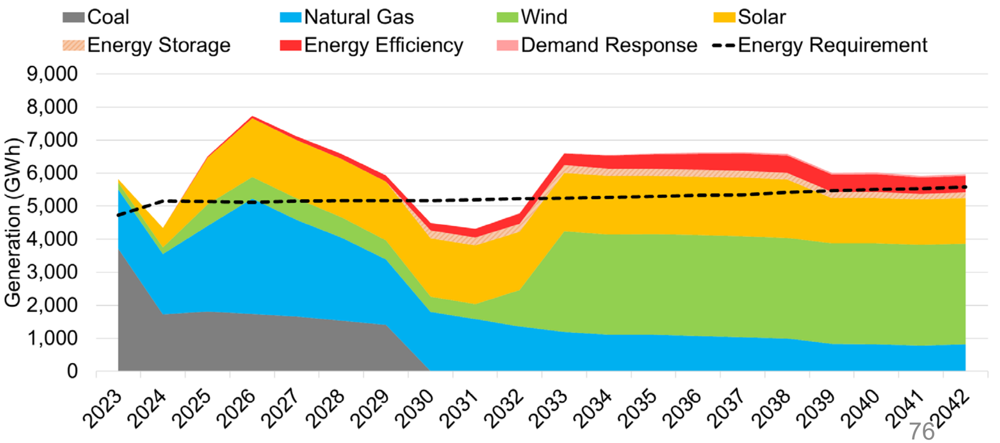
No AB Brown CCGT Conversion Portfolio Selection

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Additional wind and storage in the 2030s
- 10 MW storage in 2042

Installed Capacity



Energy Generation Mix



Scorecard

Scorecard		Affordability	Cost Risk		Environmental Sustainability		Reliability		Market Risk Minimization		Execution
Portfolio Strategy Group	Portfolio	20 Year NPVRR ($M)	Proportion of Energy Generated by Resources With Exposure to Coal and Gas Markets and Market Purchases (%)	95% Value of NPVRR ($)	CO2 Intensity (Tons CO_2e/kwh)	CO2 Equivalent Emissions (Stack Emissions) (Tons CO_2e)	Must Meet MISO Planning Reserve Margin Requirement in All Seasons (MW)	Spinning Reserve\ Fast Start Capability (%)	Energy Market Purchases or Sales (%)	Capacity Market Purchases or Sales (%)	Assess Challenges of Implementing Each Portfolio
Reference	Reference Case										
BAU	Business as Usual										
Scenario Based	Market Driven Innovation										
	High Regulatory										
	Decarbonization/Electrification										
	Continued High Inflation & Supply Chain Issues										
Replacement of FB Culley	Convert Culley to Natural Gas										
	J-Class CCGT										
	F-Class CT										
	Replace Culley with Storage										
	High Renewables & Storage by 2035										
	No AB Brown CCGT Conversion										

Q&A

CenterPoint Energy

Appendix

Draft Reference Case Inputs

Input	Unit	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal (ILB)	$/MMBtu	4.39	3.09	2.77	2.81	2.78	2.85	2.90	2.91	3.02	3.06	3.16	3.24	3.33	3.41	3.51	3.58	3.66	3.75	3.84	3.96
CO2	$/short ton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas (Henry Hub)	$/MMBtu	5.68	4.65	4.43	4.50	4.57	4.70	4.87	5.05	5.23	5.39	5.55	5.72	5.83	6.03	6.26	6.48	6.71	7.00	7.22	7.59
Peak Load	MW	1,010	1,087	1,087	1,088	1,092	1,095	1,095	1,096	1,100	1,105	1,110	1,114	1,120	1,128	1,136	1,145	1,154	1,162	1,169	1,177
Wind (200 MW)	$/kW	[redacted]				2,056	2,008	1,956	1,901	1,925	1,949	1,974	1,998	2,023	2,047	2,072	2,097	2,121	2,146	2,171	2,196
Solar (100 MW)	$/kW	[redacted]				1,891	1,836	1,777	1,714	1,737	1,761	1,785	1,809	1,834	1,858	1,883	1,908	1,933	1,958	1,983	2,009
Storage (100 MW)	$/kW	[redacted]				1,711	1,669	1,643	1,614	1,632	1,648	1,664	1,680	1,696	1,712	1,727	1,743	1,758	1,773	1,788	1,802

All values are Nominal $'s

Draft High Regulatory Case Inputs

CenterPoint Energy

Input	Unit	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal (ILB)	$/MMBtu	4.39	3.09	3.13	3.16	3.19	3.22	3.31	3.34	3.48	3.52	3.67	3.77	3.88	4.00	4.12	4.22	4.34	4.45	4.58	4.71
CO2	$/short ton	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas (Henry Hub)	$/MMBtu	5.68	4.65	5.64	6.63	7.62	8.61	8.85	9.44	10.00	10.51	11.01	11.47	11.55	11.68	12.09	12.42	12.64	13.19	13.58	14.31
Peak Load	MW	1,010	1,087	1,085	1,083	1,081	1,080	1,078	1,077	1,080	1,082	1,084	1,086	1,090	1,094	1,099	1,105	1,111	1,115	1,118	1,123
Wind (200 MW)	$/kW	[redacted]				2,056	2,008	1,956	1,901	1,858	1,815	1,772	1,729	1,686	1,643	1,600	1,557	1,514	1,471	1,428	1,385
Solar (100 MW)	$/kW	[redacted]				1,663	1,626	1,589	1,552	1,515	1,478	1,442	1,405	1,368	1,331	1,294	1,257	1,220	1,183	1,146	1,109
Storage (100 MW)	$/kW	[redacted]				1,431	1,419	1,407	1,395	1,383	1,372	1,360	1,348	1,336	1,324	1,312	1,300	1,289	1,277	1,265	1,253

All values are Nominal $'s

Draft Market Driven Innovation Case Inputs

Input	Unit	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal (ILB)	$/MMBtu	4.39	3.09	2.77	2.62	2.46	2.47	2.49	2.48	2.55	2.60	2.64	2.71	2.79	2.81	2.91	2.94	2.97	3.05	3.10	3.21
CO2	$/short ton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas (Henry Hub)	$/MMBtu	5.68	4.65	4.29	3.93	3.57	3.21	3.34	3.38	3.44	3.49	3.55	3.62	3.73	3.93	4.08	4.26	4.47	4.66	4.81	5.06
Peak Load	MW	1,010	1,087	1,093	1,098	1,104	1,110	1,112	1,115	1,120	1,128	1,135	1,142	1,150	1,162	1,174	1,185	1,197	1,209	1,220	1,231
Wind (200 MW)	$/kW	[redacted]				2,056	2,008	1,956	1,901	1,858	1,815	1,772	1,729	1,686	1,643	1,600	1,557	1,514	1,471	1,428	1,385
Solar (100 MW)	$/kW	[redacted]				1,663	1,626	1,589	1,552	1,515	1,478	1,442	1,405	1,368	1,331	1,294	1,257	1,220	1,183	1,146	1,109
Storage (100 MW)	$/kW	[redacted]				1,431	1,419	1,407	1,395	1,383	1,372	1,360	1,348	1,336	1,324	1,312	1,300	1,289	1,277	1,265	1,253

All values are Nominal $'s

Draft Decarbonization/Electrification Case Inputs

Input	Unit	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal (ILB)	$/MMBtu	4.39	3.09	3.13	3.16	3.19	3.22	3.31	3.34	3.48	3.52	3.67	3.77	3.88	4.00	4.12	4.22	4.34	4.45	4.58	4.71
CO2	$/short ton	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas (Henry Hub)	$/MMBtu	5.68	4.65	4.43	4.50	4.57	4.70	4.87	5.05	5.23	5.39	5.55	5.72	5.83	6.03	6.26	6.48	6.71	7.00	7.22	7.59
Peak Load	MW	1,010	1,087	1,093	1,098	1,104	1,110	1,112	1,115	1,120	1,128	1,135	1,142	1,150	1,162	1,174	1,185	1,197	1,209	1,220	1,231
Wind (200 MW)	$/kW	[redacted]				2,056	2,008	1,956	1,901	1,925	1,949	1,974	1,998	2,023	2,047	2,072	2,097	2,121	2,146	2,171	2,196
Solar (100 MW)	$/kW	[redacted]				1,891	1,836	1,777	1,714	1,737	1,761	1,785	1,809	1,834	1,858	1,883	1,908	1,933	1,958	1,983	2,009
Storage (100 MW)	$/kW	[redacted]				1,711	1,669	1,643	1,614	1,632	1,648	1,664	1,680	1,696	1,712	1,727	1,743	1,758	1,773	1,788	1,802

All values are Nominal $'s

Draft Continued High Inflation and Supply Chain Issues Case Inputs

Input	Unit	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal (ILB)	$/MMBtu	4.39	3.09	3.13	3.16	3.19	3.22	3.31	3.34	3.48	3.52	3.67	3.77	3.88	4.00	4.12	4.22	4.34	4.45	4.58	4.71
CO2	$/short ton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas (Henry Hub)	$/MMBtu	5.68	4.65	5.04	5.42	5.80	6.19	6.39	6.70	7.01	7.28	7.55	7.81	7.92	8.12	8.42	8.69	8.94	9.32	9.60	10.11
Peak Load	MW	1,010	1,087	1,085	1,083	1,081	1,080	1,078	1,077	1,080	1,082	1,084	1,086	1,090	1,094	1,099	1,105	1,111	1,115	1,118	1,123
Wind (200 MW)	$/kW	[redacted]				2,148	2,198	2,248	2,299	2,352	2,406	2,461	2,518	2,575	2,634	2,695	2,757	2,820	2,884	2,951	3,018
Solar (100 MW)	$/kW	[redacted]				2,104	2,152	2,201	2,252	2,303	2,356	2,410	2,465	2,522	2,580	2,639	2,699	2,761	2,825	2,889	2,956
Storage (100 MW)	$/kW	[redacted]				2,331	2,385	2,439	2,495	2,553	2,611	2,671	2,732	2,795	2,859	2,924	2,991	3,060	3,130	3,202	3,275

All values are Nominal $'s

Definitions

Term	Definition
ACE	Affordable Clean Energy (ACE) Rule, establishes emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants
All-Source RFP	Request for proposals, regardless of source (renewable, thermal, storage, demand response)
BAGS	Broadway Avenue Gas Turbine
BTA	Build Transfer Agreement/Utility Ownership
C&I	Commercial and Industrial
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate
Capacity	The maximum output of electricity that a generator can produce under ideal conditions (megawatts)
CCGT	A combined-cycle power plant uses both a gas and a steam turbine together to produce up to 50 percent more electricity from the same fuel than a traditional simple-cycle plant. The waste heat from the gas turbine is routed to the nearby steam turbine, which generates extra power
CCR Rule	Coal Combustion Residuals Rule
CCS	Carbon Capture and Storage
CDD	Cooling Degree Day
CEI South	CenterPoint Energy Indiana South
CO_2	Carbon dioxide

Definitions Cont.

Term	Definition
CONE	Cost of New Entry
CPCN	A Certificate of Public Convenience and Necessity is required to be granted by the Commission for significant generation projects
CSAPR	Cross State Air Pollution Rule
DER	Distributed Energy Resource
Deterministic Modeling	Simulated dispatch of a portfolio in a determined future. Often computer generated portfolios are created by optimizing on cost to the customer
DLC	Direct Load Control
DR	Demand Response
DSM	Demand side management includes both Energy Efficiency and Demand Response programs to reduce customer demand for electricity
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines are U.S. national standards for wastewater discharges to surface waters and publicly owned treatment works
EnCompass	Electric modeling forecasting and analysis software
Energy	Amount of electricity (megawatt-hours) produced over a specific time period

Definitions Cont.

Term	Definition
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GW	Gigawatt (1,000 million watt), unit of electric power
GWh	Gigawatt Hour
HDD	Heating Degree Day
Henry Hub	Point of interconnection of interstate and intrastate natural gas pipelines as well as other related infrastructure in Erath, Louisiana
IDEM	Indiana Department of Environmental Management
Installed Capacity (ICAP)	Refers to generating capacity after ambient weather adjustments and before forced outages adjustments
Intermittent	An intermittent energy source is any source of energy that is not continuously available for conversion into electricity and outside direct control
IRP	Integrated Resource Plan is a comprehensive plan to meet customer load expectations
IURC	The Indiana Utility Regulatory Commission is the public utilities commission of the State of Indiana. The commission regulates electric, natural gas, telecommunications, steam, water and sewer utilities
KWh	Kilowatt Hour

Definitions Cont.

Term	Definition
LCOE	Levelized Cost of Energy, A measure that looks at cost and energy production over the life of an asset so different resources can be compared. Does not account for capacity value.
LMR	Load Modifying Resource
Local Clearing Requirement (LCR)	Capacity needs to be fulfilled by local resource zone
LRZ6	MISO Local Resource Zone 6
MATS	Mercury and Air Toxics Standard
Mine Mouth	At the mine location
MISO	Midcontinent Independent System Operator, an Independent System Operator (ISO) and Regional Transmission Organization(RTO) providing open-access transmission service and monitoring the high-voltage transmission system in the Midwest United States and Manitoba, Canada and a southern United States region which includes much of Arkansas, Mississippi, and Louisiana. MISO also operates one of the world's largest real-time energy markets
MMBTU	Million British Thermal Units
MPS	Market potential study - Determines the total market size (value/volume) for a DSM at a given period of time
MSA	Metropolitan Statistical Area
MW	Megawatt (million watt), unit of electric power
NAAQS	National Ambient Air Quality Standards

Definitions Cont.

Term	Definition
Name Plate Capacity	The intended full-load sustained output of a generation facility
NDA	Non-Disclosure Agreement
NOI	Notice of Intent
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPVRR	Net Present Value Revenue Requirement
NSPS	New Source Performance Standards
OMS	Organization of MISO States, was established to represent the collective interests of state and local utility regulators in the Midcontinent Independent System Operator (MISO) region and facilitate informed and efficient participation in related issues.
Peaking	Power plants that generally run only when there is a high demand, known as peak demand, for electricity
Planning Reserve Margin Requirement (PRMR)	Total capacity obligation each load serving entity needs to meet
Portfolio	A group of resources to meet customer load
PPA	Purchase Power Agreement

Definitions Cont.

Term	Definition
Preferred Portfolio	The IRP rule requires that utilities select the portfolio that performs the best, with consideration for cost, risk, reliability, and sustainability
Probabilistic modeling	Simulate dispatch of portfolios for a number of randomly generated potential future states, capturing performance measures
PV	Photovoltaic
RA (Resource Adequacy)	RA is a regulatory construct developed to ensure that there will be sufficient resources available to serve electric demand under all but the most extreme conditions
RAP	Realistic Achievable Potential
Resource	Supply side (generation) or demand side (Energy Efficiency, Demand Response, Load Shifting programs) to meet planning reserve margin requirements
SAC	Seasonal Accredited Capacity
Scenario	Potential future State-of-the-World designed to test portfolio performance in key risk areas important to management and stakeholders alike
SDE	Spray Dryer Evaporator
Sensitivity Analysis	Analysis to determine what risk factors portfolios are most sensitive to
SIP	State Implementation Plan
Spinning Reserve	Generation that is online and can quickly respond to changes in system load

Definitions Cont.

Term	Definition
T&D	Transmission and Distribution
Technology Assessment	An analysis that provides overnight and all-in costs and technical specifications for generation and storage resources
Unforced Capacity (UCAP)	A unit's generating capacity adjusted down for forced outage rates (thermal resources) or expected output during peak load (intermittent resources)
VAR Support	Unit by which reactive power is expressed in an AC electric power system
ZLD	Zero Liquid Discharge

CenterPoint 2022 IRP
3rd Stakeholder Meeting Minutes Q&A
December 13, 2022, 9:30 am – 3:00 pm CDT

Richard Leger (Senior Vice President, CenterPoint Energy) – Welcome, Safety Message

Matt Rice (Director, Regulatory and Rates, CenterPoint Energy) – Discussed the meeting agenda, guidelines for the meeting, discussed updates from the last stakeholder meeting including feedback, and the 2022/2023 IRP status update.

- Slide 10 Generation Transition Update:
  - Question: You mentioned the solar panel supply is the reason the solar project was pushed back a bit. Have you experienced any bottlenecks or roadblocks from MISO on these projects?
    - Response: Our projects are in the MISO 2020 queue, and it has been delayed a few times. It has pushed the Rustic Hill and Vermillion projects into 2025, and we don't expect to see an interconnection agreement until mid-2023.
- Slide 11 Stakeholder Feedback – Resources:
  - Question: I don't recall which technology was modeled for flow batteries in the last IRP. What is the preference for compressed air storage vs iron-air batteries?
    - Response: There's a lot of multi-day storage technologies being discussed in the market, but the viability of those is still being questioned and understood. Trying to balance commercial viability effectiveness is why we chose to model Compressed Air Storage.
  - Question: What about the new technology being created by FORM energy?
    - Response: We have heard of FORM energy, but everything that is being announced is in pilot and is several years out from being viable. We don't know if those technologies will come to fruition, and we cannot count on something that may not even be available.
- Slide 12 Stakeholder Feedback – Resources:
  - Question: For the repowering of the wind farms, is there a different or easier way to get a cost estimate for repowering wind farms?
    - Response: At this point, we don't have the cost estimate to repower the wind farm. We are in initial discussion on what we can do given our existing contracts. These contracts don't expire for a few years. If wind is selected in the model, it could be used as proxy for these existing wind contracts.
  - Question: You mentioned you would adjust up the capacity factor of wind because they are proving more resilient. Are you adjusting down the capacity factor of FB Culley 3 as it has been offline since June?
    - Response: When we looked at accreditation of existing units, we look at historical performance. We adjusted the accreditation of FB Culley 3 down for the next several years based on the current outage, but historically FB Culley has been a very reliable unit.
- Slide 16 Stakeholder Feedback – Resources:
  - Question: Can you clarify the decision to include the remaining book value of units in a retirement decision and to exclude inputting book value in units that continue to operate?
    - Response: We can discuss this offline to gain a better understanding of your feedback.
- General Questions:
  - Questions: For the FB Culley 3 gas conversion scenario, would that be a new gas pipeline? Are we bringing that pipeline in because there is not enough gas to supply this new peaking plant?
    - Response: It would be a new pipeline. The pipeline costs being modeled for a potential gas unit at FB Culley is separate from the line going to serve AB Brown for the new, approved CTs.[1]
  - Question: Why are the CTs at AB Brown being listed as Peaker plants? Are there black start capabilities?
    - Response: They are there to back up renewable resources when they are not providing enough energy to serve our customers. There are black start capabilities at that AB Brown.

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[1] Other questions were posed about gas pipelines that were outside of the scope of this IRP.

Matt Lind (Director, Resource Planning & Market Assessments, 1898 & Co.) – Discussed scorecard metrics and reviewed modeling scenarios.

- Slide 22 Updated IRP Draft Objectives and Measures:
  - Question: Is spinning reserve/ fast start referring to black start capability?
    - Response: Those are more in line with MISO. Spinning reserve would be for a plant that is already online. Black start is for units that can help bring the grid back online. I would not define that as black start.
- General Questions:
  - Question: Do you have any updates on when the repairs for FB Culley 3 are expected to be completed?
    - Response: They are expected to be done sometime between the end of February and early March. We are going to see what the capacity accreditation for all resources within CenterPoint's portfolio and reflect that in the modeling. We do expect for units like FB Culley that its capacity accreditation will be accounted for in the modeling. We are waiting for MISO's numbers. Resource reliability is important to CenterPoint, MISO, and everyone to keep the lights on.
  - Question: Where will we see a final accounting of what the unplanned outage of FB Culley is going to cost customers? Are those repair costs going to be passed on to customers?
    - Response: A sub-docket is expected to be opened with the IURC which will provide that information. The commission will set it up, and the public information will be on their website.
  - Question: Is the RFP final for this IRP cycle?
    - Response: The RFP is closed, and the information received from that RFP is reflected in the modeling assumptions. However, we are still receiving market information for wind projects through on-going negotiations for a wind project.

Brian Despard (Project Manager, Resource Planning & Market Assessments, 1898 & Co.) – Discussed updates to the probabilistic modeling approach and assumptions including inputs.

Kyle Combes (Project Manager, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the final 2022/2023 IRP resource inputs, seasonal accreditation, technical assessment, and cost curves.

- Slide 39 MISO Update:
  - Question: How is MISO treating storage? Is that still to be determined? How do you see them addressing storage accreditation?
    - Response: MISO has not said how they are treating storage; for now, we are giving it the 95% accreditation for 4-hour storage across the entire time period.
  - Question: Are these accreditation values marginal, not average? MISO derives them basically by taking out all renewables, performing a LOLE study and then adding them back in to rerun the analysis. These values are very different than the values finalized the week before. It seems like you are treating these as average values.
    - Response: These numbers are still not finalized. If you see anything that's not shared publicly from MISO, please let us know.
- General Questions:
  - Question: Can you talk at a high level about where the cost numbers for SMR's come from?
    - Response: Those cost come from our engineering department at Burns & McDonnell and their involvement in front end development in a few SMR projects.

Drew Burczyk (Consultant, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the 2022/2023 draft portfolios.

Drew Burczyk – Presented draft scenario optimization results including project selections, and portfolio breakdowns.

- Slide 47 Draft Optimized Portfolios:
  - Question: There is a difference in the 2024 makeup for the solar selections, why is that?
    - Response: There are different assumptions going into each scenario. Solar is selectable in each portfolio, but only being picked up in certain portfolios.

- Question: For the potential CT conversion to a Combined Cycle at AB Brown, what were the dates in which the model could choose that conversion? Is it correct that you cannot reuse injection rights and it would have to go through the whole MISO queue process?
    - Response: 2027 – 2042. Correct.
- General
  - Question: Hydroelectric is never mentioned in your predictions. There are two dams on the river that haven't been used. If there is federal funding available, would that make up for the cost factor?
    - Response: Hydroelectric technology is a selectable option, and it is not being picked up as the best option. We will be happy to add a portfolio or two that add hydroelectric.
  - Question: Can you talk briefly about how you developed the cost and performance assumptions for the hydroelectric resources? Is it a run of river plant?
    - Response: The information came from the US Corps of Engineers study and costs associated with Cannelton. We can double check that second question [Confirmed Cannelton is a run-of-the-river hydro power plant].
  - Question: What do you expect for the next iteration of portfolios in regard to limiting sales?
    - Response: That is more focused on deterministic portfolios and less on optimized portfolios. We are using 15% of peak load for purchases and sales on the capacity expansion step. Once we step into the 8760 dispatch of the model, we increase that to 750 MW to be aligned with CenterPoint's import/export capabilities.
  - Question: Are you planning to update these assumptions for the proposed enhancement to the Planning Resource Auction (PRA) construct? They are changing the way that maximum capacity price would be assigned.
    - Response: We have not made any of those adjustments, but if you have any feedback, we are open to that.
  - Question: How would the Combined Cycle conversion work? Are you going to build them with the approved Certificate of Public Convenience and Necessity (CPCN) and then later convert them? Would you need a 2nd CPCN and then convert them?
    - Response: It's just an option with all the portfolios. If we were to go down that path, we would need another CPCN to go on and install the Heat Recovery Steam Generator(s) to be considered a Combined Cycle. Just like any new generation resource selected in the IRP.

Drew Burczyk – Presented draft deterministic portfolio results including project selections, and portfolio breakdowns.

- General
  - Question: Could you share information about exiting the Warrick 4 plant? What is involved with exiting Warrick 4?
    - Response: Our intent is to exit our agreement with Warrick at the end of 2023. We do have a capacity need in 2024/2025. If we can come to an agreement and at a reasonable cost compared to capacity purchases, there's a possibly that we can continue the Warrick 4 agreement until 2025 when the CTs come online.

Open Q&A Session

No questions.

Comments of CAC on CenterPoint's EnCompass Modeling Files

Submitted to CenterPoint Energy Indiana South on January 6, 2023

Comments on CenterPoint's EnCompass Modeling Files

Citizens Action Coalition of Indiana ("CAC") submits these comments on CenterPoint Energy Indiana South's ("CenterPoint") EnCompass modeling files that were provided to stakeholders on December 22, 2022. We appreciate the opportunity to review the latest version of modeling files. Our consultants' review of the files has led to additional questions on the inputs. We would like to submit the following feedback and questions to CenterPoint on the EnCompass modeling files.

1 Access to Supporting Information for Modeling Inputs

We appreciate the opportunity to review and provide feedback on important modeling inputs. We believe there are still a few outstanding items that would assist us in providing additional feedback to CenterPoint and 1898 on the modeling. We ask that CenterPoint share the following information with technical stakeholders:

- Supporting workbooks for the development of the seasonal coincidence factors that were incorporated into the development of the reserve margin requirement input.
- Seasonal accreditation values for CenterPoint's thermal units. At this time, it is unclear how some of the seasonal firm capacity values were developed.
- CenterPoint's thermal units. It is our understanding that some of the time series in the model may have a mixture of capital expenditures and fixed O&M together. It is challenging to provide feedback on those inputs if we are not sure what the allocation is for the costs (i.e., breakdown between capital, fixed O&M, and any costs for pipelines or firm gas transportation). For instance, it is not clear what costs are being modeled specific to the consideration of converting the Culley units to gas. Additional information to support these time series would be extremely helpful for us to understand how the costs are developed for the time series in EnCompass.

1.1 Timing of Remaining Workshops and Stakeholder Input

During the December meeting, CenterPoint seemed to be saying that the modeling inputs would largely be finalized after comments were received on January 6th. Because of the volume of missing data and the numerous questions we have about the data provided so far, we are concerned that there is not enough time being allocated to allow for thorough stakeholder input. Given that there is still nearly five months before CenterPoint submits its IRP, we hope that CenterPoint will provide additional flexibility to allow for continued stakeholder input after answering our questions and providing the requested information. If that is not what CenterPoint intended to communicate at the December meeting then we would welcome clarification of that as well.

2 EnCompass Modeling Files

We have reviewed the EnCompass modeling inputs and offer the following comments and questions to CenterPoint related to the modeling inputs shared with stakeholders.

Comments on CenterPoint's EnCompass Modeling Files

2.1 New Resources

Renewable and Battery Storage

1. How are the Inflation Reduction Act ("IRA") tax credits incorporated into the costs of new generic solar resources? It looks the time series named "PTC" is only applied as a negative $/MWH cost for the new wind resources; changes to Sections 45 and 45Y of the Internal Revenue Code now allow the Production Tax Credit to apply to solar projects.
2. How is the IRA reflected for the hybrid resources? Is there an allocation for the Investment Tax Credit ("ITC") for the battery portion of the project or a full ITC applied to the project?
3. Did CenterPoint and 1898 considered modeling the solar hybrid resources with two distinct resources for the battery portion of the hybrid project to reflect the ability for the storage resource to not be restricted to only charging from the solar resource?
4. For the dataset named "SES - Renewable High," how did CenterPoint and 1898 determine the increase to apply to the resources modeled to reflect the RFP bids?

Hydro

We appreciate CenterPoint and 1898 taking the time to set up and offer new hydro resources in the model. After reviewing the inputs, we have several questions and would like to request additional information on the input assumptions.

1. Are any tax credits from the Inflation Reduction Act incorporated into the capital expenditures modeled for the hydro resources?
2. During the last stakeholder IRP meeting, it was our understanding that 1898 and CenterPoint referenced an Army Corps of Engineers Report that was used to develop the cost estimates for the resources. Is this 2013 report[1] the document that was referenced? If not, which report was used? Either way, can CenterPoint provide the spreadsheet(s) used to develop the cost inputs?
3. How did CenterPoint and 1898 develop the hourly shape for the hydro resources?

Capacity Purchases

1. Will any of the resources with the name "Capacity Purchase" need adjustments to their Firm Capacity in order to reflect MISO's new seasonal RA construct or will CenterPoint still receive the same firm capacity for these purchases in all seasons?

2.2 Energy Efficiency and Demand Response

1. Are the currently approved energy efficiency programs incorporated into the model as a reduction to the load forecast? If not, how are they accounted for?

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[1] https://www.hydro.org/wp-content/uploads/2014/01/Army-Corps-NPD-Assessment.pdf

2. Would CenterPoint and 1898 be able to provide a description for some of the energy efficiency resources in EnCompass so that stakeholders can map them to the information from the Market Potential Study? (For example, the resources named "CI Enhanced," "HER V1," "RES High," and "RES LowMed.")
3. Since the EnCompass inputs only seem to have three resources for C&I energy efficiency savings, will this be the only level of savings for C&I included in the modeling?
4. Could CenterPoint and 1898 provide stakeholders with the supporting workbooks used to develop the levelized costs modeled for the new energy efficiency and demand response resources?

2.3 ELCC Values of Wind and Solar

The accredited values of solar and wind will likely have significant implications for whether those resources are chosen in the resource optimization. CenterPoint stated in the December 13, 2022, Public Stakeholder meeting that it will base the capacity value for solar and wind resources on a proposed change to non-thermal accredited values, the Direct-LOL approach, under discussion at MISO. While MISO has not yet even filed for approval of this proposal at FERC, the proposal has not been met with support amongst stakeholders. Of the seventeen parties or coalitions who submitted comment[2] to MISO last month, all either opposed MISO's proposal or raised concerns about it. For example, Xcel Energy stated, "LOL hours favor the very peak hours so this method would accredit wind and solar resource based only on a few hours where the modeled generation supply is inadequate to serve the modeled load. This is not in alignment with the PRM which is calculated across all hours. We consider the Direct-LOL methodology to be a marginal accreditation approach."

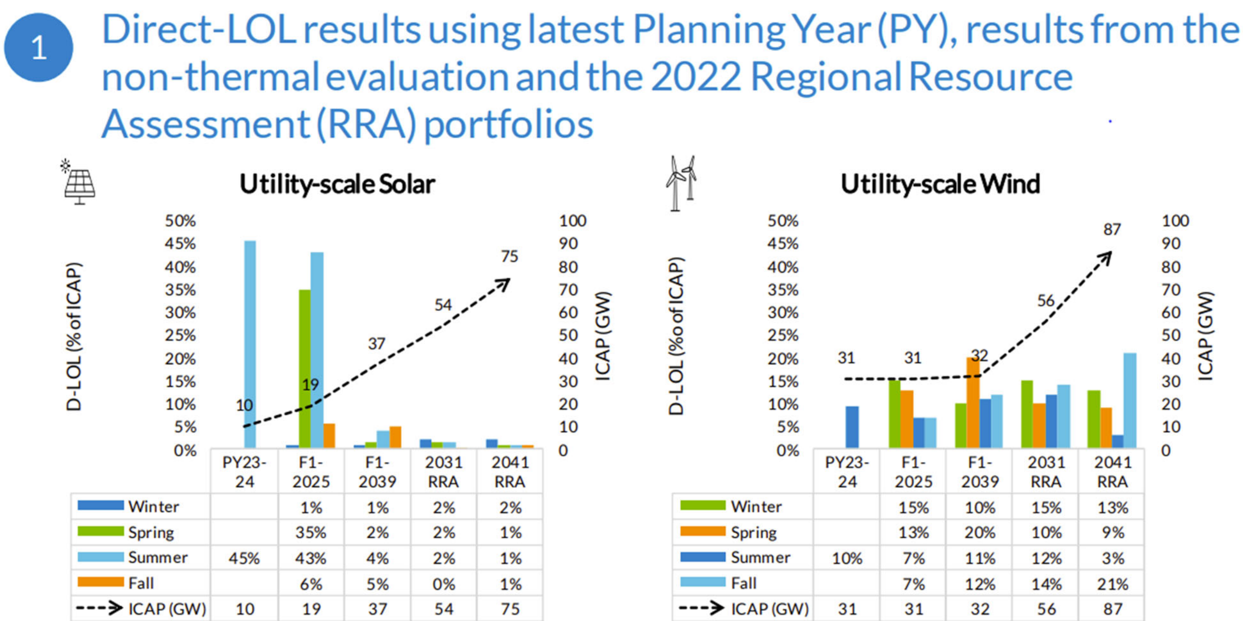
We have heard indirectly from MISO that the 2022 Regional Resource Assessment[3] accredited capacity values represent the official forward looking projection from MISO, whereas other capacity accreditation values, such as those projected in MISO's November 30, 2022 presentation,[4] should be used as sensitivities. We would recommend that CenterPoint adopt this approach here as well.

The values presented at CenterPoint's December 13th stakeholder meeting, shown below, would then become a sensitivity.

[2] All of the December 2022 stakeholder comments may be found at https://www.misoenergy.org/stakeholder-engagement/stakeholder-feedback/2022/rasc-wind-solar-accreditation-recommendation-rasc-2020-4-rasc-2019-2-20221130.

[3] See https://cdn.misoenergy.org/20221110%20RRA%20Workshop%20Presentation626925.pdf, slides 33-36.

[4] See https://cdn.misoenergy.org/20221130%20RASC%20Item%2007b%20Non-Thermal%20Accreditation%20Presentation%20(RASC-2020-4%202019-2)627100.pdf, slide 12.



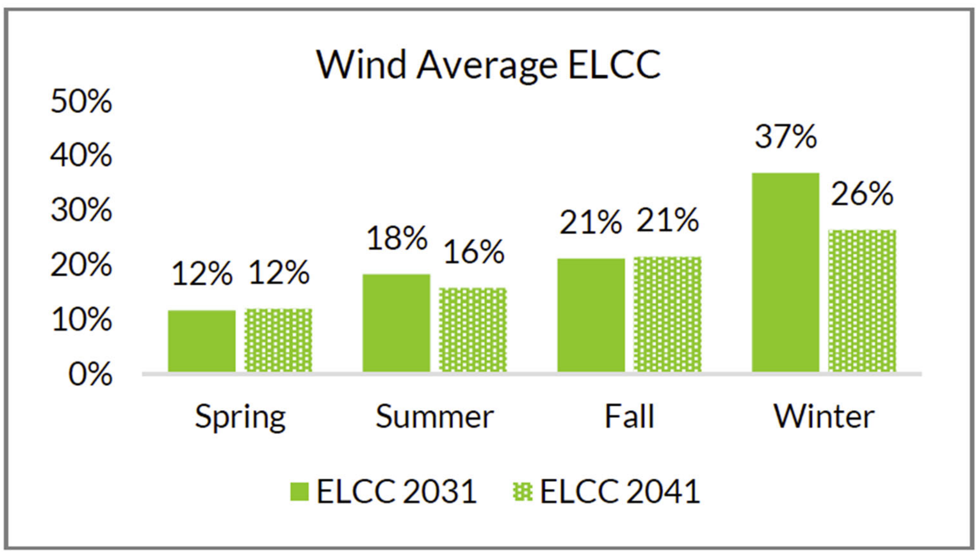
Utility-scale Solar

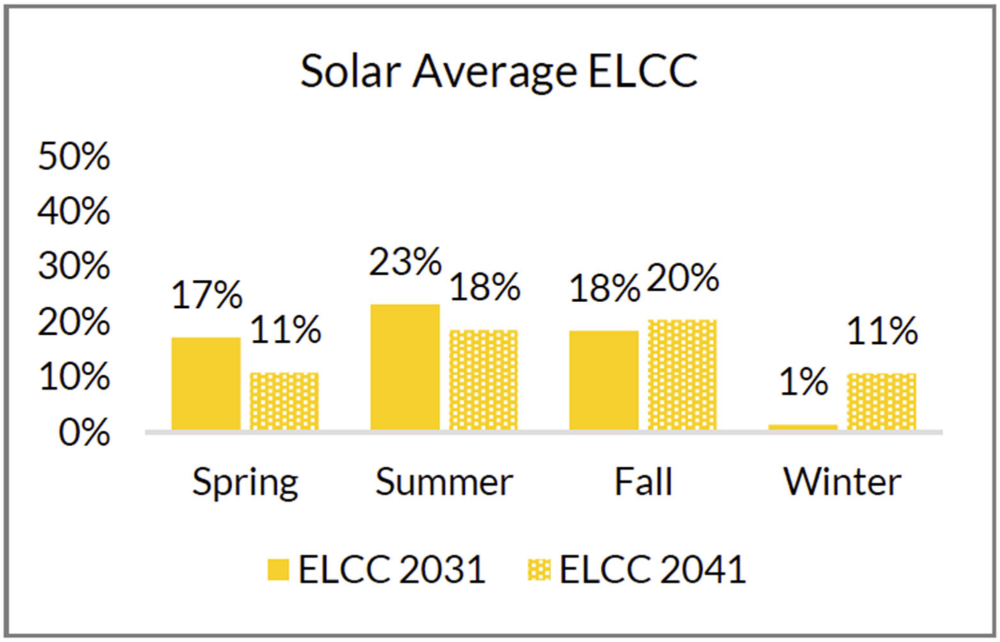
	PY23-24	F1-2025	F1-2039	2031 RRA	2041 RRA
Winter		1%	1%	2%	2%
Spring		35%	2%	2%	1%
Summer	45%	43%	4%	2%	1%
Fall		6%	5%	0%	1%
ICAP (GW)	10	19	37	54	75

Utility-scale Wind

	PY23-24	F1-2025	F1-2039	2031 RRA	2041 RRA
Winter		15%	10%	15%	13%
Spring		13%	20%	10%	9%
Summer	10%	7%	11%	12%	3%
Fall		7%	12%	14%	21%
ICAP (GW)	31	31	32	56	87

The RRA values would then become the base case assumptions. They are provided below.





2.4 Additional Questions and Comments

We also have the following additional questions and comments on the modeling files provided:

1. Fixed O&M time series for Warrick 4
    - Does the Fixed O&M time series for "Warrick: 4 Fixed O&M" include costs that will continue after the unit is offline? It looks like the Fixed O&M values for Warrick are reported even after the unit goes offline since that time series continues to have values and EnCompass will continue to see that resource since it is taken offline for maintenance, but not explicitly retired within EnCompass. Is this approach used so that any ongoing costs can be reflected in the model results?
2. Maintenance time series for FB Culley 3
    - The time series named "FB Culley:3 Maintenance" does not contain any values. We were not sure if there were supposed to be any values input for this time series.
3. Curtailments and Battery Resources
    - For modeling runs that select battery storage resources, are there large levels of curtailments for these resources because of the curtailment group order that is specified for them?
4. Market Prices
    - Were the power prices for the scenarios purchased from a third party or was the Horizons National Database used to develop them?
5. Modeling the Book Value of the Coal Resources
    - We would like to reiterate the comments that we previously submitted to CenterPoint on modeling the book value of the FB Culley units in EnCompass for

the retirement scenarios. As we noted during the December 13th workshop, it does not make sense to include remaining book value in the scenarios where coal units are retired but not in the scenarios where they are retained. In order to provide the most accurate revenue requirements comparison, they should be included in both unless CenterPoint has some reason to believe it will not recover those costs.

3 Request for Proposal ("RFP") Files

We appreciate that some of our team members received access to the RFP bid information that was used to develop the inputs for the RFP resources modeled within EnCompass. We have a couple of questions with regard to the updated pricing that CenterPoint and 1898 received from the developers:

1. Did the updated pricing information submitted by the developers for projects only reflect the incorporation of the revised Investment Tax Credit or Production Tax Credit under the IRA, or did some or all of the bidders also refresh the underlying capital costs?
2. Could CenterPoint please provide access to the RFP bid information to Ben Inskeep (binskeep@citact.org)? This request made by email to 1898 on January 3, 2023, has gone unanswered to date.

4 Stochastic Modeling Files

We would also like to submit the following questions on how the stochastic modeling will be utilized within EnCompass and ask that information be provided to stakeholders:

1. Will CenterPoint and 1898 be using the functionality within EnCompass to perform the draws on each variable or will an outside statistical package be used to determine the values for each stochastic variable across the draws?
    a. If the functionality within EnCompass will be used, what will be specified for the draw frequency, mean reversion, and deviation inputs?
    b. Will correlation be specified between any of the stochastic variables?
    c. How many draws will be run in EnCompass? Will the sampling be set to Latin Hypercube?
    d. Which distribution will be applied to each of the stochastic variables?

3-1. Provide access to supporting workbooks for:

a) Seasonal coincidence factors
b) Seasonal accreditation values for CEI South thermal units
c) A breakdown between capital and fixed O&M for CEI South thermal units

Response:

a) See the files “MISO CP model v2 fall.xlsx”, “MISO CP model v2 spring.xlsx”, “MISO CP model v2 summer.xlsx”, and “MISO CP model v2 winter.xlsx”.
b) See “SAC calculation Central North” files for each existing thermal unit and “ABB 5+6 Accreditation” for future F class CTs. Note that in some cases MISO is showing accreditation greater than the installed capacity (ICAP) of a unit but these values have been capped at ICAP in the EnCompass model.
c) The file “CONFIDENTIAL - O&M and Capex Projections for Existing Units - Draft December 20, 2022.xlsx” that was provided to stakeholders on December 20, 2022 contains this information but an updated version is being provided that addresses a couple typos that have been recently identified.

3-2. During the December meeting, CenterPoint seemed to be saying that the modeling inputs would largely be finalized after comments were received on January 6th. Because of the volume of missing data and the numerous questions we have about the data provided so far, we are concerned that there is not enough time being allocated to allow for thorough stakeholder input. Given that there is still nearly five months before CenterPoint submits its IRP, we hope that CenterPoint will provide additional flexibility to allow for continued stakeholder input after answering our questions and providing the requested information. If that is not what CenterPoint intended to communicate at the December meeting then we would welcome clarification of that as well.

Response: CEI South plans to provide updated modeling files, additional input files, and portfolios for consideration in the risk analysis to stakeholders for review and comment. CEI South plans to provide the preferred portfolio in our fourth stakeholder meeting, ahead of submitting the IRP on June 1, 2023.

3-3. How are the Inflation Reduction Act ("IRA") tax credits incorporated into the costs of new generic solar resources? It looks the time series named "PTC" is only applied as a negative $/MWH cost for the new wind resources; changes to Sections 45 and 45Y of the Internal Revenue Code now allow the Production Tax Credit to apply to solar projects.

Response:

The intent in the modeling was to include the PTC for both new solar and wind resources. This input was missing in the version of the model shared with stakeholders and has since been fixed in the model.

3-4. How is the IRA reflected for the hybrid resources? Is there an allocation for the Investment Tax Credit ("ITC") for the battery portion of the project or a full ITC applied to the project?

Response:

The ITC is used to reduce the capital cost by the full amount for storage and hybrid resources.

3-5. Did CenterPoint and 1898 considered modeling the solar hybrid resources with two distinct resources for the battery portion of the hybrid project to reflect the ability for the storage resource to not be restricted to only charging from the solar resource?

Response:

The hybrid resources were modeled as hybrids where the storage would charge from the solar. There are several options for stand alone storage and solar resources.

3-6. For the dataset named "SES - Renewable High," how did CenterPoint and 1898 determine the increase to apply to the resources modeled to reflect the RFP bids?

Response:

The high cost curves were calculated using the highest cost RFP option included within the average and escalated at the assumed inflation rate over the study period.

3-7. Are any tax credits from the Inflation Reduction Act incorporated into the capital expenditures modeled for the hydro resources?

Response:

The modeling has been updated to reduce capital costs of hydro resources based on full monetization of the ITC.

3-8. During the last stakeholder IRP meeting, it was our understanding that 1898 and CenterPoint referenced an Army Corps of Engineers Report that was used to develop the cost estimates for the resources. Is this 2013 report[1] the document that was referenced? If not, which report was used? Either way, can CenterPoint provide the spreadsheet(s) used to develop the cost inputs?

Response:

Costs escalated but consistent with the 2019 IRP were used for this analysis. See file "Hydro TA.xlsx". These costs were developed as part of the 2019 Technology Assessment – see excerpt from 2019 TA:

This Assessment assumes that low head turbines would be integrated with an existing dam that does not currently generate electricity. The turbines are assumed to be based on either the Kaplan or Bulb type technologies.

The Kaplan turbine is a propeller type, vertical axis machine in which water enters radially and exits the turbine axially. The propeller is immersed in the water flow, but is coupled to an electric generator above the turbine blades, outside of the water. Kaplan turbine designs typically include adjustable vanes and inlet gates to accommodate variable flow.

The Bulb type turbine design is also propeller driven, but water both enters and exits the turbine axially. Horizontal and vertical designs are available. On a bulb turbine, the generator is encased in a bulb shaped casing which is immersed in the water and connected to the electric distribution system above ground.

It should be noted that hydroelectric cost and performance expectations are difficult to generalize because they are entirely dependent on-site specific details. Flow characteristics and construction requirements are not consistent between different water sources and are likely inconsistent even at different points in the same source. The information presented in this Assessment is estimated based on BMcD experience and publicly available information. If hydroelectric generation technology is chosen for further development, a more detailed study shall be performed to evaluate the hydrology, geology, wildlife, and safety characteristics (in addition to cost and performance studies) of hydropower implementation.

1 - https://www.hydro.org/wp-content/uploads/2014/01/Army-Corps-NPD-Assessment.pdf

3-9. How did CenterPoint and 1898 develop the hourly shape for the hydro resources?

Response:

Historical capacity factors from Cannelton were used as a basis for the hourly shape for the hydro resources.

3-10. Will any of the resources with the name “Capacity Purchase” need adjustments to their Firm Capacity in order to reflect MISO’s new seasonal RA construct or will CenterPoint still receive the same firm capacity for these purchases in all seasons?

Response:

Capacity purchases will receive the same firm capacity in all seasons.

3-11. Are the currently approved energy efficiency programs incorporated into the model as a reduction to the load forecast? If not, how are they accounted for?

Response:

The existing income qualified energy efficiency is included in the model (IQW); These are not netted out of load outside of the model.

3-12. Would CenterPoint and 1898 be able to provide a description for some of the energy efficiency resources in EnCompass so that stakeholders can map them to the information from the Market Potential Study? (For example, the resources named “CI Enhanced,” “HER V1,” “RES High,” and “RES LowMed.”)

Response:

See file EE Resource Mapping.xlsx

3-13. Since the EnCompass inputs only seem to have three resources for C&I energy efficiency savings, will this be the only level of savings for C&I included in the modeling?

Response:

The C&I energy efficiency savings from the MPS are included as a single bundle across three different vintages (time periods). This single bundle represents an "enhanced" level of potential that was slightly higher than the MPS realistic achievable potential. This enhanced scenario was created based on feedback requests from the CAC to prioritize C&I savings, which are assumed to be less costly than savings from the residential sector. Based on the overall costs and savings, it was assumed that it would be unnecessary to breakout the overall C&I savings into additional bundles to increase the likelihood of being selected in the IRP.

3-14. Could CenterPoint and 1898 provide stakeholders with the supporting workbooks used to develop the levelized costs modeled for the new energy efficiency and demand response resources?

Response:

The workbooks used develop levelized costs were provided to the OSB on September 23, 2022.

The following link is available to download the supporting workbooks used to develop the levelized cost models for energy and demand response resources in the MPS. These provide the annual savings, annual costs, and average bundle effective useful lives (EULs), as well as estimated hourly impacts. Please download the files by February 7, 2023 when the link expires.

https://filesender.gdsassociates.com/receive/42285580-cbdd-4b7a-a8cb-5d181c18f5cf

3-15. Does the Fixed O&M time series for "Warrick: 4 Fixed O&M" include costs that will continue after the unit is offline? It looks like the Fixed O&M values for Warrick are reported even after the unit goes offline since that time series continues to have values and EnCompass will continue to see that resource since it is taken offline for maintenance, but not explicitly retired within EnCompass. Is this approach used so that any ongoing costs can be reflected in the model results?

Response:

Correct, these are potential stranded costs associated with Warrick 4.

3-16. The time series named "FB Culley:3 Maintenance" does not contain any values. CAC is not sure if there were supposed to be any values input for this time series.

Response:

At one point this input was being used for various retirement options, similar to question 3-15 about Warrick, but is currently not being used in the modeling.

3-17. For modeling runs that select battery storage resources, are there large levels of curtailments for these resources because of the curtailment group order that is specified for them?

Response:

No. The model is only curtailing storage less than .25% of the time.

3-18. Were the power prices for the scenarios purchased from a third party or was the Horizons National Database used to develop them?

Response:

The Horizon National Database was used as a starting point for the development of the power prices in the model.

3-19. Did the updated pricing information submitted by the developers for projects only reflect the incorporation of the revised Investment Tax Credit or Production Tax Credit under the IRA, or did some or all of the bidders also refresh the underlying capital costs?

Response:

We provided an opportunity for bidders to provide us updated pricing after the passage of the IRA. For Purchase options it did appear that there were pricing updates outside of tax credits and updated pricing to the underlying capital costs were made, there is less granularity behind the incremental changes in underlying capital costs that went into PPA updates. See email sent to bidders below:

"Thank you for your participation in the CenterPoint 2022 All-Source RFP. With the passage of the Inflation Reduction Act, the CenterPoint RFP team is aware that this may impact proposals that were submitted to the RFP and CenterPoint is accepting proposal updates to reflect impacts from the newly enacted law. Please submit any updates you wish to make concerning pricing or other terms affected by the Inflation Reduction Act no later than 5PM CDT, September 7th, 2022. Please submit any updates on the form attached along with any new documents via the All Source RFP website http://centerpoint2022asrfp.rfpmanager.biz/. If your proposal has not been affected by the new law, please confirm by responding directly to this email. If you have any questions or concerns, please let us know."

3-20. Could CenterPoint please provide access to the RFP bid information to Ben Inskeep (binskeep@citact.org)? This request made by email to 1898 on January 3, 2023, has gone unanswered to date.

Response:

It has been confirmed with Mr. Inskeep that he received an email on December 20, 2022 granting him access to the RFP bid information.

3-21. Will CenterPoint and 1898 be using the functionality within EnCompass to perform the draws on each variable or will an outside statistical package be used to determine the values for each stochastic variable across the draws?

a) If the functionality within EnCompass will be used, what will be specified for the draw frequency, mean reversion, and deviation inputs?
b) Will correlation be specified between any of the stochastic variables?
c) How many draws will be run in EnCompass? Will the sampling be set to Latin Hypercube?
d) Which distribution will be applied to each of the stochastic variables?

Response:

a) Yes, Encompass will be used to perform the draws. 200 iterations will be performed on monthly data. Mean reversion setting has not yet been decided (currently set to 100%). Standard deviations are based on implied uncertainty from vendor quotes. CAPEX (base, high and low) and CO2 (base, medium-high and high-high) will be assigned to iterations separately.

b) Yes, between load and NG, and NG and coal (we are still evaluating correlations between NG and CO2).

c) 200 iterations will be performed for the development of stochastic inputs. EnCompass' Latin hypercube feature will be used for the iterations.

d) Load, NG, and coal will use lognormal distributions. CAPEX and CO2 will be discrete distributions.

Comments of CAC on CenterPoint's EnCompass Modeling Files

Submitted to CenterPoint Energy Indiana South on March 17, 2023

CAC Comments on CenterPoint's EnCompass Modeling Files

Citizens Action Coalition of Indiana ("CAC") submits these comments on CenterPoint Energy Indiana South's ("CenterPoint") EnCompass modeling files that were provided to stakeholders on March 7, 2023. We appreciate the opportunity to review the latest version of modeling files. Our consultants' review of the files has led to additional questions on the inputs. We would like to submit the following feedback and questions to CenterPoint on the EnCompass modeling files and provide some comments on the Technical Workshop held on February 28, 2023.

Comments on EnCompass Modeling Files

Firm Capacity of ABB Brown Conversion

Table 1 below shows the Schedule 53 Class Averages of seasonal capacity accreditation that MISO has released for the upcoming (2023-2024) planning year. CenterPoint suggested during the February 28th workshop that it has used these values for the firm capacity that is modeled for the new thermal resources, but that does not appear to be the case especially for conversion of the CTs at AB Brown and the coal to gas conversions at FB Culley 2 and 3. Can CenterPoint confirm and explain why it used the values it used?

Table 1. MISO Schedule 53 Class Average[1]

Row Labels	Summer ISAC/ICAP	Fall ISAC/ICAP	Winter ISAC/ICAP	Spring ISAC/ICAP	Count of Units
Combined Cycle	88.17%	76.50%	80.06%	74.07%	106
Combustion Turbine 0-20MW	83.32%	82.79%	77.35%	79.01%	40
Combustion Turbine 20-50MW	87.51%	82.45%	81.64%	81.75%	118
Combustion Turbine 50+MW	91.41%	80.85%	79.78%	84.32%	174
Diesels	90.34%	85.34%	82.95%	86.77%	66
Fluidized Bed Combustion	[redacted]				8
Fossil Steam 0-100MW	81.90%	78.39%	77.60%	75.55%	52
Fossil Steam 100-200MW	[redacted]				28
Fossil Steam 200-400MW	84.15%	72.85%	76.08%	74.34%	33
Fossil Steam 400-600MW	79.45%	75.36%	80.57%	75.10%	34
Fossil Steam 600-800MW	[redacted]				24
Fossil Steam 800+MW					4
Hydro 0-30MW					14
Hydro 30+MW					8
Nuclear					17
Pump Storage					14
FleetWide Schedule 53 ISAC/ICAP	85.93%	78.48%	79.25%	78.53%	740

Demand Side Management Resources

Would CenterPoint be able to provide supporting workbooks and a description of the approach used to determine the seasonal firm capacity to model for energy efficiency and demand response resources?

[1] https://cdn.misoenergy.org/20221215%20Schedule%2053%20Class%20Average627347.pdf

Constraints on the AB Brown CTs

Was the maximum annual energy limit specified for the new CTs because the model was over-dispatching them? If not, please explain why this limit was specified.

Can CenterPoint confirm that the project constraint named "ABB7 CMin" is forcing the model to select the CT to CC conversion between 2027 and 2041 in the Reference Portfolio?

Constraint on the Northern Wind Projects

Can CenterPoint explain why the Northern wind projects were not allowed to be selected until 2033? It also looks like there is a constraint called "Wind_NT AM" that does not allow the project "Wind_NT" to be selected. It was our understanding that this represented a project from the RFP. Has CenterPoint received information that the project is no longer viable or was this not a presentation of an RFP bid and just a holdover project as CenterPoint has gone through the modeling process?

Fixed O&M and Capex Workbook

We had a few questions on the workbook named "CONFIDENTIAL O&M and Capex Projections for Existing Units – DRAFT February 8, 2023":

- Is the information for the ABB7 unit contained in this workbook? If not, would CenterPoint be able to provide that to stakeholders?
- What do the "stranded cost" rows in the workbook include?
- We compared a few of the inputs in EnCompass (FBC3 convert 2027 and FBC2 convert) to the underlying workbook and there seem to be some differences in cost starting in 2026 (FB Culley 2 convert) and 2027 (FB Culley 3 convert) that we have not been able to reconcile. What do these cost differences represent? And can we find them in the underlying workbook? If not, please provide a workbook showing how these inputs in EnCompass were calculated.
- Which EnCompass input is used to represent the Capex projections?

Recommendations from Prior Comments

We would also like to reiterate the previous comments that have been submitted to CenterPoint on renewable accreditation and the repowering of wind projects. These recommendations include modeling the Direct-LOL approach as a sensitivity instead of a base assumption and evaluating the repowering instead of retirement of CenterPoint's existing wind resources. CAC observes that Indiana Michigan Power ("I&M") recently filed a petition with the Commission associated with unspecified "technology upgrades" to Fowler Ridge that I&M has represented will maintain its 100 MW capacity offtake from this facility while lowering the PPA cost to I&M's ratepayers.[2]

[2] Cause No. 45859

Comments on Scorecard and Stochastic Modeling

We would also like to submit comments on the information provided in the Technical Stakeholder meeting held on February 2, 2023.

On the Scorecard, we would like to reiterate the comments and recommendations that were made during the call on the Reliability metrics and the coloring of the scorecard. For the Reliability metric, the "Must Meeting MISO Planning Reserve Margin Requirement in All Seasons (MW)," the Scorecard indicates that there are capacity purchases happening in the summer for each of the portfolios, but the level of the purchase varies between portfolios. Since CenterPoint is allowing the model the option to choose a capacity purchase, this metric seems confusing to present with the coloring, especially since the level of purchase amongst the portfolio is not greater than 50 MW. In addition, the scorecard already captures capacity purchases with the category "Capacity Market Purchases," so these two metrics would seem to be counting the same variable just with slightly different variations in color shading.

In addition, the "Fast Start Capability" and "Spinning Reserve" metrics indicate that the larger the MW, the greater that is for the portfolio under the coloring scheme assigned. We would recommend that the coloring be changed for these metrics to reflect whether minimum needs in these categories are met or not.

On the stochastic modeling approach, we would recommend that capital costs not be included as a stochastic model and CenterPoint use the low and high forecasts for renewable and battery storage resources as a sensitivity to the portfolios. If CenterPoint does not agree and continues to include capital costs as a stochastic variable, then we would recommend that CenterPoint include new thermal resources along with the renewable and battery storage resources. While we understand that the renewables and storage are in more portfolios, there are still several portfolios that include either the conversion of FB Culley 3 or new thermal resources ("Reference Case" and "CT Portfolio"). In addition, the risks of increased cost for thermal resources has increased since the start of the stakeholder process as inflation expectations have gone from short-term concerns to longer length expectations and more utilities announce plans to build gas units in the 2026-2028 timeframe.

We would ask that when the information is available and ready to share, that CenterPoint provide stakeholders with the stochastic inputs for the Capex and CO_2 variables.

4-1. Table 1 below shows the Schedule 53 Class Averages of seasonal capacity accreditation that MISO has released for the upcoming (2023-2024) planning year. CenterPoint suggested during the February 28th workshop that it has used these values for the firm capacity that is modeled for the new thermal resources, but that does not appear to be the case especially for conversion of the CTs at AB Brown and the coal to gas conversions at FB Culley 2 and 3. Can CenterPoint confirm and explain why it used the values it used?

Table 1. MISO Schedule 53 Class Average[1]

Row Labels	Summer ISAC/ICAP	Fall ISAC/ICAP	Winter ISAC/ICAP	Spring ISAC/ICAP	Count of Units
Combined Cycle	88.17%	76.50%	80.06%	74.07%	106
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Combustion Turbine 20-50MW	87.51%	82.45%	81.64%	81.75%	118
Combustion Turbine 50+MW	91.41%	80.85%	79.78%	84.32%	174
Diesels	90.34%	85.34%	82.95%	86.77%	66
Fluidized Bed Combustion	[redacted]	[redacted]	[redacted]	[redacted]	8
Fossil Steam 0-100MW	81.90%	78.39%	77.60%	75.55%	52
Fossil Steam 100-200MW	[redacted]	[redacted]	[redacted]	[redacted]	28
Fossil Steam 200-400MW	84.15%	72.85%	76.08%	74.34%	33
Fossil Steam 400-600MW	79.45%	75.36%	80.57%	75.10%	34
Fossil Steam 600-800MW	[redacted]	[redacted]	[redacted]	[redacted]	24
Fossil Steam 800+MW	[redacted]	[redacted]	[redacted]	[redacted]	4
Hydro 0-30MW	[redacted]	[redacted]	[redacted]	[redacted]	14
Hydro 30+MW	[redacted]	[redacted]	[redacted]	[redacted]	8
Nuclear	[redacted]	[redacted]	[redacted]	[redacted]	17
Pump Storage	[redacted]	[redacted]	[redacted]	[redacted]	14
FleetWide Schedule 53 ISAC/ICAP	85.93%	78.48%	79.25%	78.53%	740

Response:

Capacity accreditation for new thermal resources was developed using MISO posted seasonal historical class average forced outage rates (https://cdn.misoenergy.org/PY%202023%202024%20LOLE%20Study%20Report626798.pdf). Capacity accreditation for the conversion of FB Culley 2 and 3 aligns with the capacity accreditation projections for FB Culley 2 and 3 on coal as the switch to natural gas is not expected to decrease the reliability of these units. Changes to the MISO accreditation for all resource types are still ongoing as MISO is in the process of moving to the seasonal construct. On March 17, 2023 FERC has issued a notice for MISO to review their UCAP/ISAC ratio. The accreditation of new CTs and CCGTs outside of the summer months under the new SAC accreditation methodology are likely to be higher than the existing averages, not only because they are new, but also as unit owners/operators adjust to the new seasonal accreditation methodology attempting to maximize accreditation in all seasons.

It should be noted that the class averages in table 1 would need the UCAP/ISAC conversion ratio applied to them to identify the final season accreditation for each resource. The example below illustrates this for a CCGT unit.

CAC Data Request Set 4 to CEI South
CEI South 2022/2023 IRP Response
April 7, 2023

	Summer ISAC/ICAP	Fall ISAC/ICAP	Winter ISAC/ICAP	Spring ISAC/ICAP
Combined Cycle[2]	89.50%	83.80%	83.90%	81.20%

UCAP/ISAC Ratio[3]	1.049	1.078	1.059	1.087

Final Accreditation	93.9%	90.3%	88.9%	88.3%

1 https://cdn.misoenergy.org/20221215%20Schedule%2053%20Class%20Average627347.pdf

2 https://cdn.misoenergy.org/20230328%20Schedule%2053%20Class%20Average_Posted627347.pdf

3 https://cdn.misoenergy.org/202303281500%20UCAP%20ISAC%20Ratio%20for%20PY23-24627342.pdf

4-2. Provide supporting workbooks and a description of the approach used to determine the seasonal firm capacity to model for energy efficiency and demand response resources?

Response: The EE/DR MPS models provided annual estimates of annual savings as well as summer peak capacity impacts. For IRP modeling purposes these annual estimates were provided at an 8,760 level. For EE, we determined the annual savings by end-use, and then used the 8,760 end-use load shapes from the NREL dataset (for Indiana) to break out the annual energy savings at the hourly level. Inevitably, the result of the hourly disaggregation from the NREL load-shapes did not produce an identical summer peak reduction that was equivalent to the summer peak capacity savings from the MPS (which was determined from deemed savings algorithms, technical reference manuals, evaluation studies, etc.). To help align the hourly IRP inputs with the estimated summer peak reductions in the MPS, we forced in the MPS summer peak capacity impacts over a three hour window (including HE 16) for all peak days in July/August. Any difference in savings during that window between the original hourly estimates and the MPS-adjusted impacts were spread out evenly over all remaining hours so that the overall annual hourly shape was consistent. Any non-summer seasonal impacts can be derived from this resulting shape. To account for MISO's shift to a seasonal accreditation construct, accreditation for EE in the different seasons was determined based on the program's output compared to seasonal peak hours based on CenterPoint's load shape.

For DR, the MPS-determined peak impacts were included in the same 3-hour window during peak days in July/August as EE. Surrounding hours were used to show snapback so that the overall energy impacts remained zero.

The hourly approach is consistent with what GDS provided to CNP for prior IRP (except that there are additional end-use load shapes now that they are based on the NREL data, and not our own building simulation models).

The supporting file “Confidential IRP Template v.FINAL – Seasonal Accreditation” is being provided in response to this DR.

For other supporting workbooks please see the files listed below that were provided in the response to CAC DR3-14.

CAC DR2 – EE Resource Mapping

CAC DR 4 - Commercial_Annual_IO_v.03

CAC DR 4 – Residential_Annual_IO_v.04_$70 Mwh

DR CenterPoint Summary Tables v2

IRP EE Summary Template v.FINAL

4-3. Was the maximum annual energy limit specified for the new CTs because the model was over-dispatching them? If not, please explain why this limit was specified.

Response:

The CTs have an annual hours limitation due to their air permit. The 40% annual capacity factor limit was included to make sure that our modeling respected these permit limitations.

4-4. Can CenterPoint confirm that the project constraint named "ABB7 CMin" is forcing the model to select the CT to CC conversion between 2027 and 2041 in the Reference Portfolio?

Response:

The models provided as part of the tech to tech were set up in preparation for the risk analysis; the reference case portfolio was based on results from the reference case optimization. During the optimization process and the selection of the reference case portfolio by the model, the constraints around AB Brown were set up to force EnCompass to choose to either continue AB Brown 5/6 as CTs or to convert the unit to AB Brown 7. Since the reference case optimization selected the CCGT conversion, that option was included as part of the portfolio carried into the risk analysis.

4-5. Can CenterPoint explain why the Northern wind projects were not allowed to be selected until 2033? It also looks like there is a constraint called "Wind_NT AM" that does not allow the project "Wind_NT" to be selected. It was our understanding that this represented a project from the RFP. Has CenterPoint received information that the project is no longer viable or was this not a presentation of an RFP bid and just a holdover project as CenterPoint has gone through the modeling process?

Response:

The models provided as part of the tech to tech were developed for the risk analysis. It is not an optimization run. Optimization runs were conducted for all 5 scenarios. The reference case was pulled into the risk analysis based on optimized results. Other portfolios were developed with the aid of optimization, but locked down prior to conducting the risk analysis. The Wind_NT was not selected during optimizations, and therefore was not included in portfolios that are being carried forward into risk analysis.

4-6. We had a few questions on the workbook named "CONFIDENTIAL O&M and Capex Projections for Existing Units – DRAFT February 8, 2023":

a) Is the information for the ABB7 unit contained in this workbook? If not, would CenterPoint be able to provide that to stakeholders?
b) What do the "stranded cost" rows in the workbook include?
c) We compared a few of the inputs in EnCompass (FBC3 convert 2027 and FBC2 convert) to the underlying workbook and there seem to be some differences in cost starting in 2026 (FB Culley 2 convert) and 2027 (FB Culley 3 convert) that we have not been able to reconcile. What do these cost differences represent? And can we find them in the underlying workbook? If not, please provide a workbook showing how these inputs in EnCompass were calculated.
d) Which EnCompass input is used to represent the Capex projections?

Response:

a) No. Please see the file "CenterPoint 2022 IRP Technology Assessment (Combined) - Draft December 20, 2022" that was provided to stakeholders on December 20, 2022.
b) Stranded costs include the undepreciated value of assets that will no longer be used and useful following the closure of the units.
c) Please see CONFIDENTIAL 2023.04.06 - FBC Revenue Requirement.xlsx. This adds in costs associated with a NG pipeline to the fixed costs.
d) Ongoing O&M and capital associated with the gas conversion are included in the "CONFIDENTIAL O&M and Capex Projections for Existing Units – DRAFT February 8, 2023" workbook. Capital and O&M cost are included in the “The Fixed O&M” input in Encompass.

3.1 It's not clear to us what assumptions CenterPoint has adopted for modeling solar, wind, and battery storage. We understand from the earlier slide decks that you relied on the results from your RFPs, refreshed the bids, and then applied the NREL ATB cost decline assumptions. But in those initial RFP bids that you used as a starting point, did any of the respondents assume that the projects were to be located in an energy community or not?

Response:

Near-term modeling of wind, solar, and storage relied on using PPA prices from the RFP; all potential tax credits which RFP projects would qualify for would be included in the PPA prices provided. Beyond the near-term modeling and executable window for projects received as part of the RFP, site-specific assumptions to include energy community adders for the PTC were not included. However, as part of the sensitivity analysis of the reference case and portfolio decisions, various resource capital costs and tax credit qualification sensitivities were performed to determine the impact of these changes on future resource decisions.

3.2 Are the assumptions CenterPoint made about NOx allowance limits, projected NOx emissions for your units, and costs consistent with the updated rules that just came out this week? If not, will CenterPoint be updating its assumptions to reflect this rule? Does CenterPoint anticipate that the final rule will significantly change any of its results?

Response: After preliminary review, Indiana's allocation of NOx allowances does not look significantly different from the most recent CSAPR allocation which was modeled in the current IRP. We will continue to review, but do not expect the updated Good Neighbor SIP allowance allocations to significantly differ from our assumptions in the IRP.

3.3 Cost associated with other environmental regulations:

a) Has the CCR Extension at AB Brown been ruled on yet? How is that cost potential being modeled?

b) Cost of FGD wastewater system at Culley 3 – is that assumed to be a sunk cost? Are there ongoing O&M costs? If so, what are those and where are they being modeled?

c) Other Clean Water Act costs for Compliance at Culley 3 – What are the projected costs associated with compliance and where are those being modeled? Are the capital costs separated from the O&M costs?

Response:

a) CEI South has received conditional approval on the CCR extension at AB Brown but the EPA is yet to finalize. Since these are fixed costs and are consistent across all portfolios they do not impact IRP modeling.

b) Yes. Ongoing O&M costs for the FGD wastewater system are estimated to be $50,000 in year one and escalate 2.3% annually. This is included in the fixed costs in the modeling.

c) All O&M and capex assumptions are shown in the O&M and Capex projection spreadsheet provided to stakeholders on March 7th.

3.4 Is 2023 the final date for Warrick 4 retirement or is there a possibility that the contract will be extended?

Response: Currently CEI South expects to exit out of the Warrick 4 Joint Operating Agreement (JOA) at the end of 2023; however, CEI South continues to discuss with Alcoa the possibility of contract extension.

3.5 Did you do any modeling with lower costs for storage? Do you know what assumptions you would need for battery storage for more of it to be selected by the model (i.e., how much do storage costs have to fall below what CenterPoint assumed for the model to select more battery storage earlier in the planning period).

Response:

Yes. Storage costs were varied within the scenarios and within the probabilistic model to reflect higher and lower costs relative to the base case. Additionally, various sensitivity analysis is being performed to test the impact of different costs for battery storage, along with sensitivities associated with how much accreditation a battery may receive in the future from MISO.

3.6 Has CenterPoint considered the possibility of securitization in its modeling both for retirement of Culley 3 and replacement with alternatives?

Response: No legislation currently exists that allows for securitization of any assets beyond the A.B. Brown units.

3.7 Did CenterPoint figure out why the NPVRR of the Reference case, which is by far the most carbon intensive of any case, still has the lowest cost under the Decarbonization/Electrification and High Regulatory scenarios that both include a Carbon Price?

Response:

The NPVRR of the reference case under different scenarios still benefits from the ability to dispatch an efficient gas combined cycle and sell energy into the market to lower the portfolio NPVRR under scenarios where there is a carbon price.

Sierra Club Data Request Set 3 to CEI South
CEI South 2022/2023 IRP Response
April 7, 2023

3.8 U.S. Energy Information Administration just published its Annual Energy Outlook this week - the EIA's natural gas price current forecast differed from its forecast last year in that it is projects (1) slightly higher prices in the near term (i.e., this year into next), followed by lower gas prices over the next few years. Has CenterPoint received Spring 2023 gas price forecasts? If not, is planning to update its gas price assumptions using spring 2023 numbers?

Response: No. Based on stakeholder feedback, CEI South updated the gas price forecast following our first stakeholder meeting in the summer of 2022 to fall forecasts from various venders. Gas prices have since come down dramatically. CEI South is including probabilistic modeling that is designed to capture the effects of gas price volatility.

3.9 What utilization levels does CenterPoint model or assume for Culley 3 after it is converted to operate on gas? Generation levels for coal + gas combined (pre-conversion) look very similar to generation levels for just gas after the conversion. Does CenterPoint assume the capacity factor for Culley 3 on gas will be similar to Culley 3 on coal?

Response:

The capacity factors for Culley 3 on gas are much lower than the capacity factor for Culley 3 on coal.

3.10 Replace FB Culley 3 with Solar and Storage has higher market purchases – Did CenterPoint test any sensitivities where it hard-coded in more renewables to reduce the purchases to understand how it would impact the cost to reduce purchases down to the levels seen in the other scenarios?

Response:

Yes. Several portfolios, including the diversified renewables portfolio, were tested where additional renewables were included in the portfolio to reduce market purchases.

3.11 Reference case with CCGT conversion in 2027 has really high market sales – Did CenterPoint test sensitivities where it assumed lower market prices or capped market sales? How much of the NPVRR delta between scenarios can be explained by the large amount of market sales.

Response:

In order to avoid portfolios that were developed due to excess market sales, market sales were capped during the portfolio development step of the analysis. The Reference case portfolio does sell more energy into the market than other portfolios and relies less on market purchases for energy. Market purchases and sales percentages are included in the scorecard and are being analyzed to determine potential risks for different portfolios.

3.12 Convert FBC3 to Natural gas by 2027- Why are there capacity purchases in 2025-2028 when the Company doesn't have a capacity shortfall?

Response: In securing capacity for the 2023/2024 MISO Planning Year to bridge the gap between the coal-fired unit shutdowns and exit and the CT and renewable resources, CEI South secured several bilateral capacity agreements. One contract in particular was only willing to negotiate a multiyear bilateral contract and, with the concern of limited capacity, availability, CEI South entered into this agreement.

3.13 Diversified Renewables scenario: Did CenterPoint do any analysis to understand how much its renewable cost assumptions would have to fall for the scenario to be economically competitive with some of the others?

Response:

The diversified renewables portfolio was created for the risk analysis. It is not a scenario. CEI South did model scenarios where prices for renewable and storage resources were lower relative to base case.

IRP Public Stakeholder Meeting

April 26, 2023

Welcome and Safety Share

Richard Leger
Senior Vice President Indiana Electric

April 26, 2023

Safety Share
Family Emergency Plan

The National Safety Council recommends every family have an emergency plan in place in the event of a natural disaster or other catastrophic event. Spring is a great time to review that plan with family members. Have a home and car emergency kit. The Federal Emergency Management Agency says an emergency kit should include one gallon of water per day for each person, at least a three-day supply of food, flashlight and batteries, first aid kit, filter mask, plastic sheeting and duct tape, and medicines. Visit the FEMA website for a complete list. The emergency plan also should include:

- A communications plan to outline how your family members will contact one another and where to meet if it's safe to go outside
- A shelter-in-place plan if outside air is contaminated; FEMA recommends sealing windows, doors and air vents with plastic sheeting
- A getaway plan including various routes and destinations in different directions
- Also, make sure your first aid kit is updated.

For more information, visit the National Safety Council website at www.nsc.org

Meeting Guidelines, Agenda, and Follow-Up Information

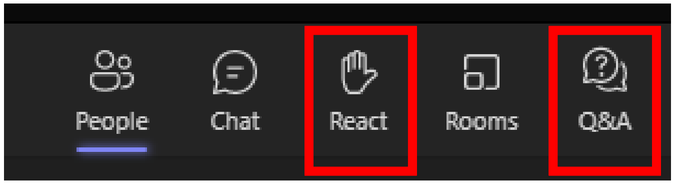
Matt Rice
Director, Regulatory and Rates

Agenda

Time	Topic	Presenter
12:00 – 1:00	Sign-in/Refreshments	
1:00 – 1:10	Welcome, Safety Message	Richard Leger, CenterPoint Energy Senior Vice President Indiana Electric
1:10 – 1:30	Follow Up Information From Third IRP Stakeholder Meeting	Matt Rice, CenterPoint Energy Director Regulatory & Rates
1:30 – 2:00	Preferred Portfolio	Matt Rice, CenterPoint Energy Director Regulatory & Rates
2:00 – 2:25	Risk Analysis Modeling and Portfolios	Drew Burczyk, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
2:25 – 2:45	Risk Analysis Scorecard	Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
2:45 – 3:00	Next Steps	Matt Rice, CenterPoint Energy Director Regulatory & Rates

Meeting Guidelines

1. Please hold most questions until the end of each presentation. Time will be allotted for questions following each presentation. (Clarifying questions about the slides are fine throughout)
2. For those on the webinar, please use the “React” feature in Microsoft Teams (shown at the bottom of this page) to raise your hand if you have a question and we will open your (currently muted) phone line for questions within the allotted time frame. You may also type in questions in the Q&A feature in Microsoft Teams.
3. The conversation today will focus on resource planning. To the extent that you wish to talk with us about other topics we will be happy to speak with you in a different forum.
4. At the end of the presentation, we will open the floor for “clarifying questions,” thoughts, ideas, and suggestions.
5. There will be a parking lot for items to be addressed at a later time.
6. CenterPoint Energy does not authorize the use of cameras or video recording devices of any kind during this meeting.
7. Questions asked at this meeting will be answered here or later.
8. We will do our best to capture notes but request that you provide written feedback (concepts, inputs, methodology, etc.) at IRP@CenterPointEnergy.com following the meeting. Additional questions can also be sent to this e-mail address. **We appreciate written feedback within 10 days of the stakeholder meeting.**
9. The Teams meeting will be recorded only to ensure that we have accurately captured notes and questions from the meeting. The public meetings are not transcribed, and the recordings will not be posted to the website. However, Q&A summaries of our public meetings will be posted on www.CenterPointEnergy.com/irp.



Commitments for 2022/2023 IRP

CenterPoint Energy

- ✓ Utilize an All-Source RFP to gather market pricing & availability data
- ✓ Utilize EnCompass software to improve visibility of model inputs and outputs
- ✓ Will include a balanced risk score card. Draft to be shared at the first public stakeholder meeting
- ✓ Will conduct technical meetings with interested stakeholders who sign an NDA
- ✓ Evaluate options for existing resources
- ✓ Will strive to make every encounter meaningful for stakeholders and for us
- ✓ The IRP process informs the selection of the preferred portfolio
- ✓ Work with stakeholders on portfolio development
- ✓ Will test a wide range of portfolios in scenario modeling and ultimately in the risk analysis
- ✓ Will conduct a sensitivity analysis
- ✓ The IRP will include information presented for multiple audiences (technical and non-technical)
- ✓ Will provide modeling data to stakeholders as soon as possible
  - ✓ Draft Reference Case results – October 4th to October 31st
  - ✓ Draft Scenario results – December 6th to December 20th
  - ✓ Full set of final modeling results - March 7th to March 31st*

* Stochastic files to be provided following the final stakeholder meeting

2022/2023 IRP Process

CenterPoint Energy

Stakeholder input is provided on a timely basis throughout the process, with meetings held in August, October, December, and April

1. Conduct an All Source RFP
2. Create Objectives, Risk Perspectives and Scorecard Development
3. Create Reference Case Assumptions and Scenario Development
4. Portfolio Development Based on Various Strategies, Utilizing Optimization to Create a Wide Range of Portfolios With Input From All Source RFP Data
5. Portfolio Testing in Scenarios, Focused on Potential Regulatory Risks
6. Portfolio Testing Using Probabilistic Modeling
7. Conduct Sensitivity Analysis
8. Populate the Risk Scorecard that was Developed Early in the Process and Evaluate Portfolios
9. Select the Preferred Portfolio

2022/2023 Stakeholder Process

August 18, 2022	October 11, 2022	December 13, 2022	April 26, 2023
• 2022/2023 IRP Process • Objectives and Measures • Encompass Software • All-Source RFP • MISO Update • Environmental Update • Draft Reference Case Market Inputs & Scenarios • Load Forecast Methodology • DSM MPS/ Modeling Inputs • Resource Options	• All-Source RFP Results and Final Modeling Inputs • Draft Resource Inputs • Final Load Forecast • Scenario Modeling Inputs • Portfolio Development • Probabilistic Modeling Approach and Assumptions • Draft Reference Case Modeling Results	• Draft Scenario Optimization Results • Draft Portfolios • Final Scorecard and Risk Analysis • Final Resource Inputs[1]	• Final Reference Case Modeling • Probabilistic Modeling Results[2] • Risk Analysis Results • Preview the Preferred Portfolio

[1]Provided results to those with an NDA by December 20, 2022 Updated modeling results were provided to stakeholders on March 7, 2023
[2] Stochastic files to be provided following the final stakeholder meeting

Stakeholder Collaboration

During this IRP cycle we have had additional communication with stakeholders through a series of tech-to-tech meetings. These have allowed additional opportunity for stakeholders to provide helpful input and participate in this process

Tech to Tech Modeling Feedback		
Meeting Dates	**General Notes and Feedback**	**Data Requested**
October 5th, 2022	• Discussed model inputs and assumptions • Evaluated model constraints • Discussed CO_2 forecast assumptions	• Stochastic modeling information • CO_2 price curves
October 31st, 2022	• Discussed Energy Efficiency and Demand Response model inputs • Discussed optimization of conversion options	• Reference case model outputs • Energy Efficiency and Demand Response model inputs
December 7th, 2022	• Reviewed optimized portfolios • Discussed assumptions surrounding optimized model outputs and portfolio buildouts	• Commodity forecasts • RFP PPA and Purchase pricing inputs • Stochastic results • Draft EnCompass model
February 28th, 2023	• Gathered input before running the risk analysis • Discussed accreditation, capital, and O&M projection updates • Evaluated final approach for the risk analysis	• Final capital cost curve estimates • Final IRP resource accreditation • Final near term PPA pricing

Stakeholder Feedback

Stakeholder Feedback	Response
Stakeholder request for continued dialogue following the public stakeholder meeting in December	Held a tech-to-tech meeting on February 28, 2023, to provide updated modeling files, additional input files, and portfolios for consideration in the risk analysis to stakeholders for review and comment
Include full monetization of Investment Tax Credit (ITC) for hydro resources	Included
Include the same style energy and capacity graphs that were included in the final tech-to-tech meeting when displaying risk analysis portfolios	Included
Beyond the near-term modeling, did you include site-specific assumptions to include energy community bonus for the Production Tax Credit and ITC	CEI South ran various resource capital costs and tax credit qualification sensitivities to determine the impact of these changes on future resource decisions

Stakeholder Feedback

Stakeholder Feedback	Response
Please evaluate a portfolio with hydro electric	Hydro was not selected in any of the 5 optimized modeling runs. Several portfolios were considered with hydro. These portfolios resulted in higher costs and were screened out of the risk analysis
Color coding in the score card is not helpful	The color coding is assigned by Excel based on rank order. We believe it is useful in helping discern a lot of information quickly. The scorecard is just a tool used to assimilate trade offs; we use judgement and reason to select a preferred portfolio
Capital costs should not be varied stochastically	An alternate process was used for capital and CO_2. The process will be described today
Adjust the scorecard to include near and long-term energy purchases/sales	Adjusted

Q&A

Preferred Portfolio

Matt Rice

2022/2023 IRP Background

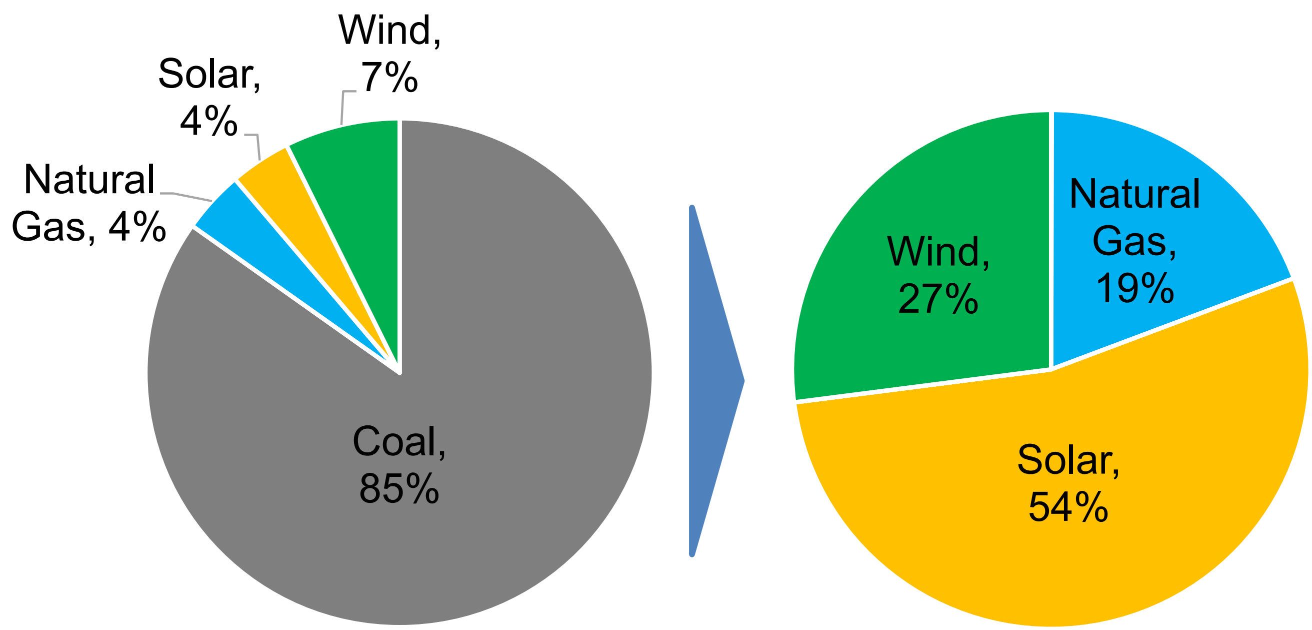
- Since the 2020 IRP, there has been unprecedented change in multiple areas that effect generation planning:
  - Disruption in the solar market (supply chain issues stemming from COVID, threat of tariffs, and an investigation by the Commerce Department on forced labor in China) that has driven costs much higher than expected
  - Dispatchable generation is rapidly retiring and replaced with intermittent generation, causing a capacity shortage in MISO. The market reached the max price of Cost of New Entry (CONE) for the 2022/2023 planning year
  - Passage of the Inflation Reduction Act (IRA) which accelerated the demand for renewables projects at a time of supply chain constrains is fueling near term price increases
  - Rising energy costs that have helped drive high inflation throughout the economy
  - Fundamental changes to MISO rules and mechanisms (to ensure reliability for the worst week across four seasons rather than planning for the one peak hour of the year in summer) results in lower capacity accreditation for solar in the long term, while wind has benefited from these changes
  - EPA continues to ratchet down on air emissions, targeting coal

Why Was This Portfolio Chosen?

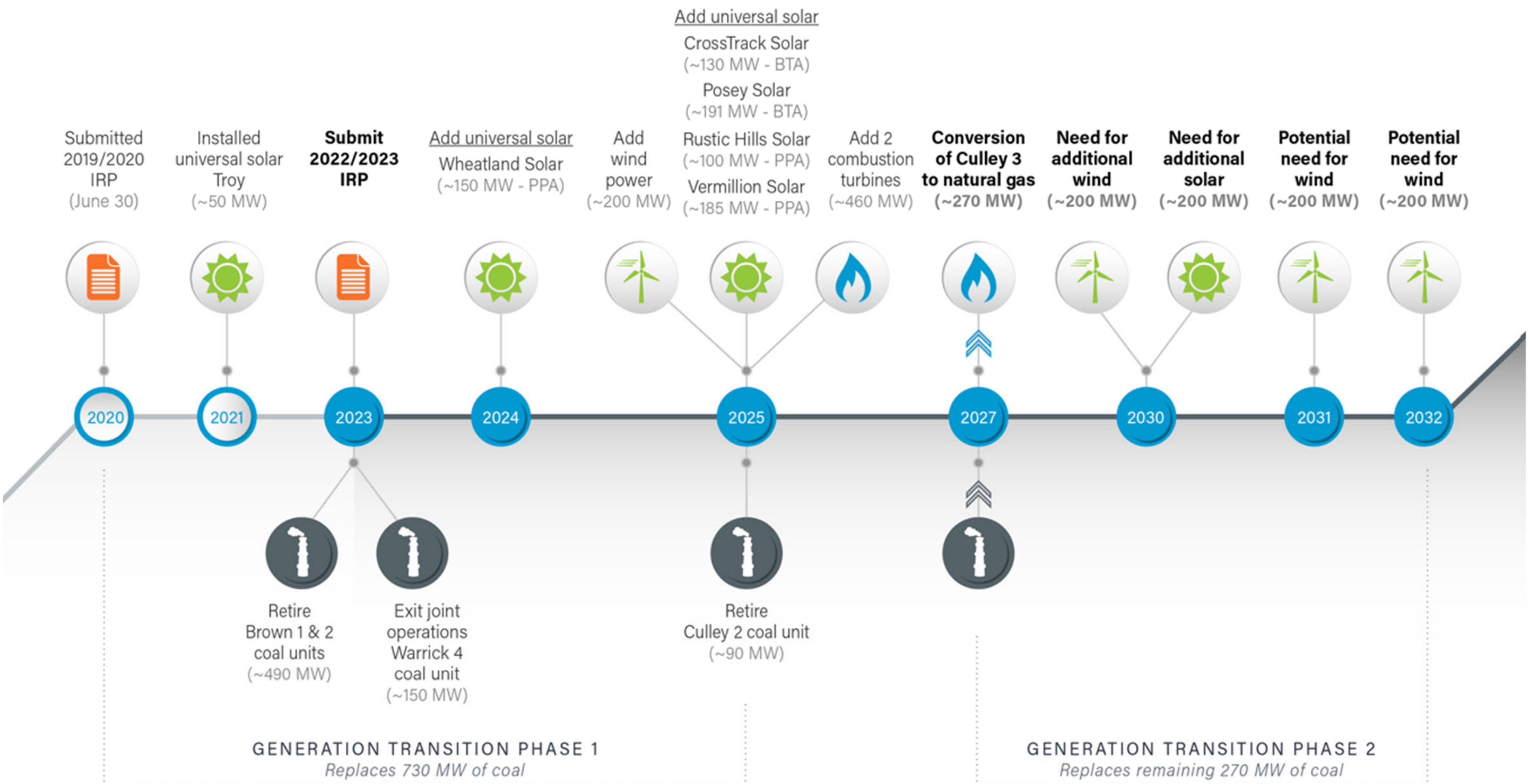
The preferred portfolio converts FB Culley 3 from coal to natural gas by 2027 and adds 200 MW of solar and 200 MW of wind by 2030. An additional 400 MW of wind is called for by 2032.

- **Preferred Portfolio Benefits**
  - Maintains reliability, preserving 270 MW of capacity
  - Saves customers nearly $80 million vs continuation of F.B. Culley 3 on coal
  - Lowers CO_2 output by more than 95%
  - Avoids future customer cost risk by preserving interconnection at Culley 3
  - Preserves tax base in Warrick County
  - Maintains ability to ramp if needed for economic development

2023 to 2030 Energy Production



CenterPoint Energy IRP Preferred Portfolio[1]



IRP = Integrated Resource Plan
MW = Megawatt
BTA = Build Transfer Agreement/Utility Ownership
PPA = Power Purchase Agreement

[1] Subject to change based on availability and approval

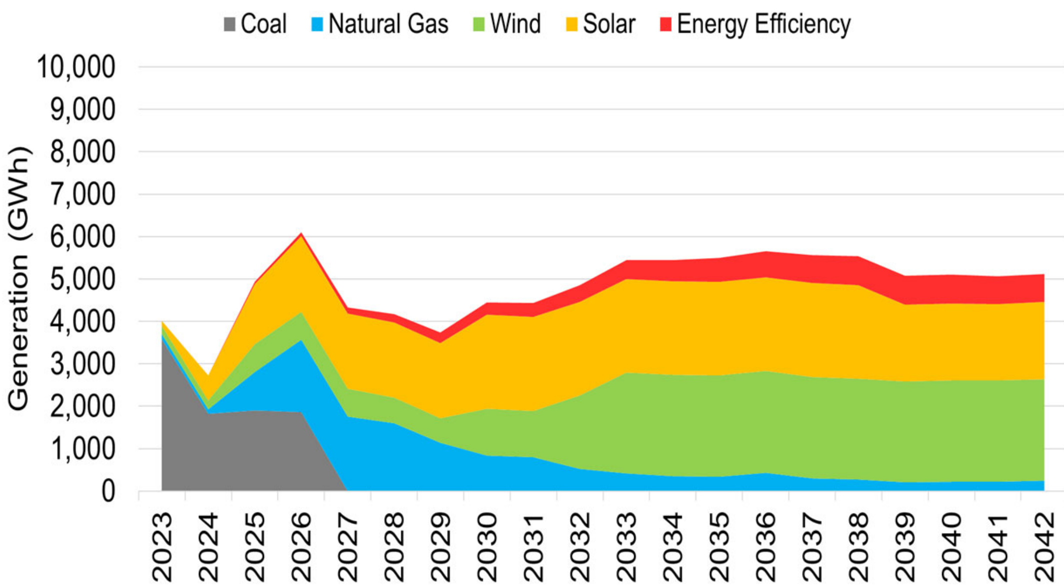
Benefits of FB Culley 3 Conversion

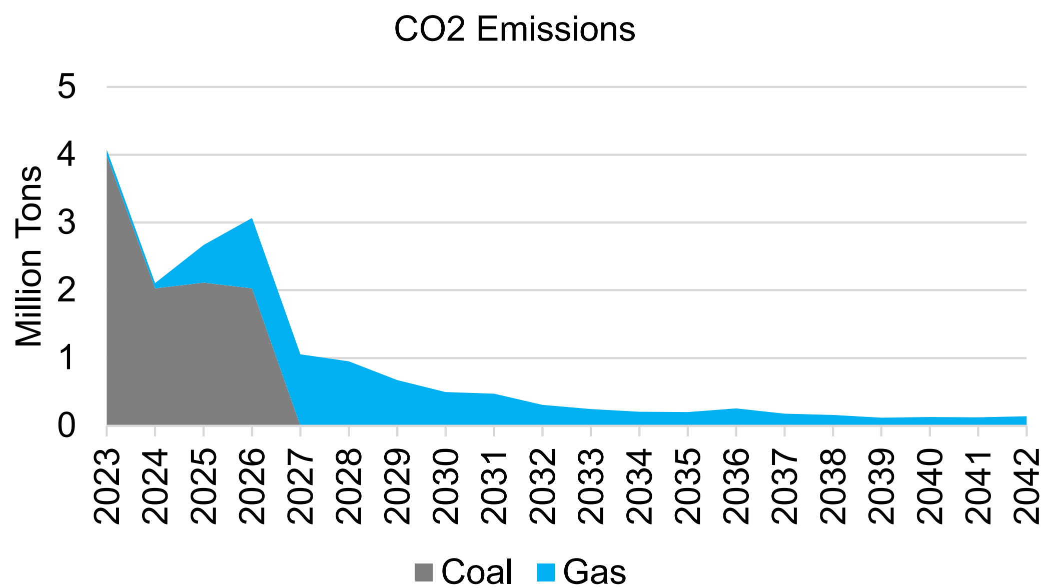
- Reliability and affordability
  - Dispatchable resource supports continued transition to renewable energy by providing energy during peak hours where energy prices are at their highest
  - Hedge against future capacity costs that are expected to remain high in the MISO market
  - Low up front capital cost, reduced O&M and reduced fuel cost results in savings for customers when compared to continuing to run on coal
  - Able to run during times of long duration renewables drought
  - More certainty on future accreditation
- CO_2 emissions nearly the same to storage and renewable portfolios with reduced SO_2 and NO_x emissions
  - Runs approx. 1% of the time
- Provides off ramp in the future
  - Allows for new alternatives to maintain reliability when they become available and affordable in the future
- Maintains existing resource
  - Maintain resource interconnection, reducing future cost and timing risk with MISO interconnection queue
  - Reduces stranded asset cost risk
- Resource diversity
  - Resilient\Diverse firm gas supply to different plants to supporting peaking operation
  - Reduced firm gas cost due to 8-12 hour start time
- Provides ancillary services for stability
- Maintains tax base in community

Preferred Portfolio Annual Generation and Emissions

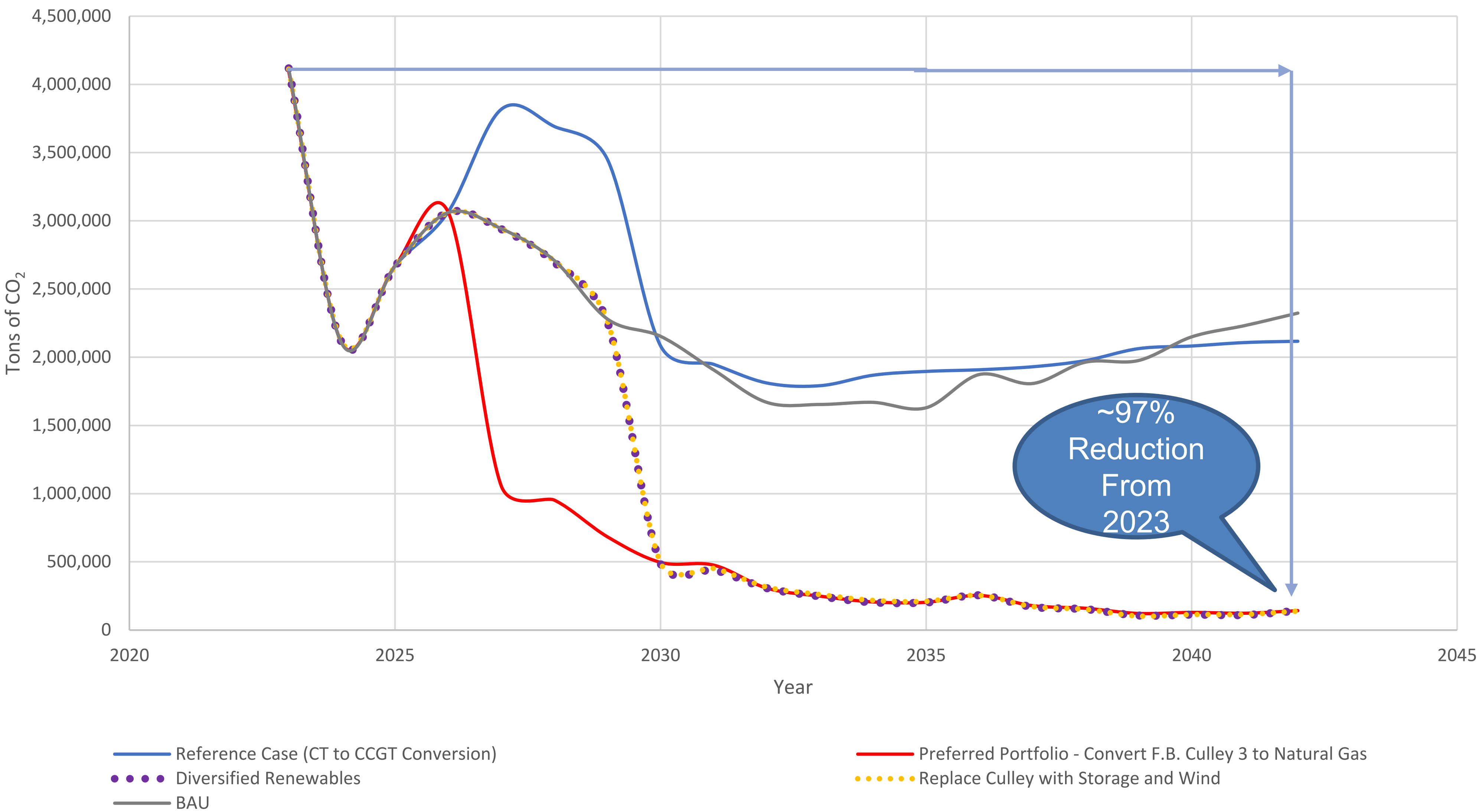
CenterPoint Energy

- Generation will shift from coal to renewables and gas in the near term with a long-term shift from natural gas to mostly renewables
- By 2030 80% of energy produced will be from wind and solar resources
- From 2023 to 2030 CO_2 emissions drop by 88% and 97% by the end of the period



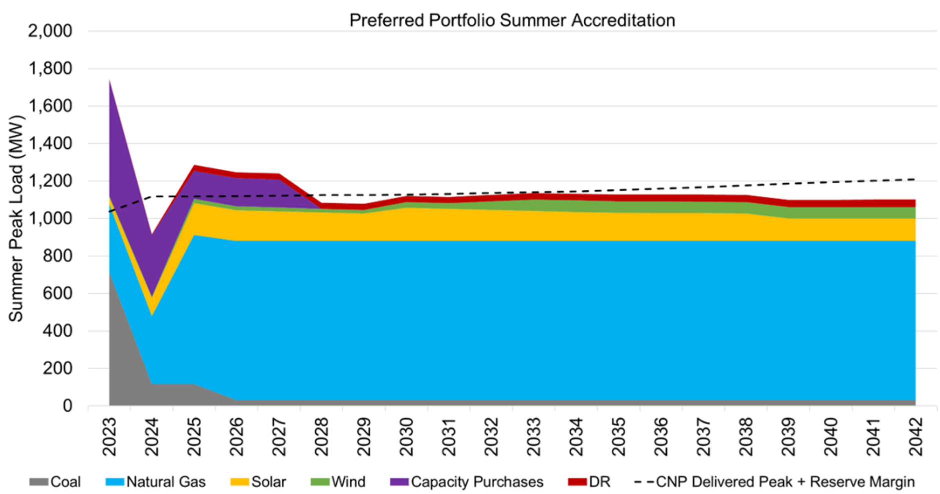


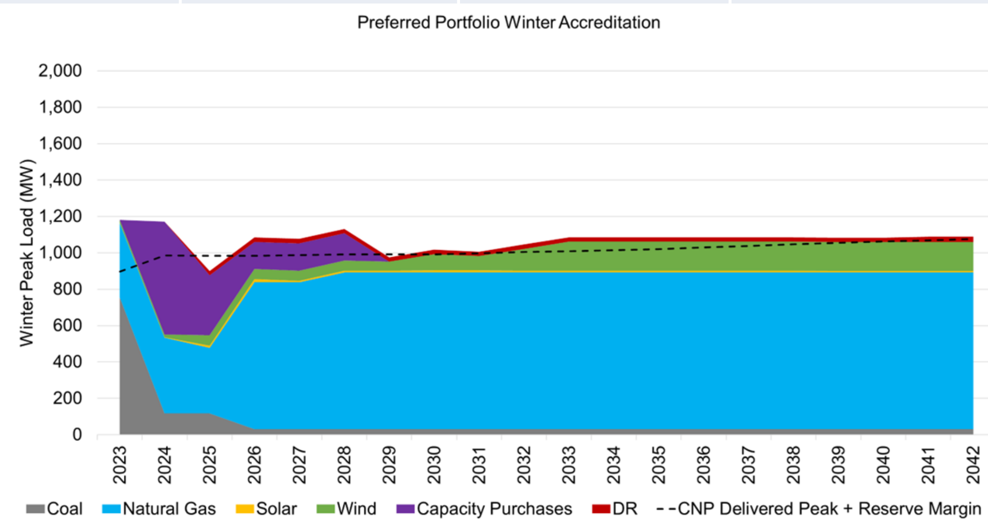
Portfolio CO_2 Emissions



Preferred Portfolio Additions and Retirements

2030-2031 Planning Year	2030-2031 Summer UCAP (MW)	Summer Accreditation %	% Summer UCAP	2030-2031 Winter UCAP (MW)	Winter Accreditation %	% Winter UCAP
Coal	30	94%	2%	30	95%	3%
Natural Gas	851	94%	76%	862	95%	85%
Solar	176	17%	16%	10	1%	1%
Wind	31	7%	3%	90	20%	9%
DR	33	100%	3%	24	100%	2%
Total Resources	1,121	N/A	100%	1,016	N/A	100%





Demand Side Resources in the Preferred Portfolio[1]

- Consistent with the 2019 IRP, the framework for the 2021-2023 EE Plan was modeled at a savings level of 1.2% of retail sales adjusted for an opt-out rate of 77% of eligible load.
  - CEI South used the realistic achievable potential identified in a Market Potential Study (MPS) as a starting point and worked closely with stakeholders on their suggested process
  - Residential sector savings were segmented into two tiers (High-Cost & Low/Mid Cost) due to stakeholder and CEI South concerns that aggregated residential sector bundles would not get selected
  - To maximize the amount of residential energy efficiency that could be selected, bundles were redrawn, shifting higher cost measures from Tier 1 into Tier 2
  - This process was utilized instead of altering EE pricing utilizing the standard deviations described in prior stakeholder meetings. Results were built into all portfolios for risk analysis modeling
  - Income Qualified Weatherization (IQW), the transition of Legacy DLC (Summer Cycler), and the Industrial DR programs were applied to all scenarios[2]

Vintage	Portfolio Selection
Vintage 1 2025 - 2027	DR Legacy - 2023
	DR Industrial
	C&I Enhanced
	HER
	IQW
	Res LowMed
Vintage 2 2028 - 2030	C&I Enhanced
	IQW
	HER
	Res LowMed
	DR CI Rates
Vintage 3 2031 - 2042	C&I Enhanced
	DR CI Rates
	IQW
	Res LowMed

[1]CEI South's DSM programs have been approved by the Commission and implemented pursuant to various IURC orders over the years

[2]CEI South is currently in discussion with a C&I aggregator to help realize the Industrial DR included in the preferred portfolio

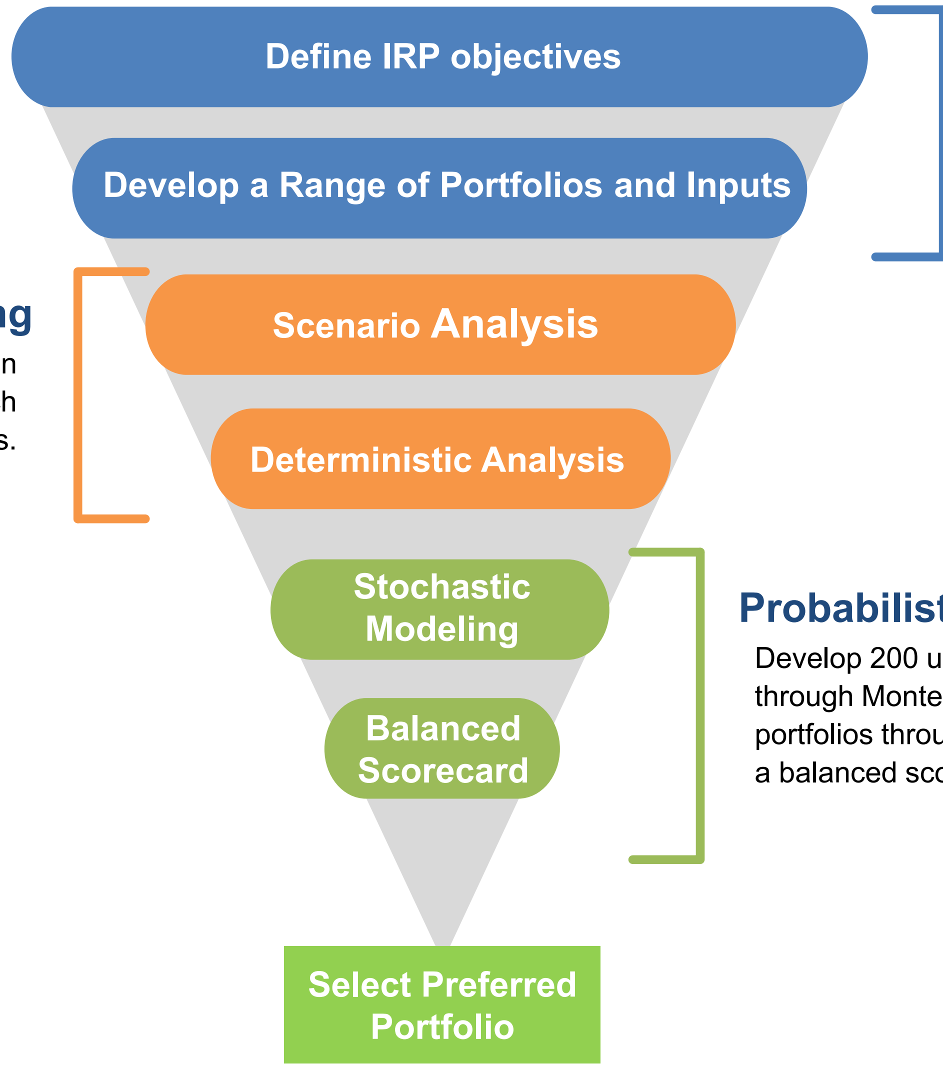
Q&A

Risk Analysis Modeling and Portfolios

Drew Burczyk, 1898

IRP Portfolio Evaluation and Selection Process

CenterPoint Energy



Initial Modeling Phase

Outline the customer requirements and project options/constraints within the model.

Deterministic Modeling

Optimize the least cost capacity expansion plan for each portfolio. Run hourly dispatch modeling on all portfolios.

Probabilistic Modeling

Develop 200 unique families of modeling inputs through Monte Carlo simulation. Run selected portfolios through 200 families of inputs to achieve a balanced scorecard.

Probabilistic Modeling Approach

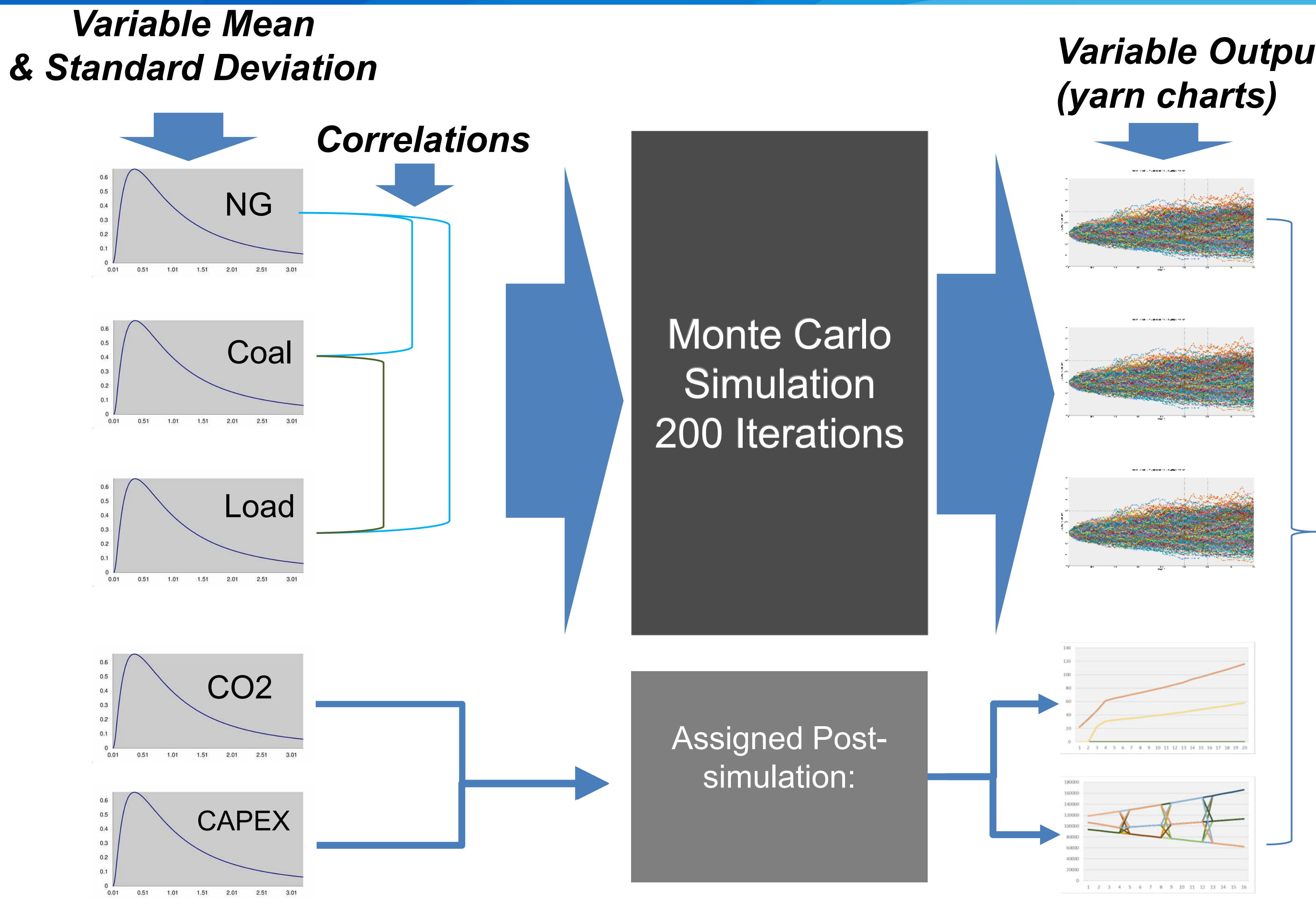
CenterPoint Energy

Objective: Utilize stochastic analysis around key IRP inputs to measure uncertainty around power supply portfolio costs

<u>Two Purposes:</u>

1. Evaluate results of stochastic inputs analysis to inform on what inputs to use for various scenarios; and
2. Stochastically develop 200 “families” of correlated inputs to run through PCM – result will be probability distribution around power supply costs

Risk Analysis Process Overview

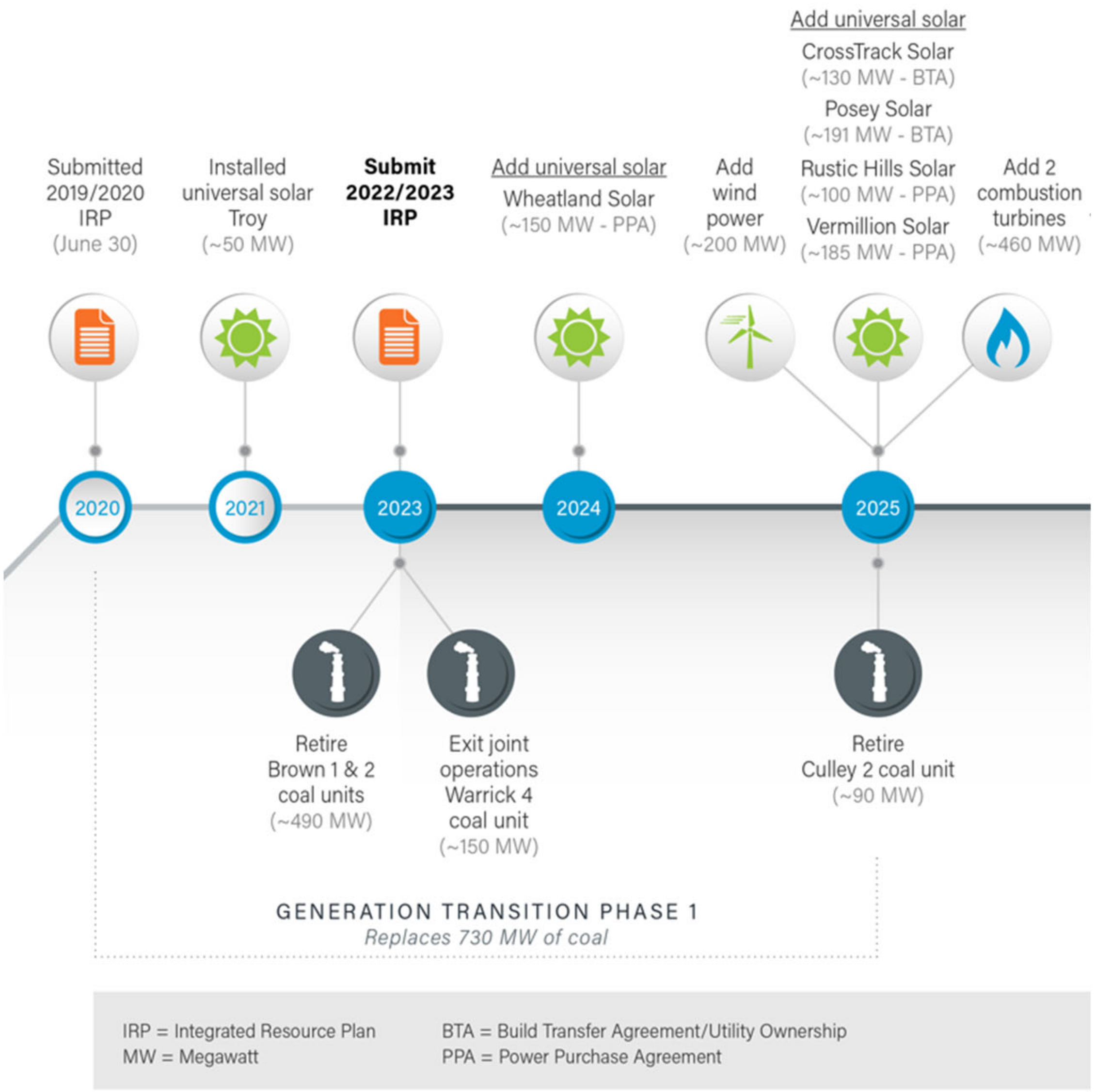


200 families of inputs where each iteration (family) reflects variable levels and paths that are tied together by correlations

Risk Analysis Methodology

- Utilize 200 draws from Scenario inputs for Gas, Coal, Load
- Renewable + storage capital cost variation in risk analysis
  - Assigned to 200 EnCompass draws based on:
    - First 50 draws - Low forecast
    - Next 100 draws - Reference case forecast
    - Last 50 draws - High forecast
  - Every 4 years, draws randomly “reshuffled” and above assignments are made
- CO_2 forecast variation in risk analysis - Assigned to 200 EnCompass draws based on:
    - First 120 draws use Reference case forecast ($0/Ton)
    - Next 40 draws use Medium forecast
    - Last 40 draws use High forecast

IRP Portfolio Decisions



- FB Culley 2 & 3 conversion or retirement decision is a key part of this IRP
- With MISO's shift to seasonal construct there is a capacity shortfall in 2024 prior to the CTs coming online and then into the 2030s
- Analyzed a wide range of portfolios that provide insights around the F.B. Culley decision and the future resource mix

Range of IRP Portfolios

CenterPoint Energy

Portfolio Strategy Group	Portfolio
Reference	Optimized Portfolio in Reference Case conditions
Scenario-Based	Optimized Portfolio using High Regulatory scenario assumptions
	Optimized Portfolio using Market Driven Innovation scenario assumptions
	Optimized Portfolio using Decarbonization/Electrification scenario assumptions
	Optimized Portfolio using High Inflation and Supply Chain Issues scenario assumptions
Deterministic	Business as Usual (Continue to run FB Culley 3 through 2042)
	AB Brown CTs with and without CCGT conversion
	FB Culley 2 or 3 gas conversion
	FB Culley 2 and 3 gas conversion
	Retire FB Culley 2 by 2025 • Replace with non-thermal (Wind, Solar, Storage) • Replace with thermal (CCGT, CT)
	Retire FB Culley 3 by 2029 • Replace with non-thermal (Wind, Solar, Storage) • Replace with thermal (CCGT, CT)
	Retire FB Culley 3 by 2035 • Replace with non-thermal (Wind, Solar, Storage) • Replace with thermal (CCGT, CT)

Range of Portfolios

- Starting from the 12 portfolios that were presented at the third stakeholder meeting, additional portfolios and iterations of portfolios were developed based on:
  - Continue right sizing portfolios on both for capacity and energy
  - To examine tradeoffs in different existing resource decision timing
  - Stakeholder feedback
  - Lessons learned from preliminary portfolio optimization results

Portfolio Screening

- After iterative portfolio development and testing, portfolios were screened in order to maintain a reasonable number of portfolios to run through risk analysis
- Portfolios were screened primarily based on the following
  - Portfolio similarities and overlap
    - Desire portfolios that are included in risk analysis to be different enough to provide insights between different options (not have 10 portfolios that include the same resource types)
  - Right sizing for CNP and customers
    - Meets seasonal capacity requirements, while not significantly over built
    - Does not over rely on the market for energy sales or energy purchases
  - Cost

Portfolio Screening For Risk Analysis -
12.13.22 Stakeholder Meeting Draft Optimized Portfolios

CenterPoint Energy

Year	Reference Case	Market Driven Innovation	Decarbonization/ Electrification
2024	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)	Solar (635MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)	Retire FB Culley 2 Solar (130MW) CTs (460MW)
2026			
2027	CCGT Conversion	CCGT Conversion	CCGT Conversion
2028			
2029	Retire FB Culley 3	Retire FB Culley 3 Storage (1 x 10MW)	Retire FB Culley 3
2030			Wind North (1 x 200MW)
2031			
2032			Long Duration Storage (300MW) Wind North (1 x 200MW)
2033	Wind North (3 x 200MW)		Wind North (3 x 200MW)
2036			
2041		Storage (1 x 10MW)	
2042		Storage (2 x 10MW)	

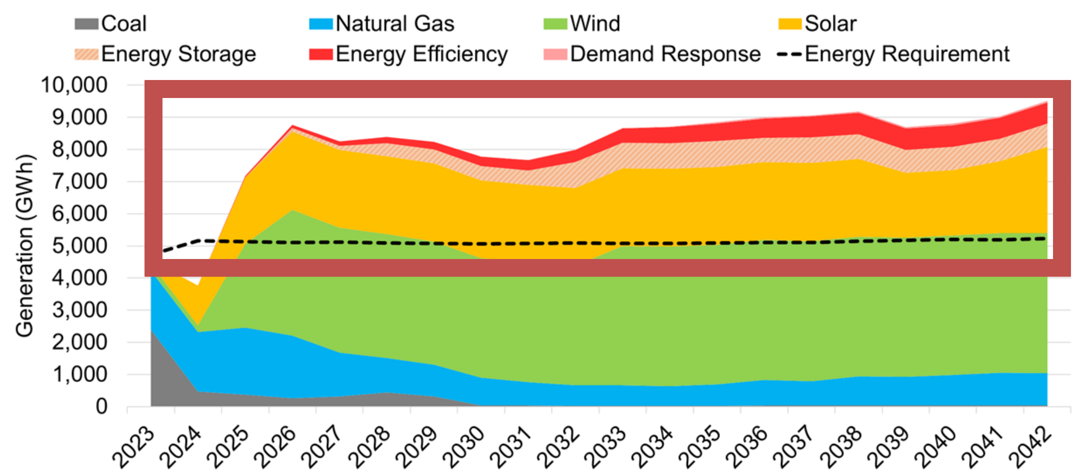
Common themes across several portfolios:

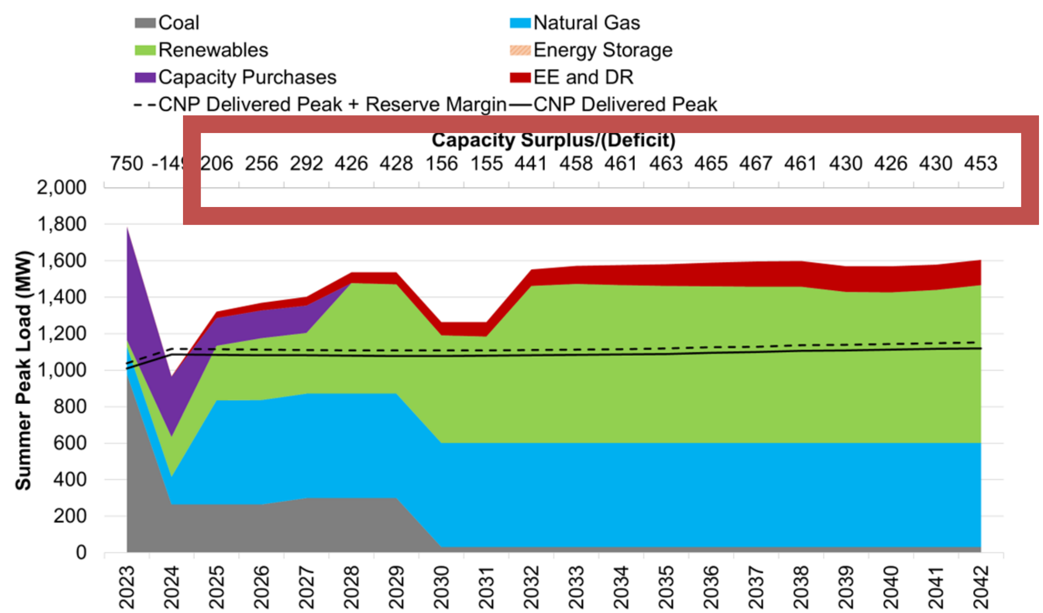
- AB Brown CT to CCGT Conversion
- Retire Culley 3 in 2029
- New wind resources being added

Portfolio Screening - Right sizing CenterPoint and Customer needs

- Several portfolios which were hundreds of MW long on capacity and/or over generated energy compared to CNP need throughout study period were screened out
- Resource mixes and portfolio concepts learned were included in deterministic portfolios at smaller scale

Energy Generation Mix





Portfolio Screening - Cost

Year	Diversified Renewables	Diversified Renewables (With Hydro)
2023	Exit Warrick 4	Exit Warrick 4
2024	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)
2026		
2027		
2028		
2029	Retire FB Culley 3 Wind (200MW)	Retire FB Culley 3
2030	Storage (200MW) Solar (200MW) Wind (200MW)	Storage (200MW) Hydro (58MW)
2031		
2032		Wind (200MW)
2033	Wind (200MW)	Wind (600MW)
2041		
2042		

- Portfolios which were significantly higher on cost when run through the reference case were screened prior to the risk analysis
- Portfolios which tested adding/replacing a specific resource(s) that decreased portfolio performance were also screened

Balanced Portfolio Buildouts (1 of 2)

CenterPoint Energy

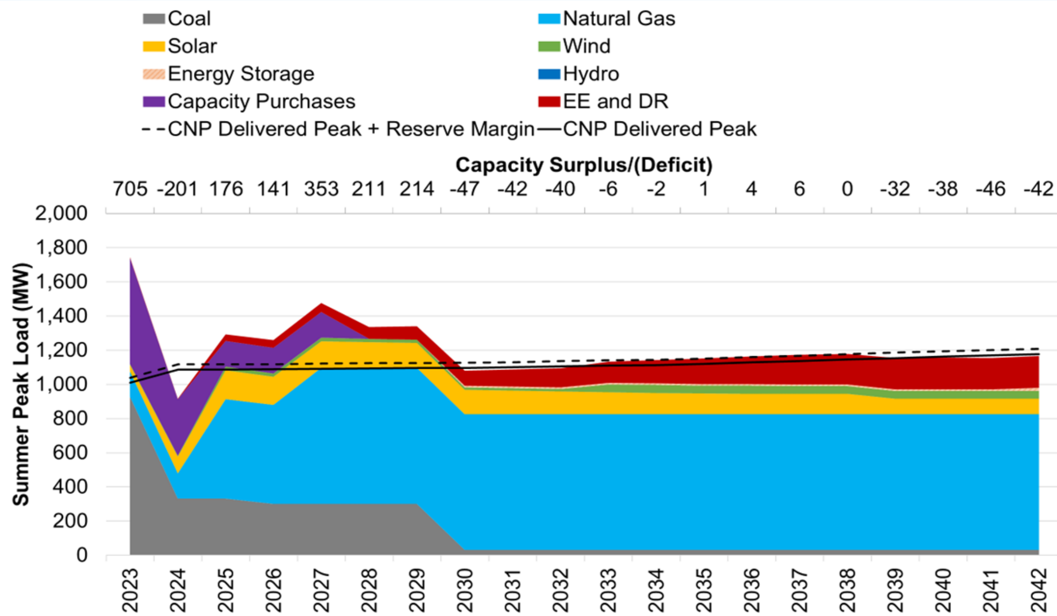
Year	Reference Case	Business as Usual (BAU) Cont. FB Culley 3 on Coal	Convert F.B. Culley 3 to Natural Gas by 2030	Convert F.B. Culley 3 to Natural Gas by 2027	Convert F.B. Culley 3 to Natural Gas by 2027 with Wind and Solar
2023	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4
2024	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Continue FB Culley 3 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)
2026					
2027	CCGT Conversion			Covert FB Culley 3 to Natural Gas	Covert FB Culley 3 to Natural Gas Wind (200MW) Solar (200MW)
2028					
2029	Retire FB Culley 3	Storage (10 MW)			
2030		Wind (200MW)	Covert FB Culley 3 to Natural Gas Wind (200MW) Solar (200MW)	Wind (200MW) Solar (200MW)	
2031					
2032			Wind (200MW)	Wind (200MW)	Wind (200MW)
2033	Wind (400MW)		Wind (200MW)	Wind (200MW)	Wind (200MW)
2041	Storage (10MW)				
2042		Storage (10 MW)			

Balanced Portfolio Buildouts (2 of 2)

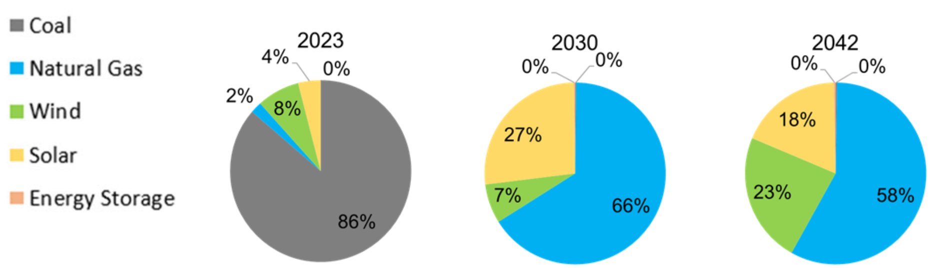
Year	CT Portfolio (Replace FB Culley 3 with F Class CT)	Diversified Renewables	Diversified Renewables (Early Storage & DG Solar)	Replace FB Culley 3 with Storage and Wind	Replace FB Culley 3 with Storage and Solar
2023	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4	Exit Warrick 4
2024	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)	Solar (341MW) Wind (200MW)
2025	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)	Retire FB Culley 2 Solar (415MW) CTs (460MW)
2026					
2027			Solar (60MW)		
2028			Storage (90MW)		
2029	Retire FB Culley 3	Retire FB Culley 3 Wind (200MW)	Retire FB Culley 3	Retire FB Culley 3	Retire FB Culley 3
2030	F-Class CT Storage (60MW)	Storage (200MW) Solar (200MW) Wind (200MW)	Storage (100MW) Wind (400MW) Solar (100MW)	Storage (300MW) Wind (400MW)	Storage (250MW)
2031					
2032					
2033	Wind (600 MW)	Wind (200MW)	Wind (200MW)	Wind (200MW)	Solar (300MW)
2041			Solar (100MW)		
2042			Solar (100MW)		Storage (10MW)

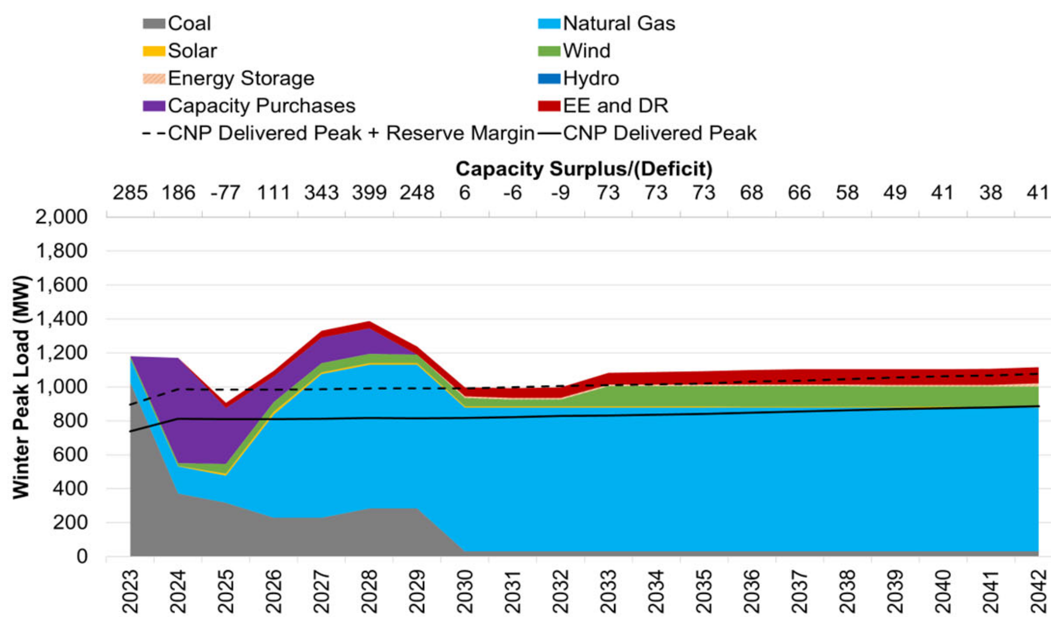
Reference Case (Unconstrained)

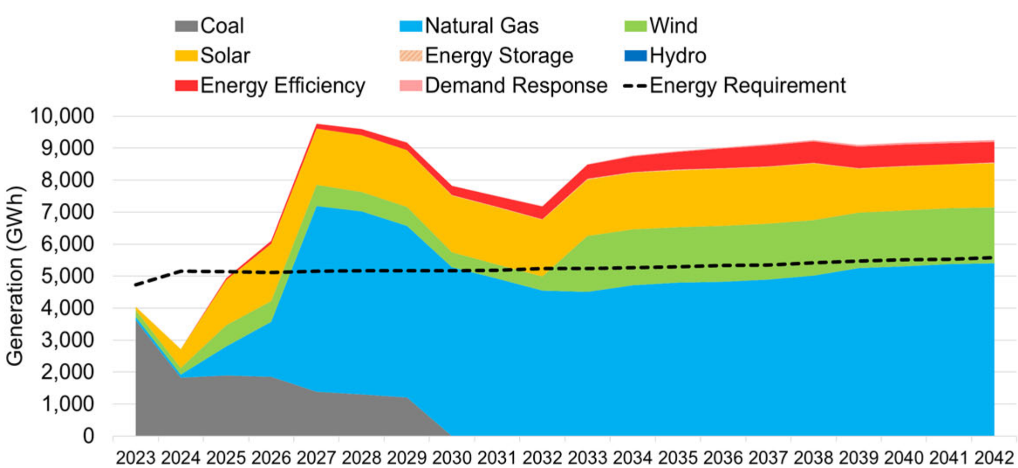
- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Conversion of CTs to CCGT
- Wind in 2033 and Storage in 2041



Stochastic Generation

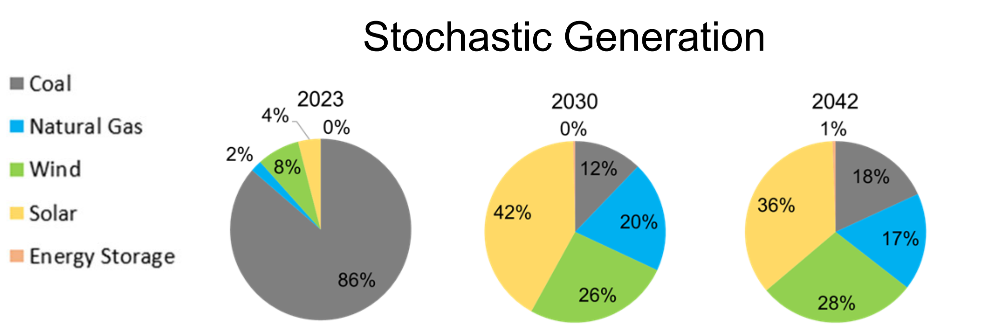


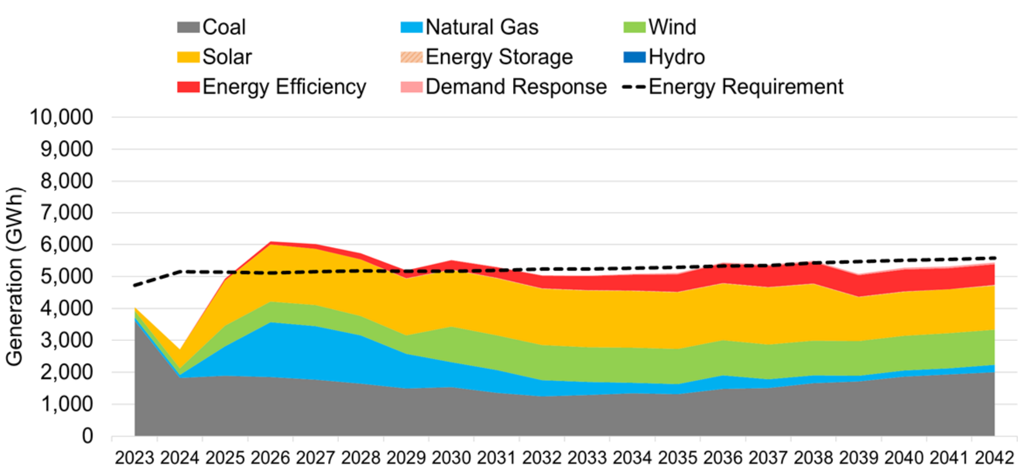


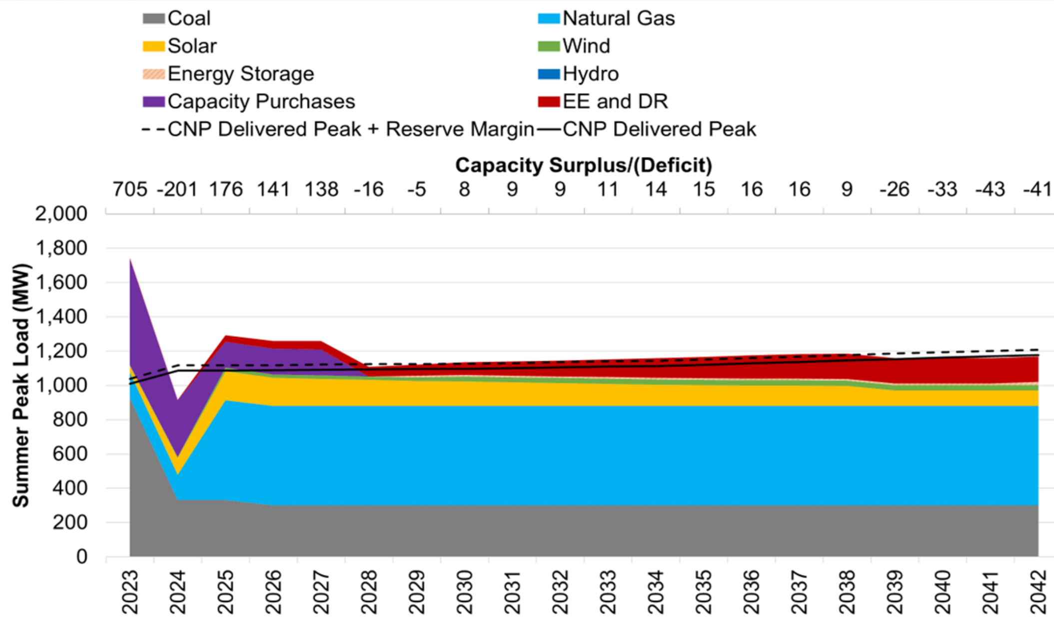


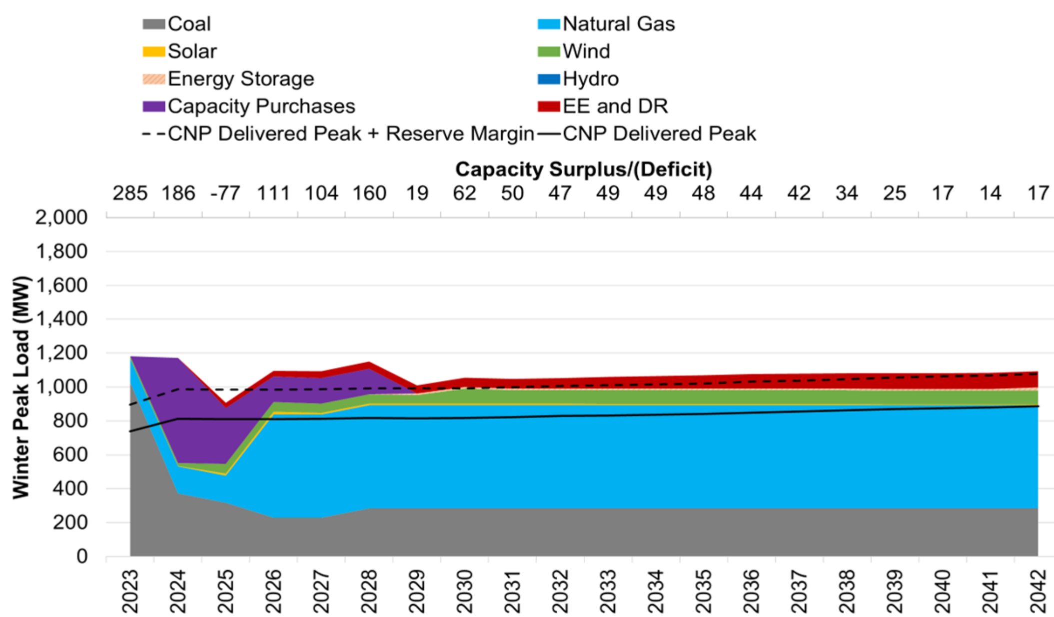
Business as Usual (BAU) Cont. FB Culley 3 on Coal

- 2025 retirement of FB Culley 2
- Continue FB Culley 3 on coal
- Wind in 2030
- 10 MW Storage in 2029 and 2042





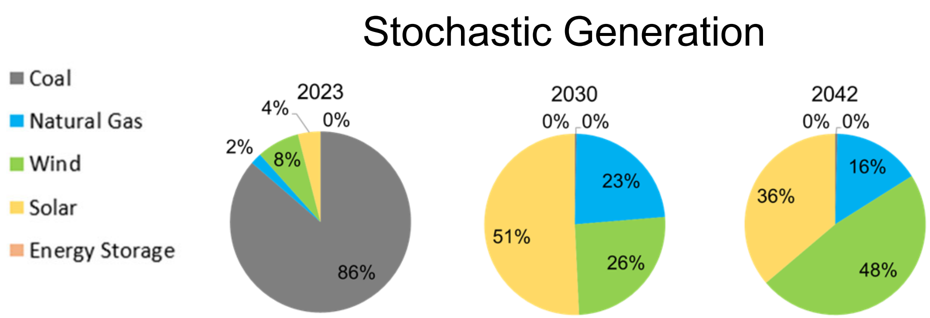


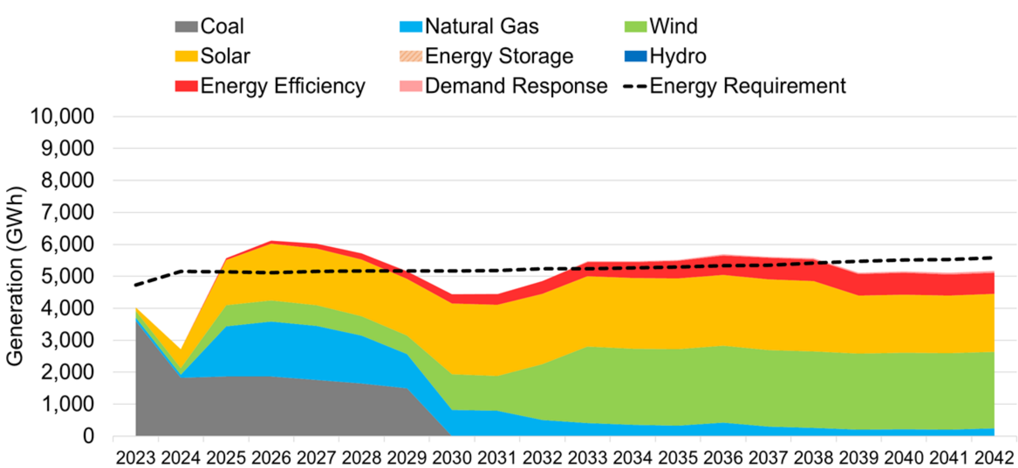


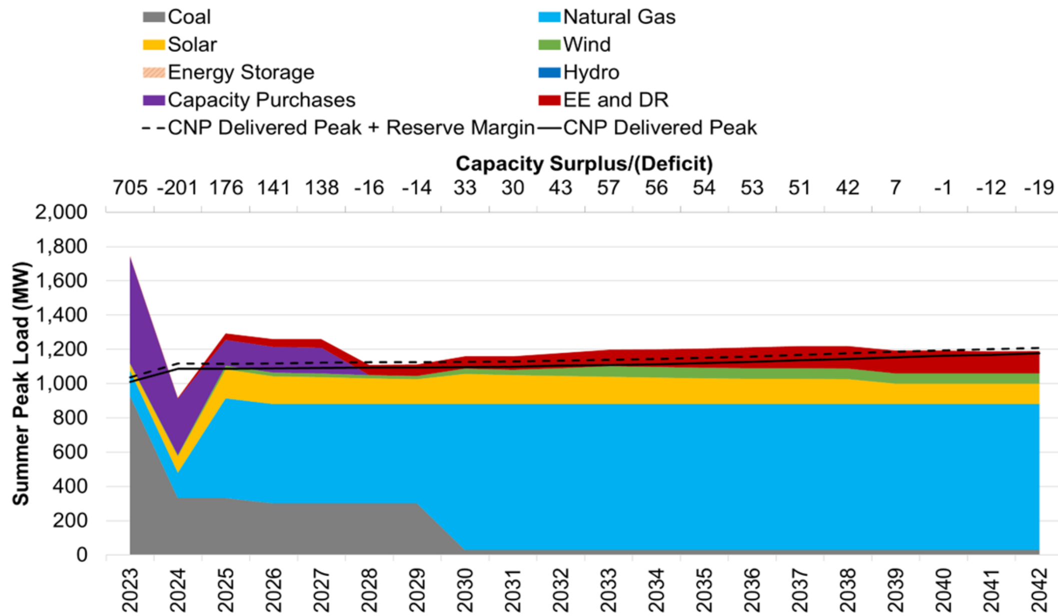
Convert F.B. Culley 3 to Natural Gas by 2030

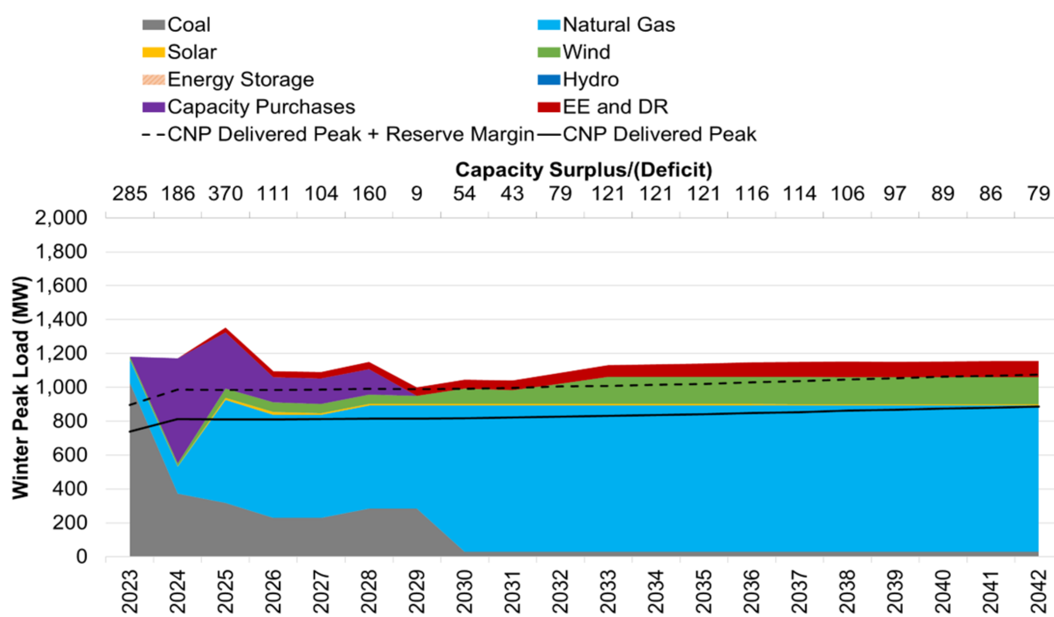
CenterPoint Energy

- 2025 retirement of FB Culley 2
- 2030 conversion of FB Culley 3 to NG
- Wind in early 2030s
- Solar in 2030



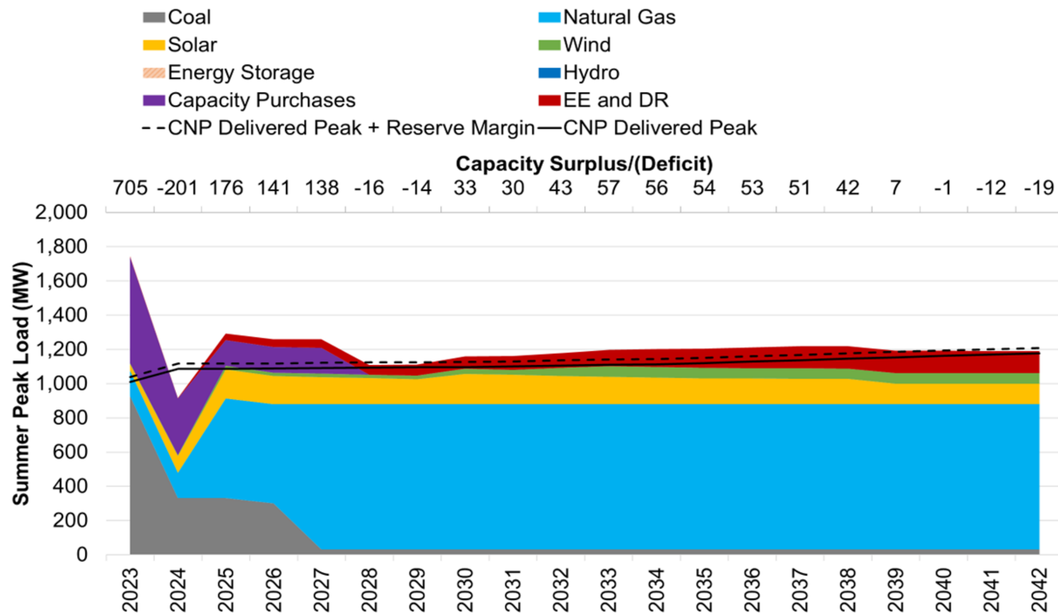


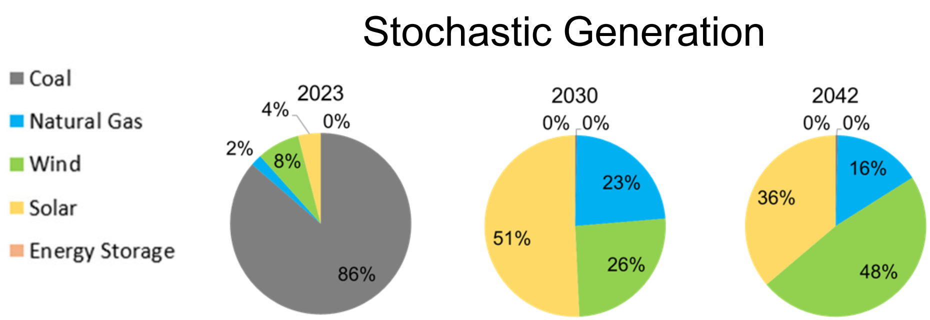


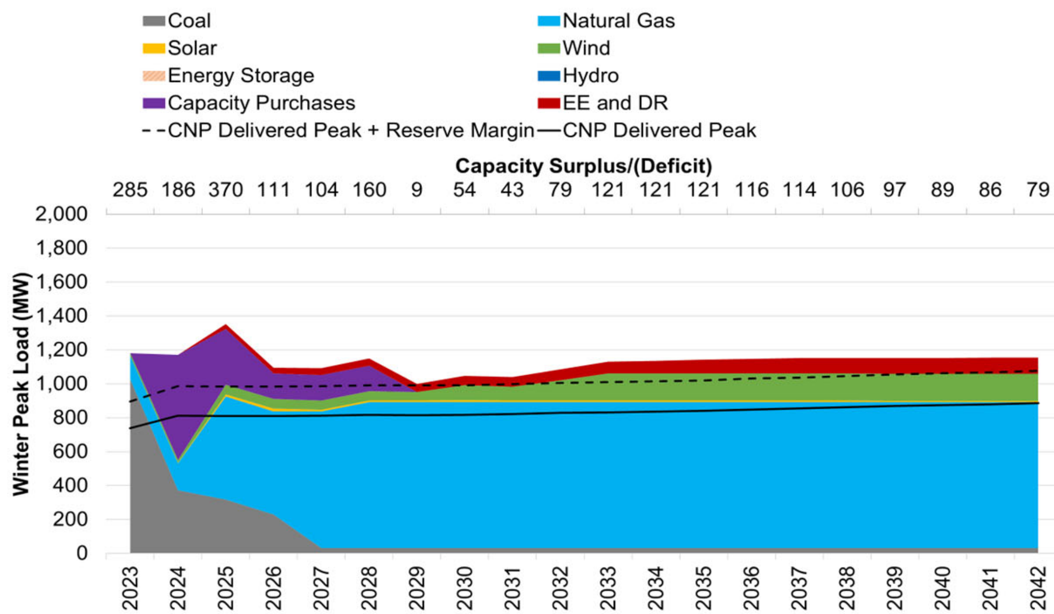


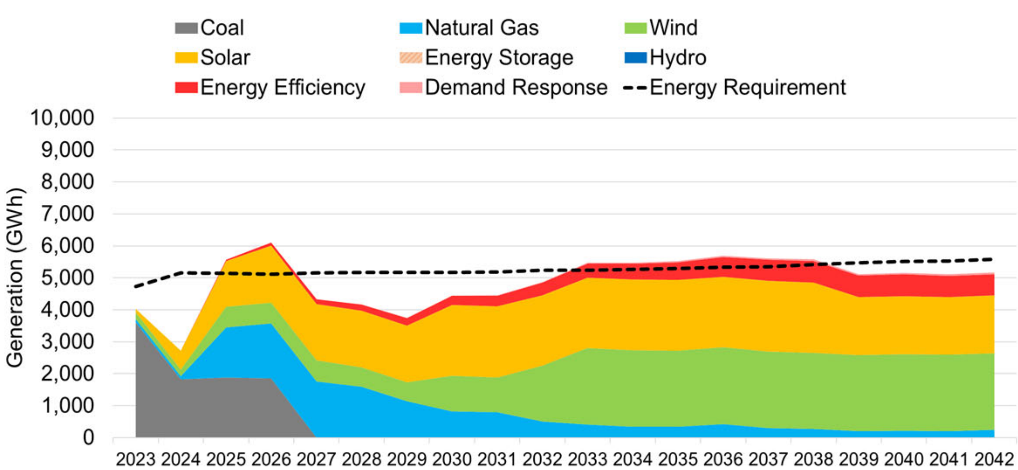
Convert F.B. Culley 3 to Natural Gas by 2027

- 2025 retirement of FB Culley 2
- 2027 conversion of FB Culley 3 to NG
- Wind in early 2030s
- Solar in 2030



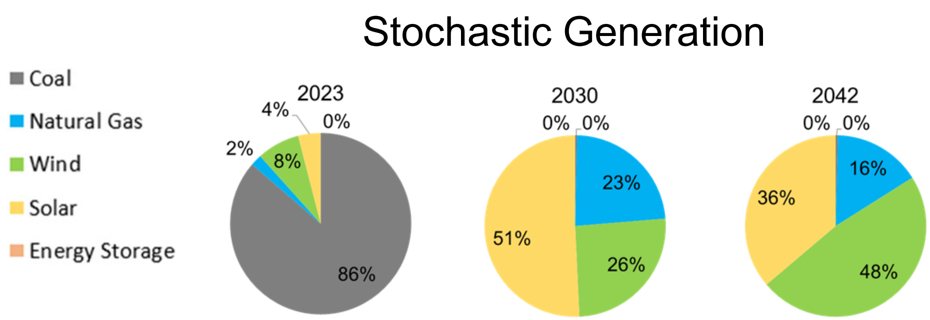


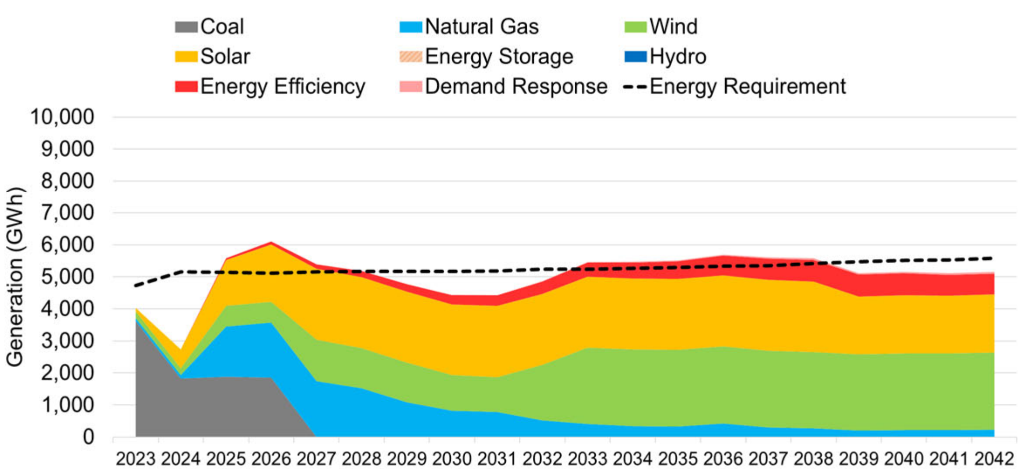


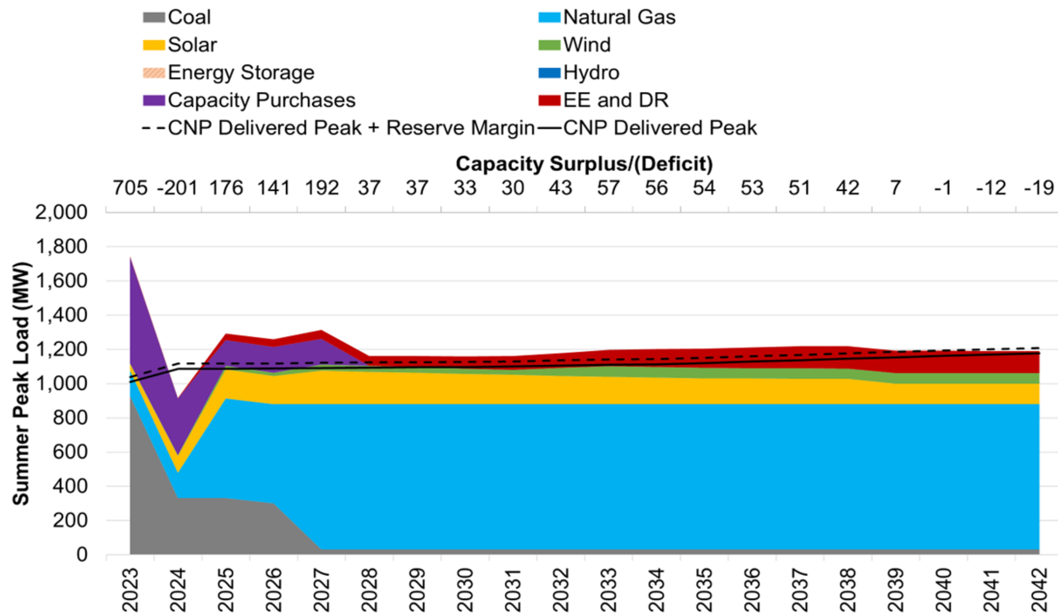


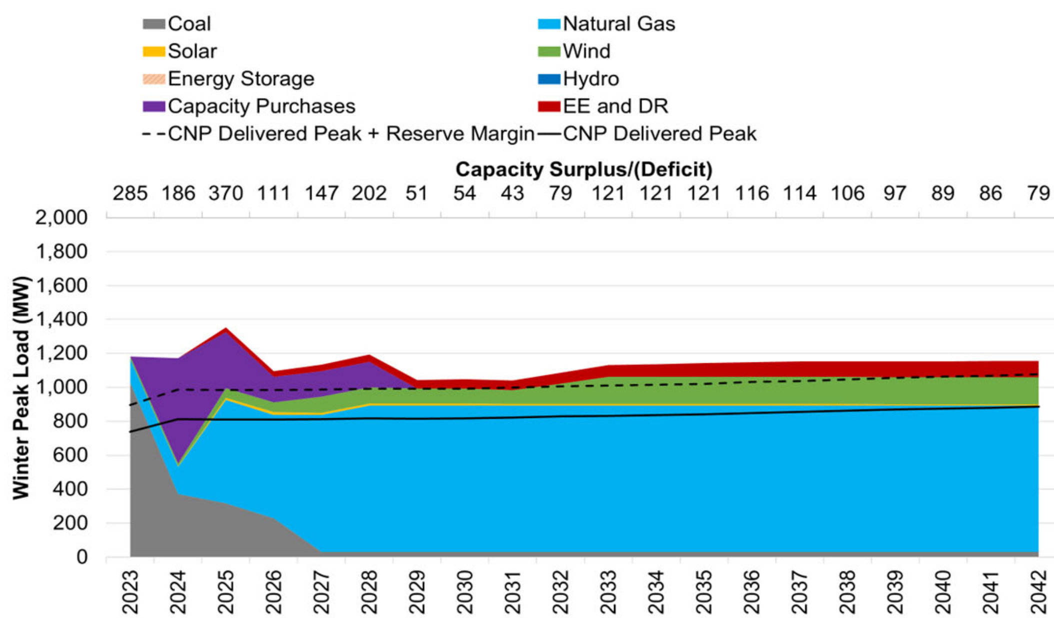
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 Wind and Solar

- 2025 retirement of FB Culley 2
- 2027 conversion of FB Culley 3 to NG
- Wind and solar in 2027
- Additional wind in early 2030s



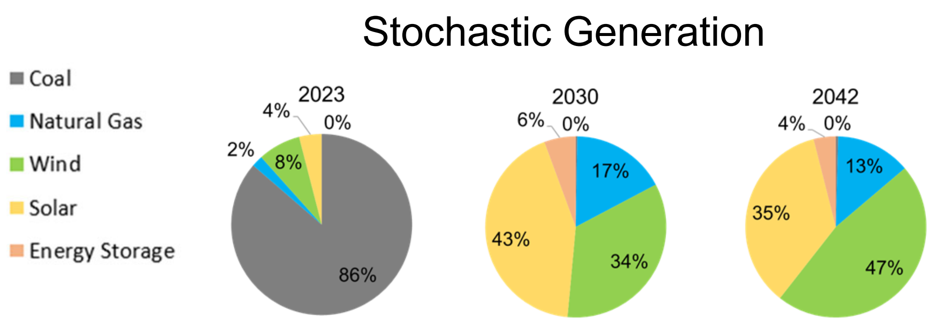


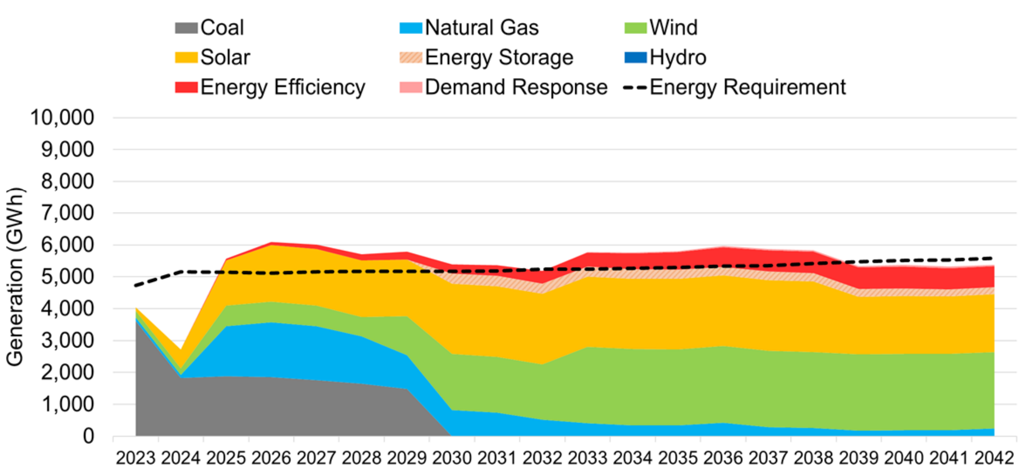


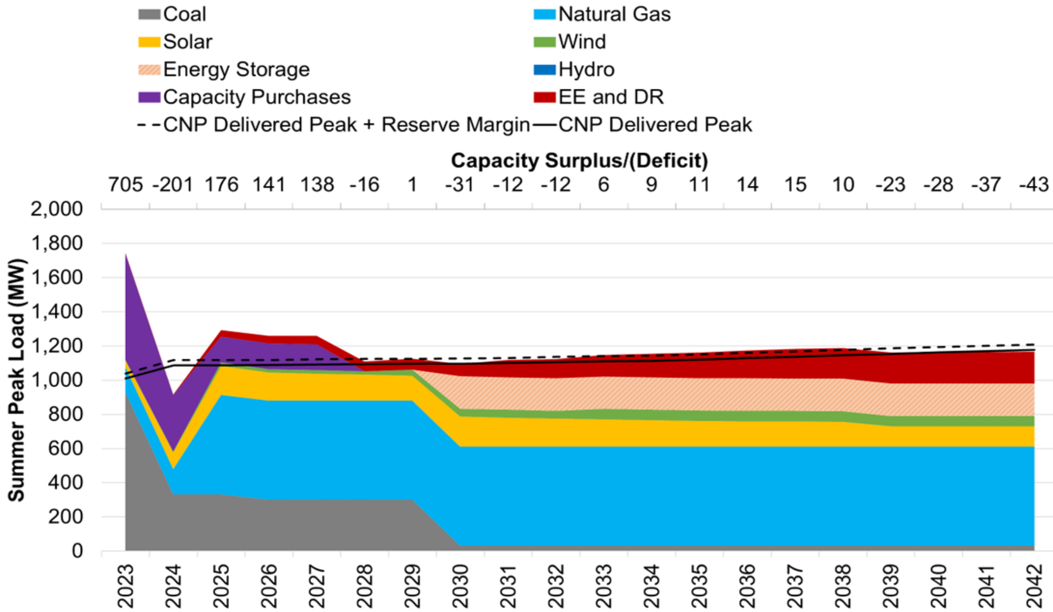


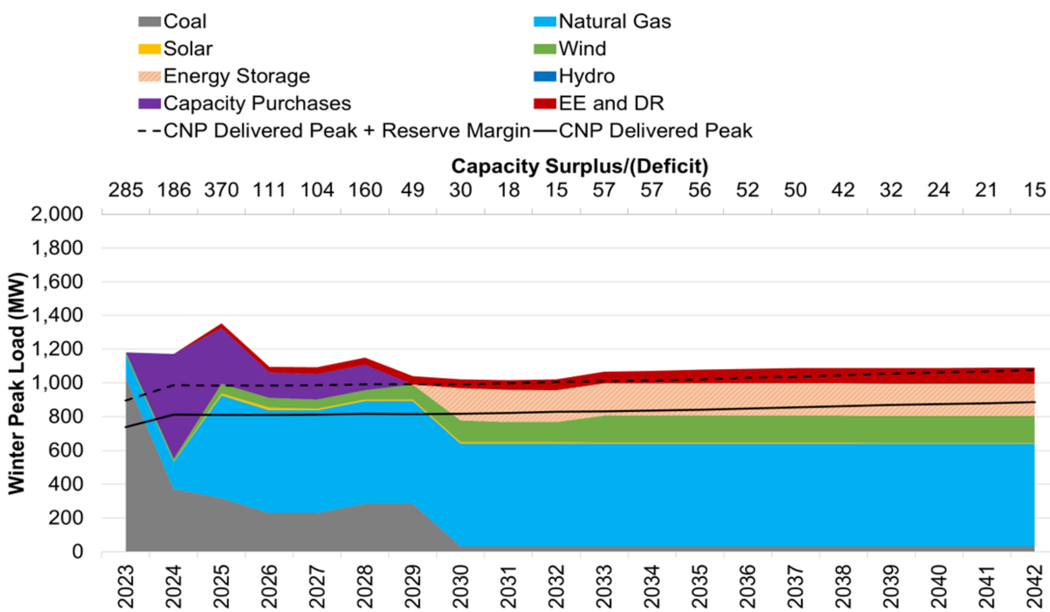
Diversified Renewables

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Wind in 2029 and 2030s
- Solar and Storage in 2030





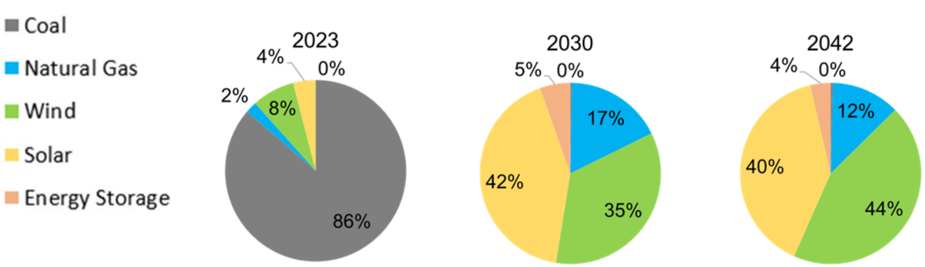


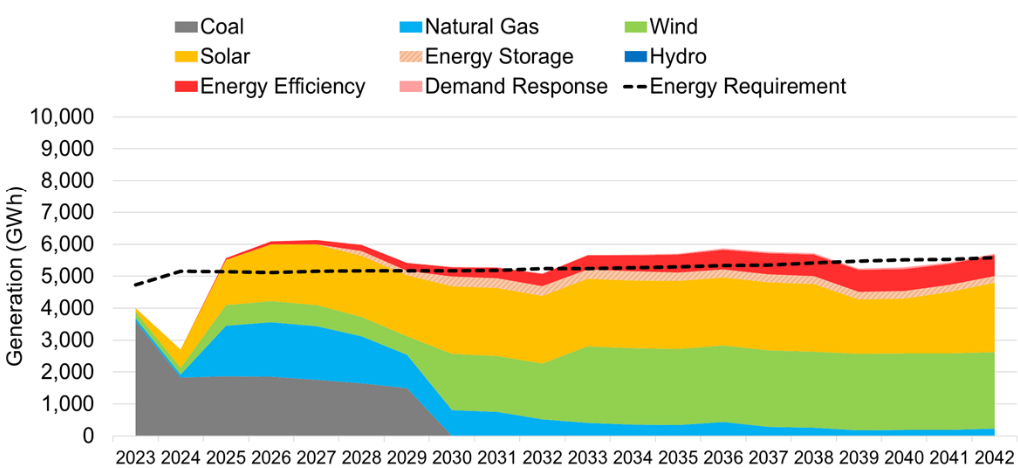


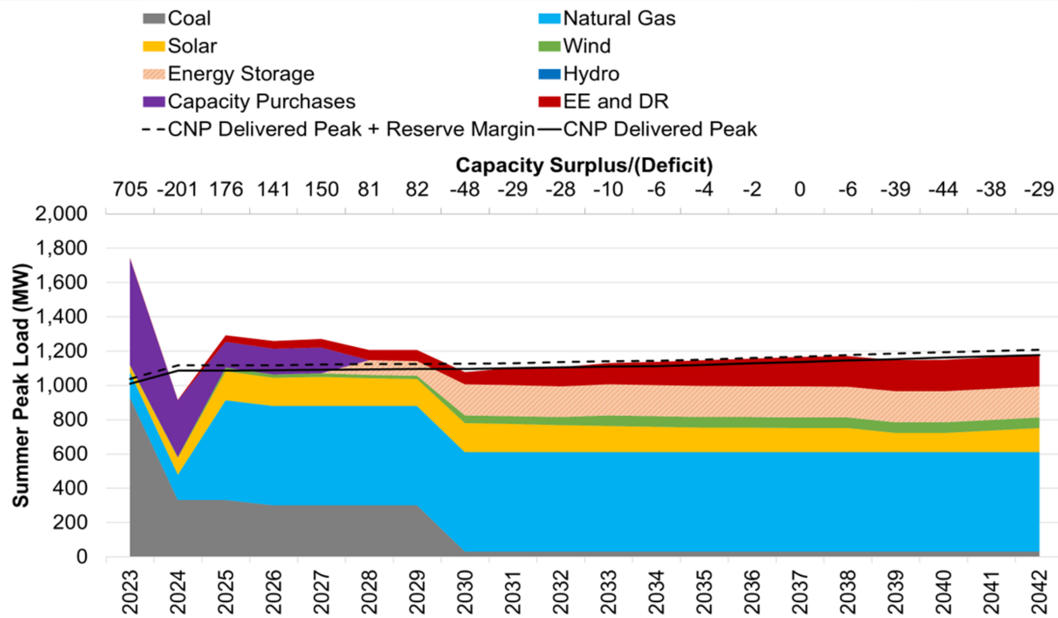
Diversified Renewables (Early Storage & DG Solar)

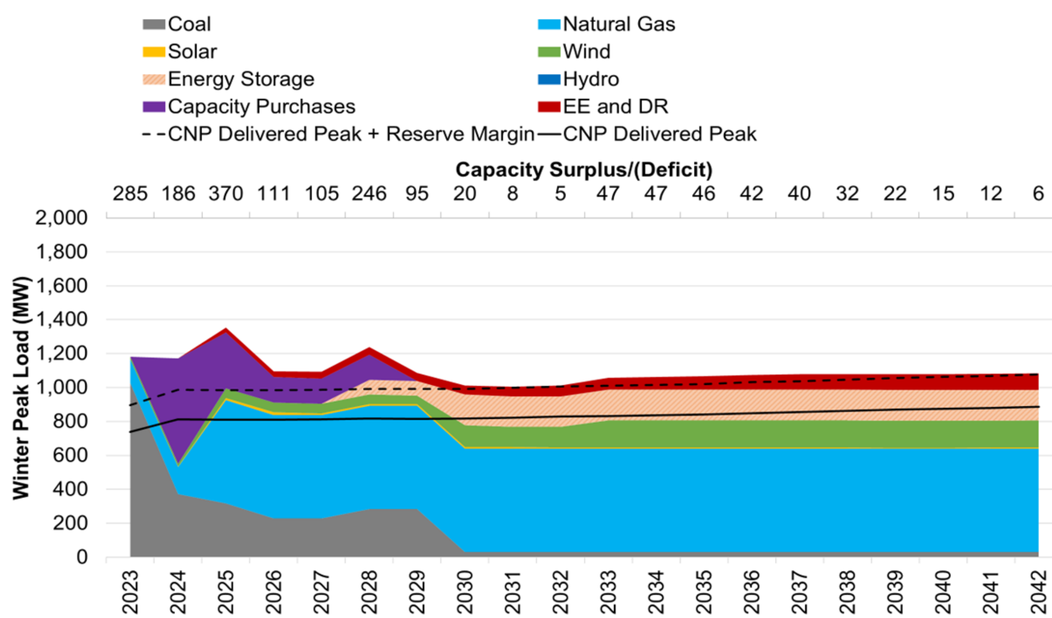
- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- DG Solar + Solar through study period
- Storage in 2028 and 2030
- Wind in 2030s

Stochastic Generation





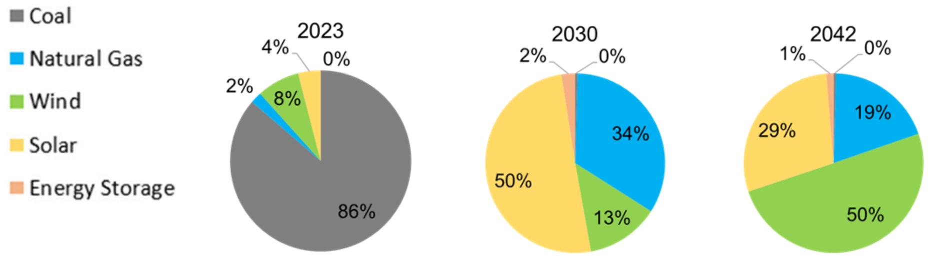


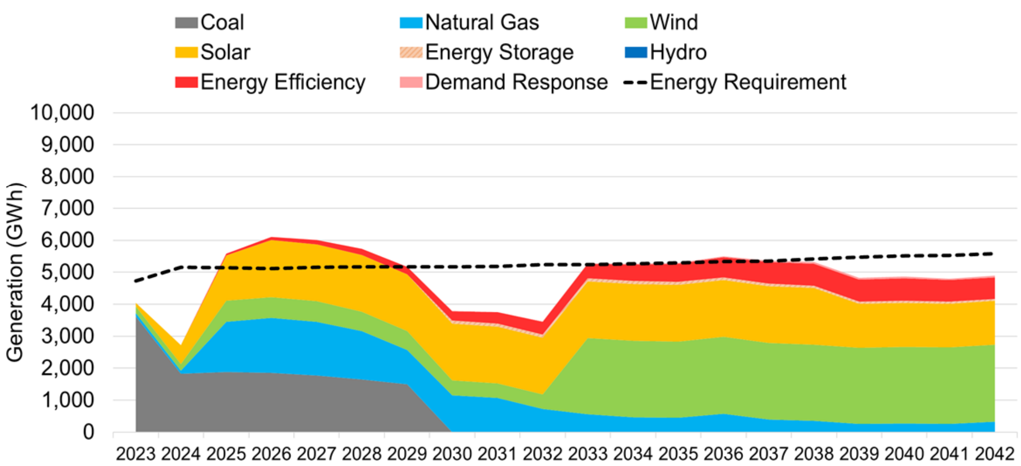


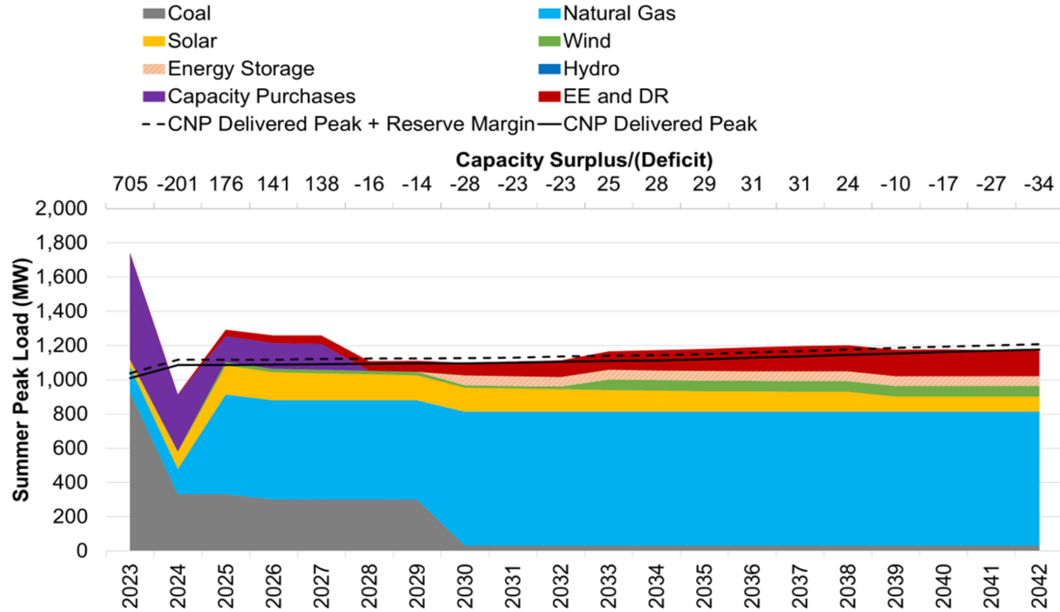
CT Portfolio (Replace FB Culley 3 with F Class CT)

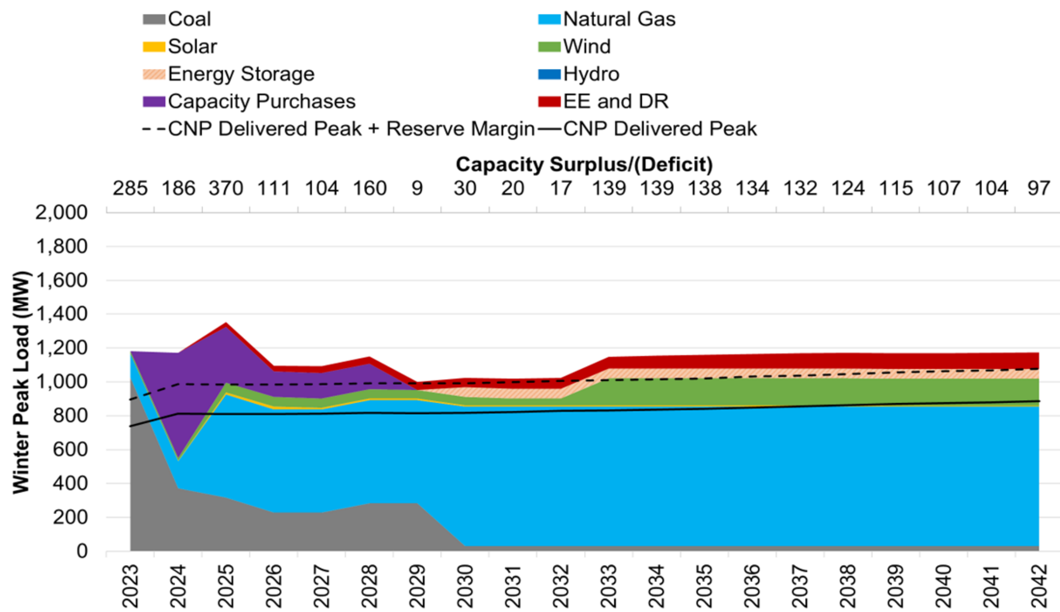
- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- F-Class CT in 2030
- Storage in 2030
- Wind in 2033

Stochastic Generation



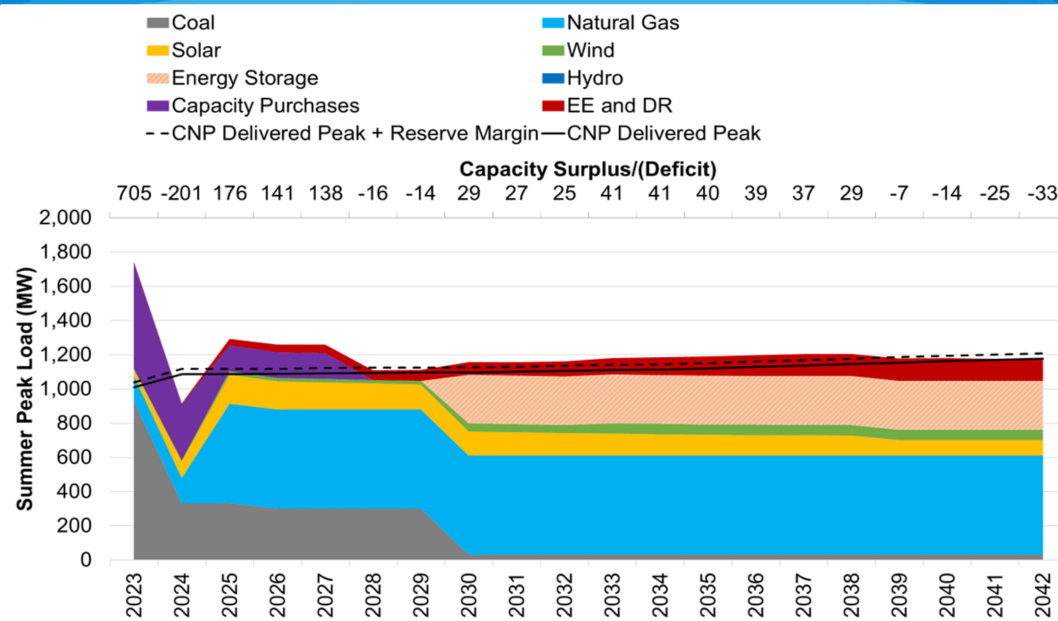




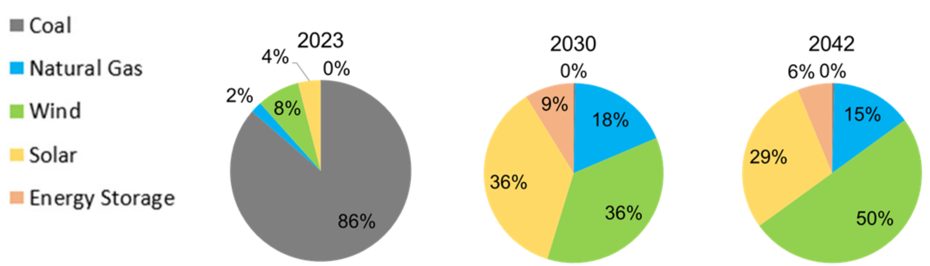


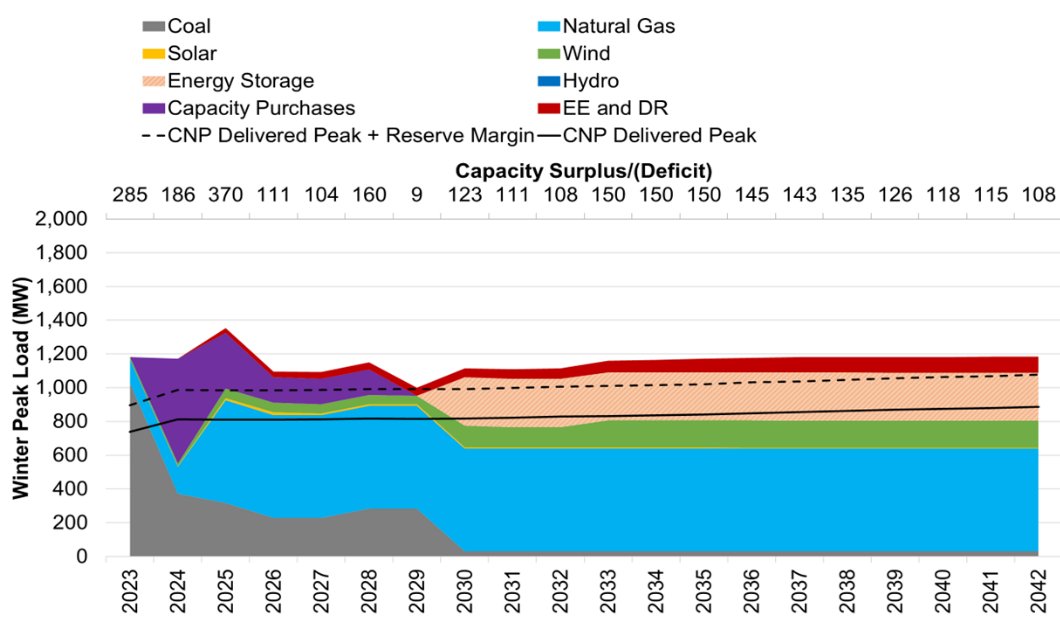
Replace FB Culley 3 with Storage and Wind

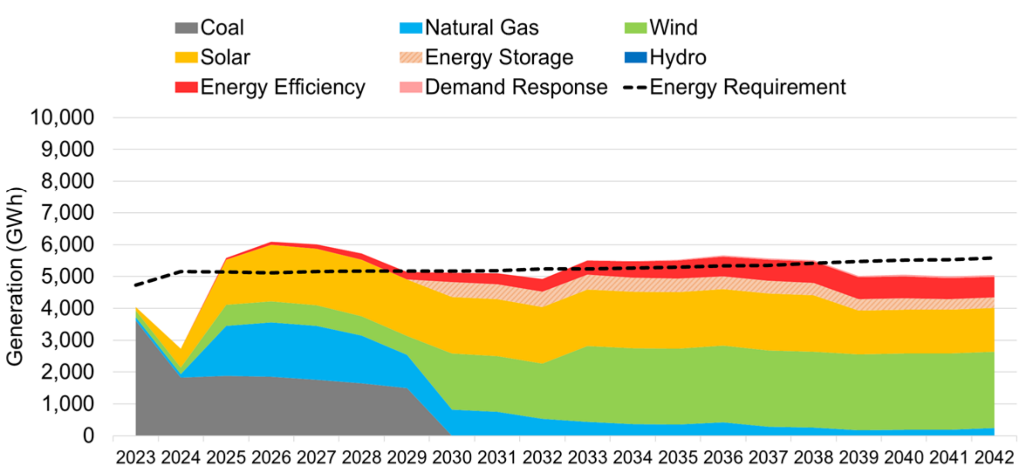
- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Wind in 2030s
- Storage in 2030



Stochastic Generation

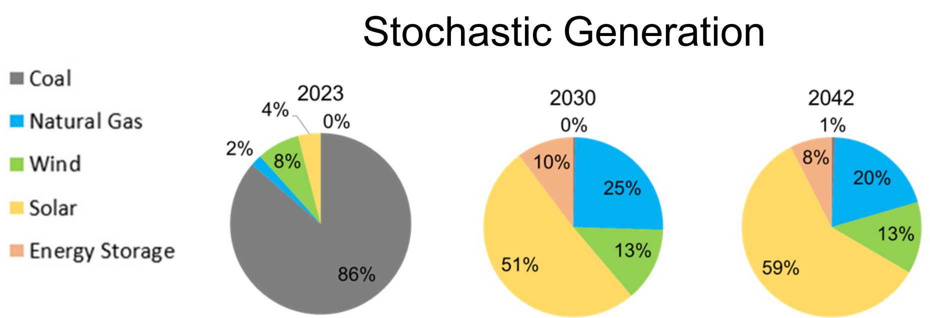


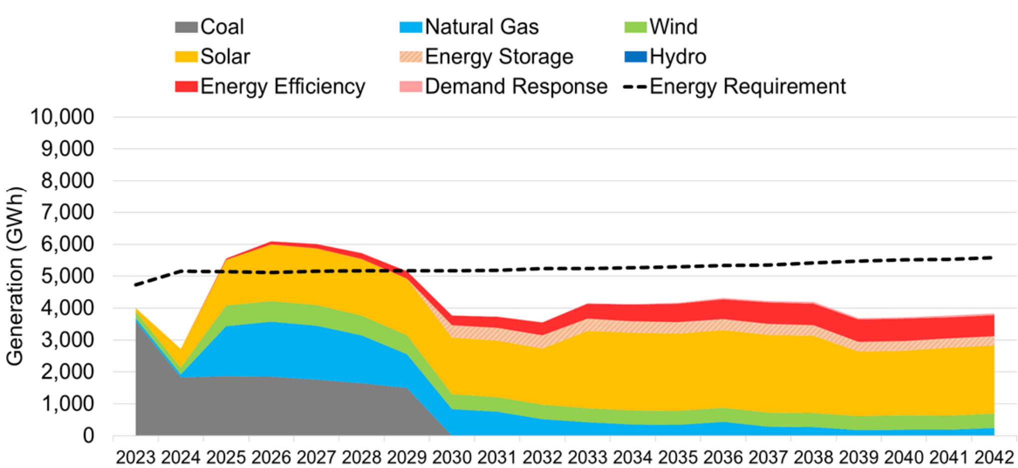


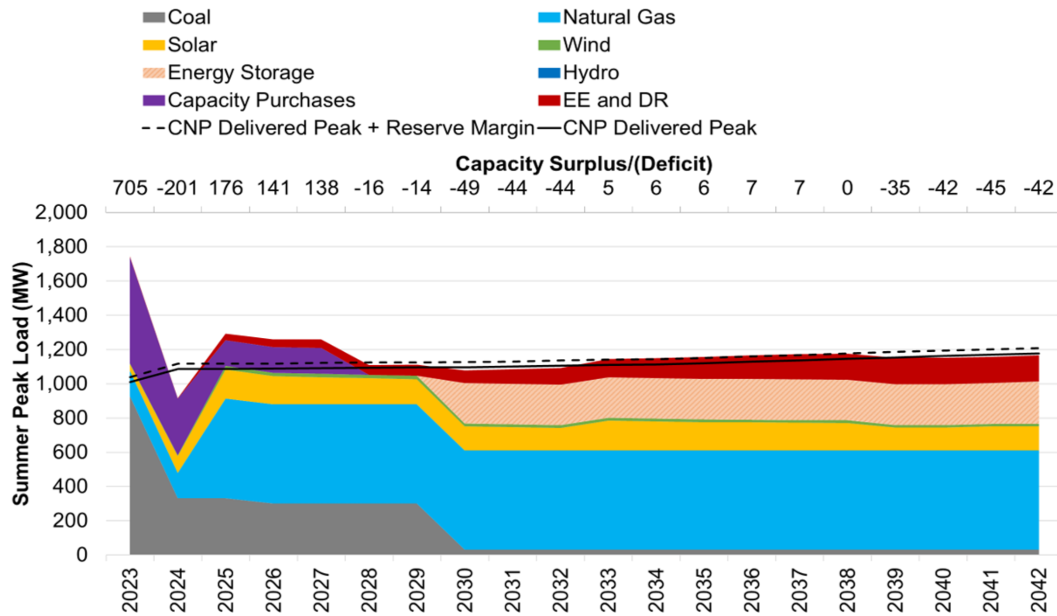


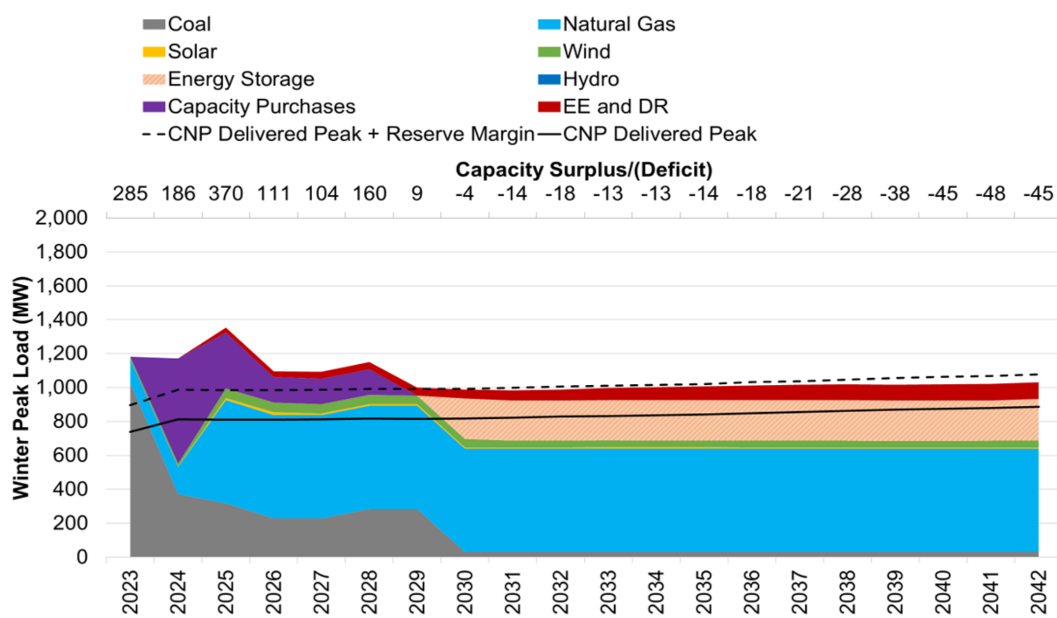
Replace FB Culley 3 with Storage and Solar

- 2025 retirement of FB Culley 2
- 2029 retirement of FB Culley 3
- Storage in 2030
- Solar in 2033









Q&A

Risk Analysis Scorecard

Matt Lind, 1898

Balanced Scorecard Affordability/Cost Risk

Portfolio	20 Year NPVRR ($M)	Delta From Reference (%)	Proportion of Energy Generated by Resources With Exposure to Coal and Gas Markets and Market Purchases (%)[1]	95% Value of NPVRR ($)
Reference Case	$4,214	0.0%	56%	$4,952
F-Class CT	$4,499	6.7%	30%	$5,413
Convert F.B. Culley 3 to Natural Gas by 2027	$4,503	6.8%	27%	$5,316
Convert F.B. Culley 3 to Natural Gas by 2030	$4,508	7.0%	27%	$5,332
Replace FB Culley 3 with Storage and Solar	$4,539	7.7%	29%	$5,416
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	$4,559	8.2%	25%	$5,347
Replace FB Culley 3 with Storage and Wind	$4,580	8.7%	26%	$5,328
Business as Usual	$4,581	8.7%	35%	$5,486
Diversified Renewables	$4,583	8.8%	25%	$5,313
Diversified Renewables (Early Storage & DG Solar)	$4,676	11.0%	25%	$5,408

1: Total energy generation from coal and gas / total fleet generation from 2023 - 2042

Balanced Scorecard
Environmental Sustainability

CenterPoint Energy

Portfolio	CO2 Intensity (Tons CO_2/kwh)[2]	CO2 Equivalent Emissions (Stack Emissions Tons CO_2e)[3]
Reference Case	0.00024	33,199,947
F-Class CT	0.00018	17,975,167
Convert F.B. Culley 3 to Natural Gas by 2027	0.00015	15,506,174
Convert F.B. Culley 3 to Natural Gas by 2030	0.00016	16,953,911
Replace FB Culley 3 with Storage and Solar	0.00018	15,917,099
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	0.00014	15,382,405
Replace FB Culley 3 with Storage and Wind	0.00015	15,931,427
Business as Usual	0.00025	23,897,336
Diversified Renewables	0.00015	15,763,426
Diversified Renewables (Early Storage & DG Solar)	0.00015	15,766,880

2: Average CO_2e from generation / average fleet generation from 2030 - 2042

**CO_2e shown in metric tons*

3: Sum of CO_2e emissions from 2023 - 2042

Balanced Scorecard Reliability

CenterPoint Energy

Portfolio	Must Meet MISO Planning Reserve Margin Requirement in All Seasons (MW)[4]		Fast Start Capability (MW)[5]	Dispatchable Resource with Spinning Reserve Capability (MW)[6]
	Summer	Winter		
Reference Case	97	62	11	919
F-Class CT	80	22	758	900
Convert F.B. Culley 3 to Natural Gas by 2027	60	21	469	941
Convert F.B. Culley 3 to Natural Gas by 2030	60	21	469	941
Replace FB Culley 3 with Storage and Solar	101	137	720	671
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	60	21	469	941
Replace FB Culley 3 with Storage and Wind	74	9	769	671
Business as Usual	90	74	480	941
Diversified Renewables	89	71	669	671
Diversified Renewables (Early Storage & DG Solar)	94	81	659	671

4: Maximum seasonal capacity deficit in summer/winter from 2030 - 2042

5: Average MW of installed battery, CT, recip capacity from 2030 - 2042

6: Average MW of dispatchable resources from 2030 - 2042

Balanced Scorecard
Market Risk Minimization

Portfolio	Energy Market Purchases[7]			Energy Market Sales[7]			Capacity Market Purchases/Sales (%)[8]	
	Average	Near Term Max	Long Term Max	Average	Near Term Max	Long Term Max	Purchases	Sales
Reference Case	12%	24%	18%	33%	42%	41%	1.2%	12%
F-Class CT	28%	40%	46%	17%	21%	24%	0.8%	11%
Convert F.B. Culley 3 to Natural Gas by 2027	26%	39%	32%	19%	22%	27%	0.6%	12%
Convert F.B. Culley 3 to Natural Gas by 2030	25%	35%	32%	19%	22%	27%	0.6%	12%
Replace FB Culley 3 with Storage and Solar	38%	43%	49%	13%	21%	17%	1.7%	8%
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	24%	31%	32%	20%	24%	27%	0.6%	13%
Replace FB Culley 3 with Storage and Wind	27%	35%	33%	15%	21%	21%	0.7%	12%
Business as Usual	31%	35%	36%	14%	21%	19%	0.9%	10%
Diversified Renewables	25%	31%	30%	18%	22%	24%	1.1%	9%
Diversified Renewables (Early Storage & DG Solar)	25%	34%	30%	18%	22%	24%	1.2%	9%

7: Average GWh energy market interaction / total energy + sales from 2023 - 2042

Near Term: 2026 - 2030

Long Term: 2031 - 2042

8: Average capacity market purchases / coincident peak demand from 2023 - 2042

Balanced Scorecard Results

CenterPoint Energy

Scorecard - Ranked	Affordability / Cost Risk				Environmental Sustainability		Reliability				Market Risk Minimization							
Portfolio	20 Year NPVRR ($M)	Delta From Reference (%)	Proportion of Energy Generated by Resources With Exposure to Coal and Gas Markets and Market Purchases (%)[1]	95% Value of NPVRR ($)	CO2 Intensity (Tons CO_2/kwh)[2]	CO2 Equivalent Emissions (Stack Emissions) (Tons CO_2)[3]	Must Meet MISO Planning Reserve Margin Requirement in All Seasons (MW)[4]		Fast Start Capability (MW)[5]	Dispatchable Resource with Spinning Reserve Capability (MW)[6]	Energy Market Purchases[7]			Energy Market Sales[7]			Capacity Market Purchases or Sales (%)[8]	
							Summer	Winter			Average	Near Term Max	Long Term Max	Average	Near Term Max	Long Term Max	Purchases	Sales
Reference Case	$4,214	0.0%	56%	$4,952	0.00024	33,199,947	97	62	11	919	12%	24%	18%	33%	42%	41%	1.2%	12%
F-Class CT	$4,499	6.7%	30%	$5,413	0.00018	17,975,167	80	22	758	900	28%	40%	46%	17%	21%	24%	0.8%	11%
Convert F.B. Culley 3 to Natural Gas by 2027	$4,503	6.8%	27%	$5,316	0.00015	15,506,174	60	21	469	941	26%	39%	32%	19%	22%	27%	0.6%	12%
Convert F.B. Culley 3 to Natural Gas by 2030	$4,508	7.0%	27%	$5,332	0.00016	16,953,911	60	21	469	941	25%	35%	32%	19%	22%	27%	0.6%	12%
Replace FB Culley 3 with Storage and Solar	$4,539	7.7%	29%	$5,416	0.00018	15,917,099	101	137	720	671	38%	43%	49%	13%	21%	17%	1.7%	8%
Convert F.B. Culley 3 to Natural Gas by 2027 with 2027 wind and solar	$4,559	8.2%	25%	$5,347	0.00014	15,382,405	60	21	469	941	24%	31%	32%	20%	24%	27%	0.6%	13%
Replace FB Culley 3 with Storage and Wind	$4,580	8.7%	26%	$5,328	0.00015	15,931,427	74	9	769	671	27%	35%	33%	15%	21%	21%	0.7%	12%
Business as Usual	$4,581	8.7%	35%	$5,486	0.00025	23,897,336	90	74	480	941	31%	35%	36%	14%	21%	19%	0.9%	10%
Diversified Renewables	$4,583	8.8%	25%	$5,313	0.00015	15,763,426	89	71	669	671	25%	31%	30%	18%	22%	24%	1.1%	9%
Diversified Renewables (Early Storage & DG Solar)	$4,676	11.0%	25%	$5,408	0.00015	15,766,880	94	81	659	671	25%	34%	30%	18%	22%	24%	1.2%	9%

1: Total energy generation from coal and gas / total fleet generation from 2023 - 2042

2: Average CO_2e from generation / average fleet generation from 2030 - 2042

CO_2e shown in metric tons

3: Sum of CO_2e emissions from 2023 - 2042

4: Maximum seasonal capacity deficit in summer/winter from 2030 - 2042

5: Average MW of installed battery, CT, recip capacity from 2030 - 2042

6: Average MW of dispatchable resources from 2030 - 2042

7: Average GWh energy market interaction / total energy + sales from 2023 - 2042

Near Term: 2026 - 2030

Long Term: 2031 - 2042

8: Average capacity market purchases / coincident peak demand from 2023 - 2042

Sensitivities

- Sensitivities were performed to further understand how portfolios cost or resource selection may be impacted by changes in the future
- Base modeling assumed CenterPoint would be able to fully monetize 100% of the ITC
  - Based on sensitivity analysis the impact to portfolio NPVs by adjusting the ITC monetization is minimal
- Due to uncertainty about future resources ability to capitalize on the IRA energy community bonus, it was not included in base modeling assumptions.
  - Based on the sensitivity analysis this adder would have a limited impact on portfolio NPV
- If storage capacity accreditation decreases, portfolios which include storage as a resource must either rely more on market capacity or add additional resources. The costs associated with storage capacity accreditation declining from 95% to 75% over the study period would increase portfolios that include 200MW+ of storage by at least 2%
- To evaluate the cost risk of increased emissions regulations set by the New Source Performance Standards 111(B), all 10 portfolios were run through 200 different simulations, of which 80 included a carbon tax, each of the portfolios saw a 16% - 26% increase in NPV with the inclusion of additional emissions regulation

Q&A

Next Steps

Matt Rice

Short Term Action Plan

- Near-Term:
  - File for 2021-2023 DSM Extension for 2024
  - Submit IRP
  - Begin class 1 engineering study
- Mid-term:
  - File 2025-2027 DSM Plan
  - Issue Renewable RFP for renewable projects
  - File Certificate of Public Convenience and Necessity (CPCN) for F.B. Culley 3 conversion
  - Bring Generation Transition Phase 1 projects online
  - File Certificate of Public Convenience and Necessity (CPCN) for renewables

Q&A

CenterPoint 2022 IRP
4th Stakeholder Meeting Minutes Q&A
April 26, 2023, 1:00 pm – 3:00 pm CDT

Richard Leger (Senior Vice President, CenterPoint Energy) – Welcome, Safety Message

Matt Rice (Director, Indiana Electric Regulatory and Rates, CenterPoint Energy) – Discussed the meeting agenda, guidelines for the meeting, discussed updates from the last stakeholder meeting including feedback, and the 2022/2023 IRP status update.

Matt Rice - Presented the preferred portfolio.

- Slide 20 Portfolio CO_2 Emissions:
    - Question: Do you know if those numbers on gas take adequate account for methane leakage in the production?
        - Response: The numbers in the scorecard account for CO_2 Equivalent coming from the stack based on a recommendation in a previous meeting. This slide specifically is just looking at CO_2 stack emissions not CO_2 equivalent. There is not a big difference in these numbers.
- General Questions:
    - Questions: Is the option to convert CTs to Combined Cycle in reference to AB Brown?
        - Response: Yes.
    - Question: Will you file a Certificate of Public Convenience and Necessity (CPCN) to convert FB Culley to gas before the next IRP?
        - Yes.
    - Question: Is the conversion of FB Culley 3 to a combined cycle natural gas plant?
        - No. It will be the same steam turbine; however, it will be fired with natural gas instead of coal.

Drew Burczyk (Project Manager, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the risk analysis modeling and portfolio creation and selection during the analysis.

- General Questions:
    - Question: For Warrick 4, which is being exited, are there going to be any power purchase agreements with it going forward? How about OVEC?
        - Response: We still plan to exit Warrick 4 at the end of the year. There's currently no contract or PPA beyond 2023. We are contractually bound for OVEC for another 15 to 20 years.
    - Question: Is the price of the wholesale market affected in the stochastic analysis?
        - Response: Yes, the different scenarios all had a different price forecast, and then within the stochastics the price forecasts were further varied depending on the scenario and input drivers.
    - Question: With regulations at the federal level expected to tighten natural gas emissions, have you figured emissions costs into this analysis?

        - Response: We have scenarios that include CO_2 tax. There are risks associated with future regulations, and those are captured by the CO_2 tax in the stochastics.

<u>Matt Lind</u> (Director, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the risk analysis scorecard along with the metrics and results.

- Slide 51 Balanced Scorecard Environmental Sustainability:
    - Question: Is this slide showing the CO_2e emissions only when CenterPoint is burning it, or does this include a full life cycle of the emissions?
        - Response: It is just the direct emissions from the generation in the scenario.

<u>Matt Rice</u> – Discussed the next steps of the IRP process including the short-term action plan.

- General Questions and comments:
    - Question: Do you have a figure or percentage to show how much renewables have increased, in terms of portion of the portfolio, from the last IRP to this one?
        - Response: By 2030, 80% of energy produced will be from wind and solar resources.
- Feedback From Tech-to-Tech Participant:
    - Comment: Thank you for the data sharing you have done throughout this process, and for the willingness to answer our questions. I felt like this process was much improved over the last IRP.

Attachment 4.1 2022-2023 CEI South Long-Term Electric Energy and Demand Forecast Report

CEI SOUTH CENTERPOINT ENERGY INDIANA SOUTH

2022 Long-Term Electric Energy and Demand Forecast Report

Submitted to:
CEI CenterPoint Energy Indiana South

Prepared by:

Itron

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May 15, 2023

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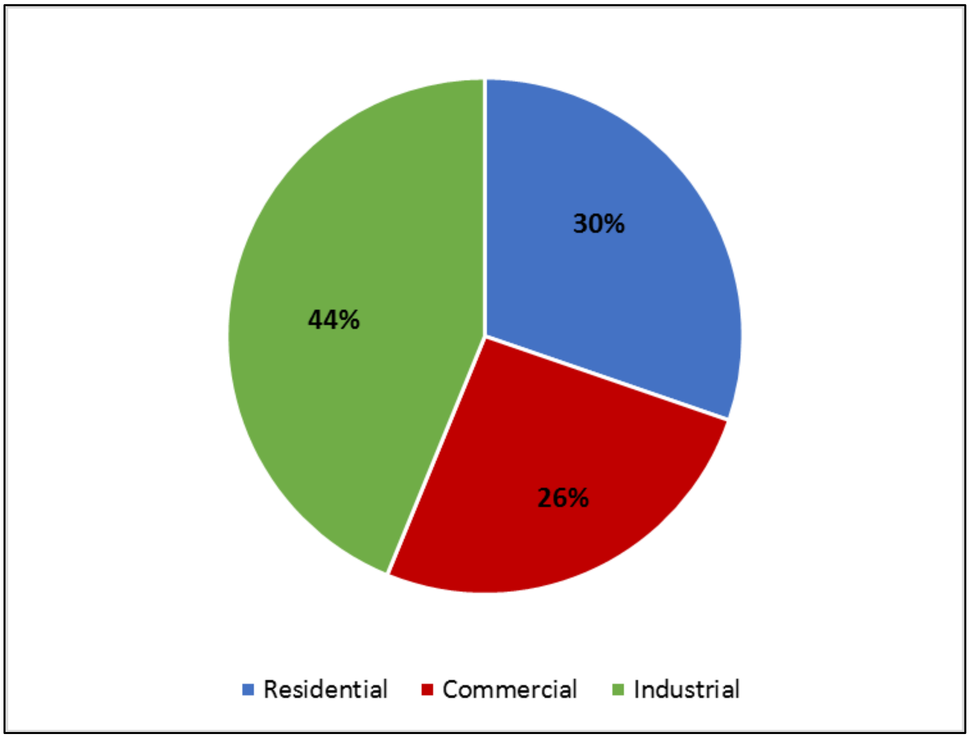
1 OVERVIEW

Itron, Inc. was contracted by CEI South to develop a long-term load forecast to support the 2022/2023 Integrated Resource Plan. The energy and demand forecasts extend through 2042. The forecast is based on a bottom-up approach that starts with residential, commercial, industrial, and street lighting load forecasts that then drive system energy and peak demand. This forecast is then adjusted for behind-the-meter (BTM) solar and electric vehicle load projections. This report presents the results, assumptions, and overview of the forecast methodology.

1.1 CEI SOUTH SERVICE AREA

CEI South serves approximately 150,000 electric customers in Southwest Indiana; Evansville is the largest city within the service area. The service area includes a large industrial base with industrial customers accounting for approximately 44% of sales in 2021. The residential class accounts for 30% of sales with approximately 131,000 customers and the commercial class 26% of sales; there are approximately 19,000 nonresidential customers. System 2021 energy requirements are 4,822 GWh with system peak reaching 1,003MW. Figure 1 shows 2021 class-level sales distribution.

FIGURE 1: 2021 ANNUAL SALES BREAKDOWN



CEI South has seen moderate customer growth with residential customer growth averaging 0.6% per year since 2011. Despite COVID-19's impact, customer growth has continued to increase with 2020 and 2021 showing the strongest growth of the last ten years; since 2018, customer growth has averaged 0.8% per year. Residential customer growth averaged 0.6% since 2011, and 0.8% since 2018.

Commercial customer annual growth averaged 0.4% since 2011, and 0.6% since 2018. Prior to the economic slowdown brough on by the COVID-19 pandemic, GDP averaged 1.9% annual growth, following the 2020 drop and subsequent 2021 rebound, long-term GDP growth is forecasted at 1.4% average annual rate with employment growth of 0.4% per year.

Despite moderate economic and customer growth, system energy and peaks demand have been declining. Energy requirements and demand have declined 0.4% annually since 2011. Energy efficiency gains have been a big factor. COVID-19 had a significant impact resulting in an 8.0% drop in 2020 commercial sales.

Since 2011 weather-normalized residential average use has declined on average 1.2% per year resulting in 0.6% annual decline in residential sales. Commercial sales have also been falling; normalized sales have declined 1.3% per year, this is heavily impacted by the drop in 2020 sales. The industrial sector is the only sector showing growth with industrial sales averaging 0.7% average annual growth[1].

1.2 FORECAST SUMMARY

While DSM activity has had a significant impact on sales, for the IRP filing, the energy and demand forecasts do not include future DSM energy savings; DSM savings are treated as a resource on a consistent and comparable basis to supply side resources in as part of the integrated resource planning process. Excluding DSM but including the impact of future customer-owned generation and electric vehicles results in energy requirements and summer peak demand increases of 0.7% per year and winter peak demand growth of 0.5% per year. Most of the growth is after 2030 as electric vehicles begin to have a significant impact on load. Table 1-1 shows the CEI South energy and demand forecasts. CEI South's utility scale solar and other distributed generation are not included in this report but are accounted for within the IRP.

[1] Excludes a large customer with cogeneration

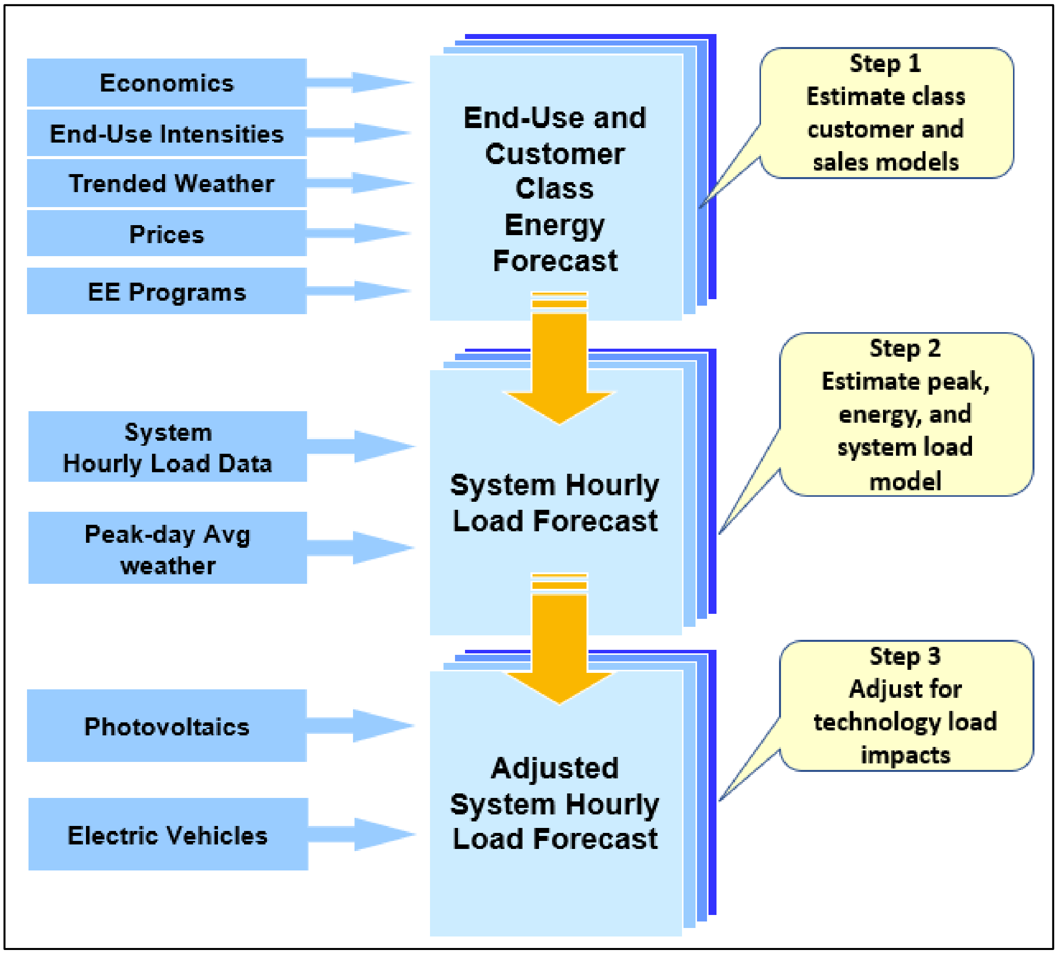
TABLE 1-1: ENERGY AND DEMAND FORECAST (EXCLUDING DSM PROGRAM SAVINGS)

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2022	4,815,801		1,019		802	
2023	4,725,478	-1.9%	1,010	-0.9%	738	-8.0%
2024	5,163,907	9.3%	1,087	7.6%	812	10.0%
2025	5,152,172	-0.2%	1,087	0.0%	810	-0.2%
2026	5,153,363	0.0%	1,088	0.1%	811	0.1%
2027	5,164,632	0.2%	1,092	0.3%	813	0.3%
2028	5,178,436	0.3%	1,095	0.3%	816	0.4%
2029	5,175,063	-0.1%	1,095	0.0%	816	0.0%
2030	5,178,761	0.1%	1,096	0.1%	817	0.2%
2031	5,199,311	0.4%	1,100	0.3%	821	0.5%
2032	5,238,099	0.7%	1,105	0.5%	828	0.9%
2033	5,254,460	0.3%	1,110	0.4%	831	0.4%
2034	5,277,650	0.4%	1,114	0.4%	836	0.5%
2035	5,304,282	0.5%	1,120	0.6%	841	0.6%
2036	5,345,573	0.8%	1,128	0.7%	849	1.0%
2037	5,377,724	0.6%	1,136	0.7%	855	0.7%
2038	5,418,448	0.8%	1,145	0.8%	862	0.9%
2039	5,455,497	0.7%	1,154	0.8%	869	0.8%
2040	5,493,803	0.7%	1,162	0.7%	875	0.8%
2041	5,518,739	0.5%	1,169	0.6%	880	0.5%
2042	5,551,532	0.6%	1,177	0.6%	886	0.7%
CAGR 22-42		0.7%		0.7%		0.5%

2 FORECAST APPROACH

The long-term energy and demand forecasts are based on a build-up approach. End-use sales derived from the customer class sales models (residential, commercial, industrial, and street lighting) drive system energy and peak demand. Energy requirements are calculated by adjusting sales forecast upwards for line losses. Peak demand is forecasted through a monthly peak-demand linear regression model that relates peak demand to peak-day weather conditions and end-use energy requirements (heating, cooling, and other use). System energy and peak are adjusted for residential and commercial PV adoption and EV charging impacts. Figure 2 shows the general framework and model inputs.

FIGURE 2: CLASS BUILD-UP MODEL



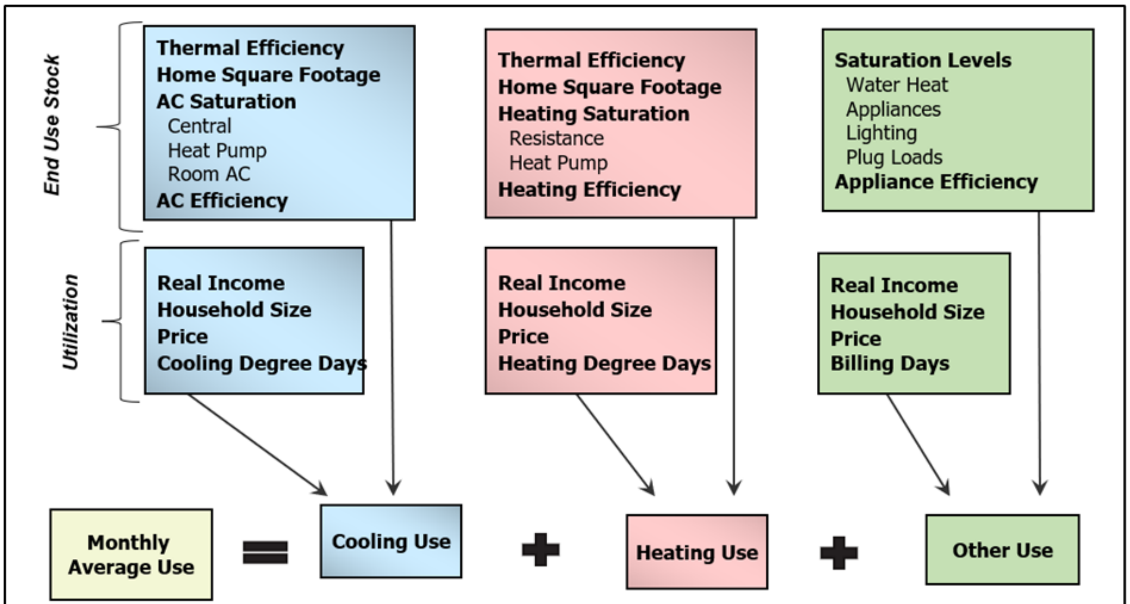
In the long-term, both economic growth and structural changes drive energy and demand requirements. Structural changes include the impact of residential appliance saturation and efficiency trends, housing square footage and thermal shell efficiency, and commercial building end-use intensity trends. The long-term structural drivers are captured in the residential and commercial sales forecast models through a specification that combines economic drivers with structural drivers. This type of model is known as a Statistically Adjusted End-Use (SAE) model. The SAE model variables explicitly incorporate end-use saturation and efficiency projections, as well as changes in population, economic conditions, price, and weather. Both residential average use and commercial sales are forecasted using an SAE specification.

Industrial sales are forecasted using a two-step approach, which includes a generalized econometric model that relates industrial sales to seasonal patterns and industrial economic activity. Streetlight sales are forecasted using a simple trend and seasonal model.

2.1 RESIDENTIAL MODEL

Residential average use and customers are modeled separately. The residential sales forecast is then generated as the product of the average use and customer forecasts. Average use is defined in terms of the average customer's heating (XHeat), cooling (XCool), and other use (XOther) electricity requirements. Figure 3 shows the residential average use model.

FIGURE 3: RESIDENTIAL SAE MODEL



$$AvgUse_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_e \times EE_m$$

The end-use model variables XCool, XHeat, and XOther are constructed by integrating the end use intensity trends with weather, economics, and price. For XOther, it is the monthly number of billing days that impacts much of the monthly short-term variation. The model coefficients – $\mathbf{b_c}$, $\mathbf{b_h}$ and $\mathbf{b_o}$ are estimated using linear regression; the model is estimated over the period January 2011 to June 2022. The model also includes a separate DSM variable (EE) to capture the historical DSM savings that are not captured in the primary model variables. Figure 4 to Figure 6 show the constructed monthly heating, cooling, and other end-use variables. Appendix B shows the end-use variable calculations.

FIGURE 4: RESIDENTIAL XHEAT

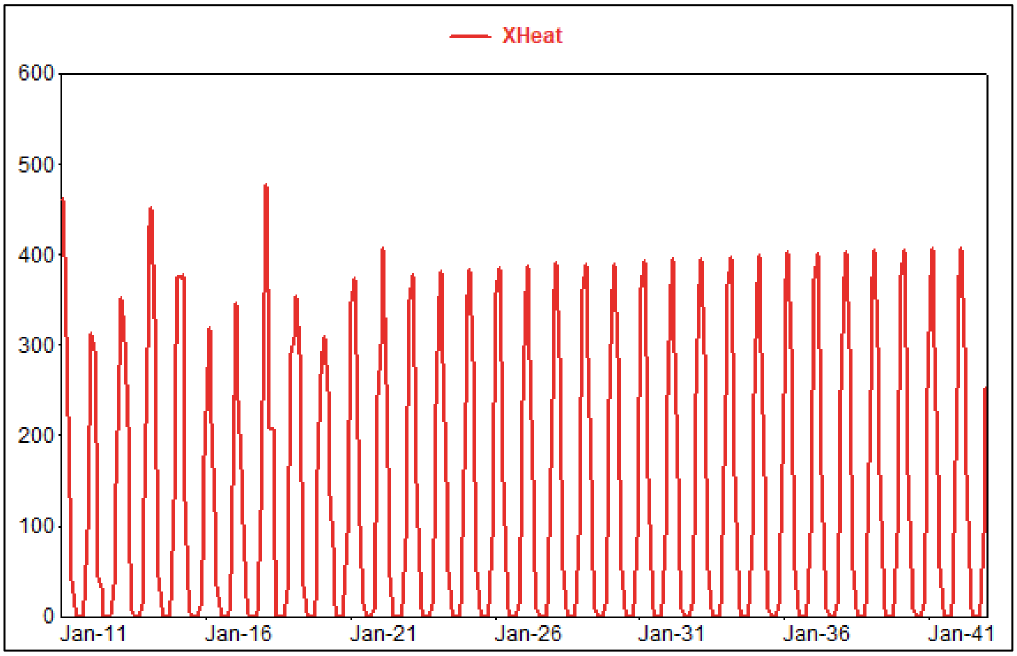


FIGURE 5: RESIDENTIAL XCOOL

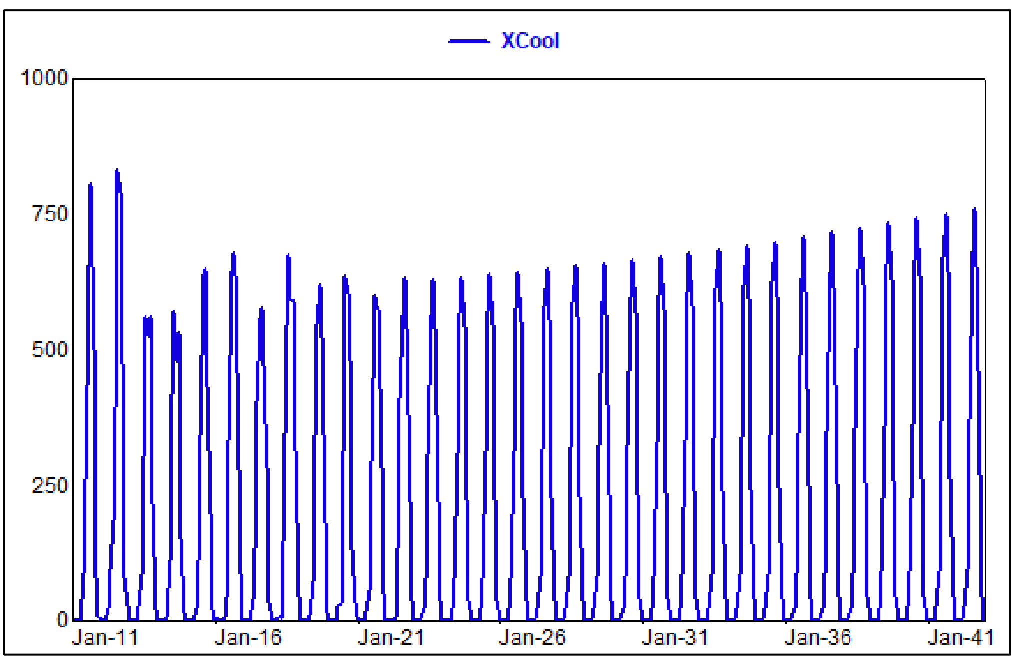


FIGURE 6: RESIDENTIAL XOTHER

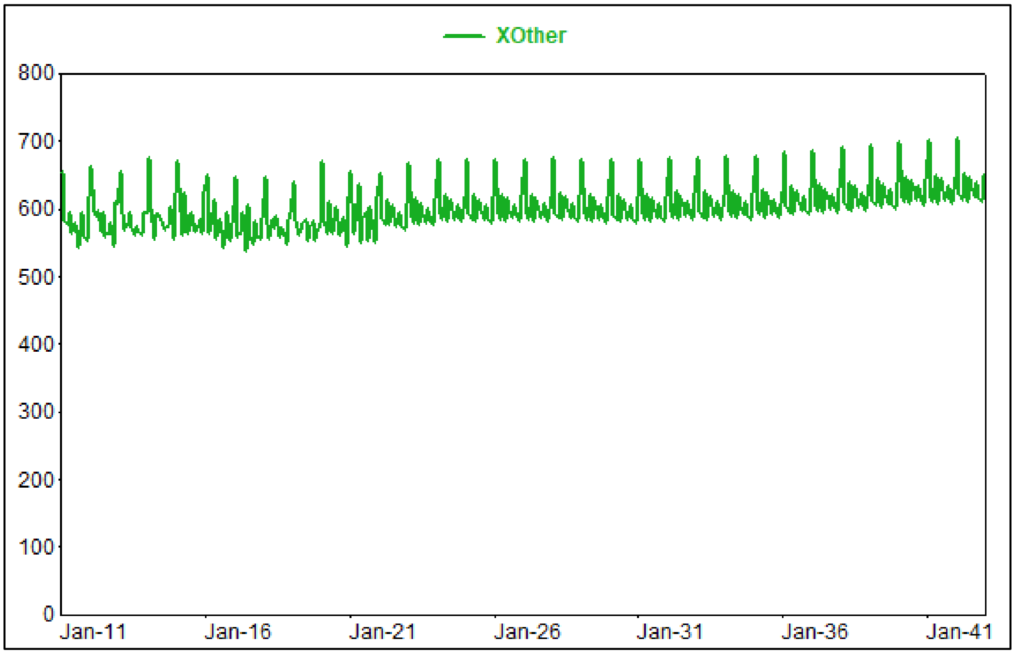
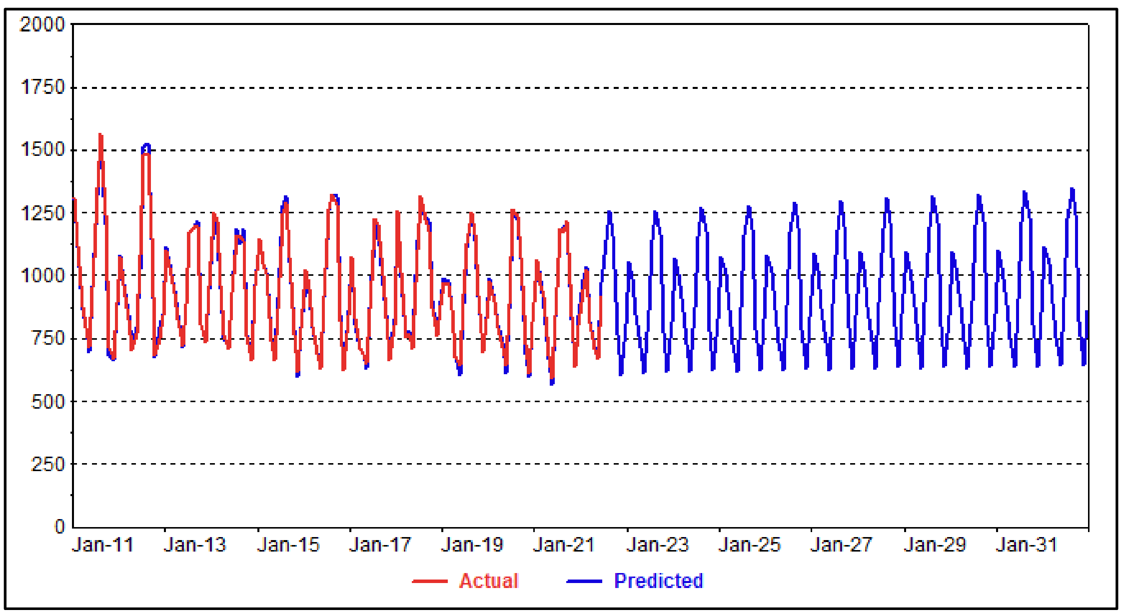


Figure 7 shows the model results.

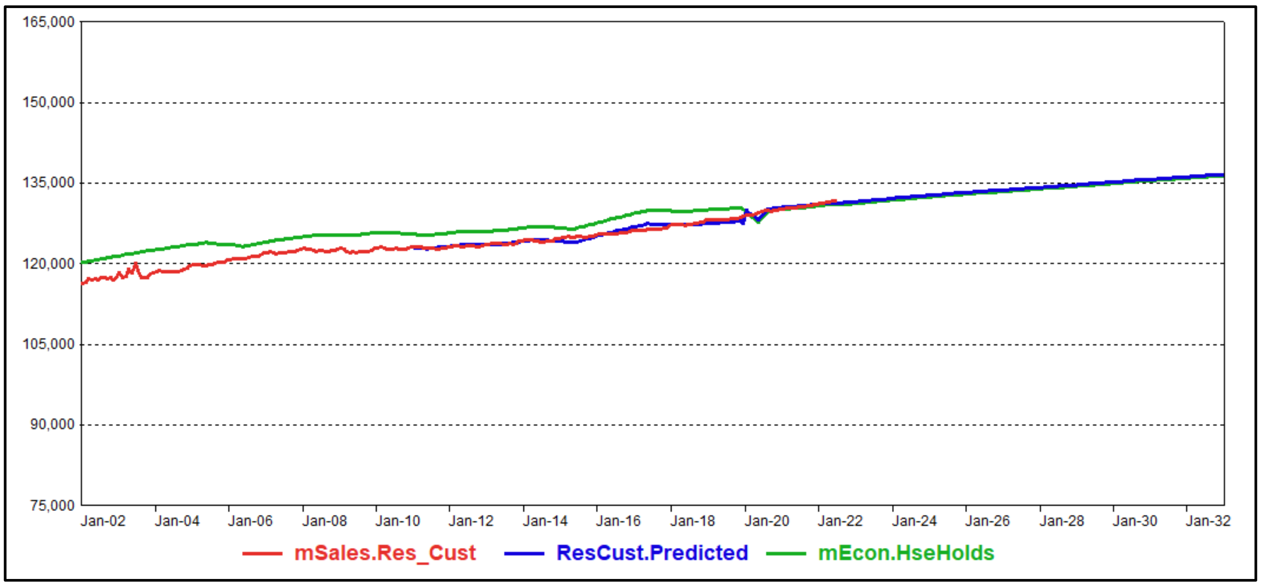
FIGURE 7: RESDENTIAL AVERAGE USE – BASELINE FORECAST



The model also includes a COVID variable to account for the jump in residential average use in 2020. The variable is based on Google Mobility Data that measured cell phone activity near the home. Average use has trended back to pre-COVID levels with businesses and schools reopening. Customer use remains slightly elevated as some households continue to work at home either fulltime or as part of new Hybrid work schedules. Overall, the SAE model explains historical average use variation and trend well with an Adjusted R^2 of 0.98 and in-sample Mean Absolute Percent Error (MAPE) of 1.9%. Model coefficients are statistically significant at the 95% level of confidence and higher. Model coefficients and statistics are provided in Appendix A. Excluding DSM, Baseline average use increases 0.4% annually through the forecast period.

The customer forecast is based on a monthly regression model that relates the number of customers to Evansville MSA (Metropolitan Statistical Area) household projections. We assume that over the long-term, service area customer growth will track household growth in the larger MSA. Figure 8 shows actual and predicted and the number of households in the MSA.

FIGURE 8: CUSTOMER FORECAST



Not surprisingly, there is a strong correlation between MSA level households and the Company. Through the COVID period, however, the Company continued to add customers while the number of households dropped slightly. Given CEI South serves most of the MSA, we assume that customer growth will continue to track household projections with 0.4% long-term annual customer growth.

With 0.4% customer and average use growth, sales average 0.8% annual growth. Table 2-1 shows the residential sales forecast before solar and EV adjustments.

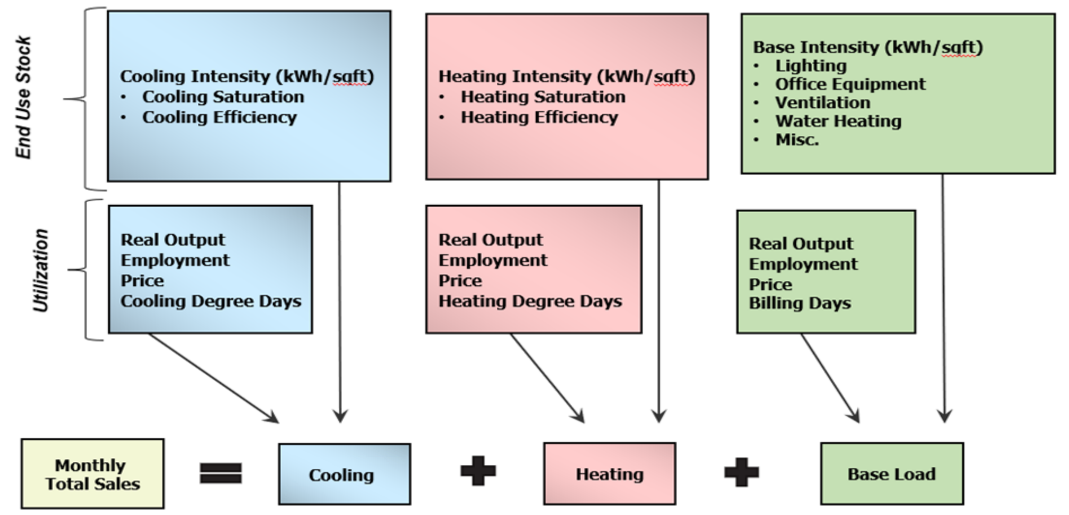
TABLE 2-1: RESIDENTIAL BASELINE FORECAST (EXCLUDES FUTURE DSM)

Year	Sales (MWh)		Customers		AvgUse (kWh)	
2022	1,457,502		131,442		11,089	
2023	1,432,970	-1.7%	131,833	0.3%	10,870	-2.0%
2024	1,453,295	1.4%	132,438	0.5%	10,973	1.0%
2025	1,463,031	0.7%	133,003	0.4%	11,000	0.2%
2026	1,474,875	0.8%	133,494	0.4%	11,048	0.4%
2027	1,484,864	0.7%	133,957	0.3%	11,085	0.3%
2028	1,498,661	0.9%	134,431	0.4%	11,148	0.6%
2029	1,502,827	0.3%	134,931	0.4%	11,138	-0.1%
2030	1,511,813	0.6%	135,435	0.4%	11,163	0.2%
2031	1,524,392	0.8%	135,908	0.3%	11,216	0.5%
2032	1,542,615	1.2%	136,393	0.4%	11,310	0.8%
2033	1,551,854	0.6%	136,899	0.4%	11,336	0.2%
2034	1,566,061	0.9%	137,470	0.4%	11,392	0.5%
2035	1,581,042	1.0%	137,981	0.4%	11,458	0.6%
2036	1,601,937	1.3%	138,451	0.3%	11,570	1.0%
2037	1,616,478	0.9%	138,926	0.3%	11,636	0.6%
2038	1,636,273	1.2%	139,494	0.4%	11,730	0.8%
2039	1,655,551	1.2%	140,052	0.4%	11,821	0.8%
2040	1,675,499	1.2%	140,549	0.4%	11,921	0.8%
2041	1,688,869	0.8%	141,009	0.3%	11,977	0.5%
2042	1,705,768	1.0%	141,424	0.3%	12,061	0.7%
CAGR 22-42		0.8%		0.4%		0.4%

2.2 COMMERCIAL MODEL

The commercial sales model is also estimated using an SAE specification. Figure 9 shows the commercial SAE model.

FIGURE 9: COMMERCIAL SAE MODEL



$$MWh_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_e \times EE_m$$

Commercial end-use intensities are mapped to cooling (XCool), heating (XHeat), and other use (XOther). A linear regression model is used to estimate a set of coefficients that calibrate the end-use variables to commercial monthly sales. The model includes historical cumulative DSM savings (EE) to account for EE savings above captured by the model and a COVID model variable based on Google Mobility Data.

The model input variables include end-use intensities, HDD, CDD, number of billing days, price, and economic deriver that incorporates MSA GDP, employment, and number of households. Figure 10 to Figure 12 show the model variables. The specific variable construction is provided in Appendix C.

FIGURE 10: COMMERCIAL XHEAT

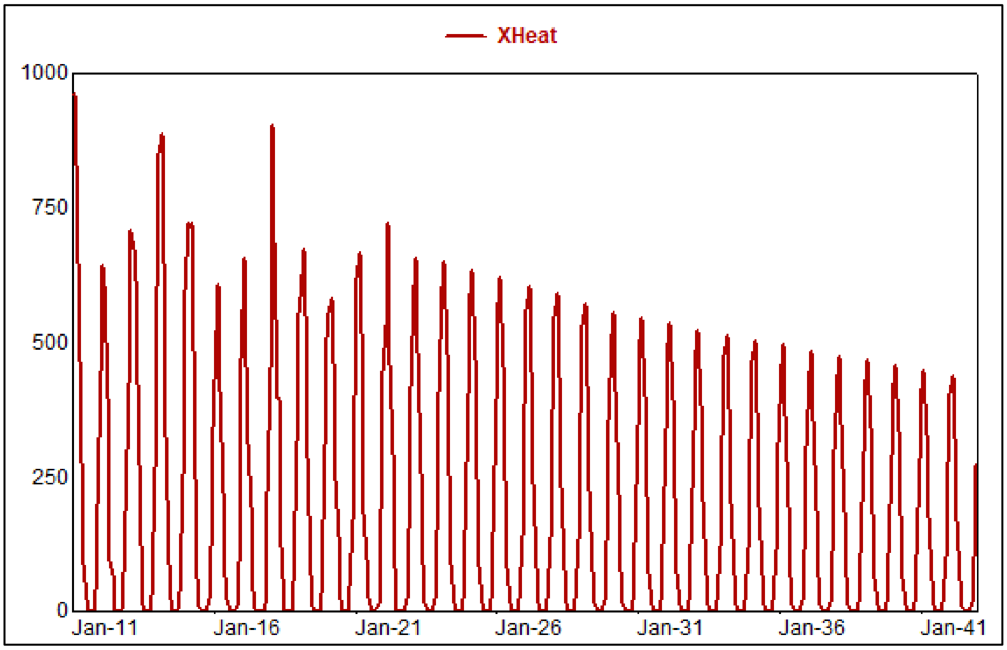


FIGURE 11: COMMERCIAL XCOOL

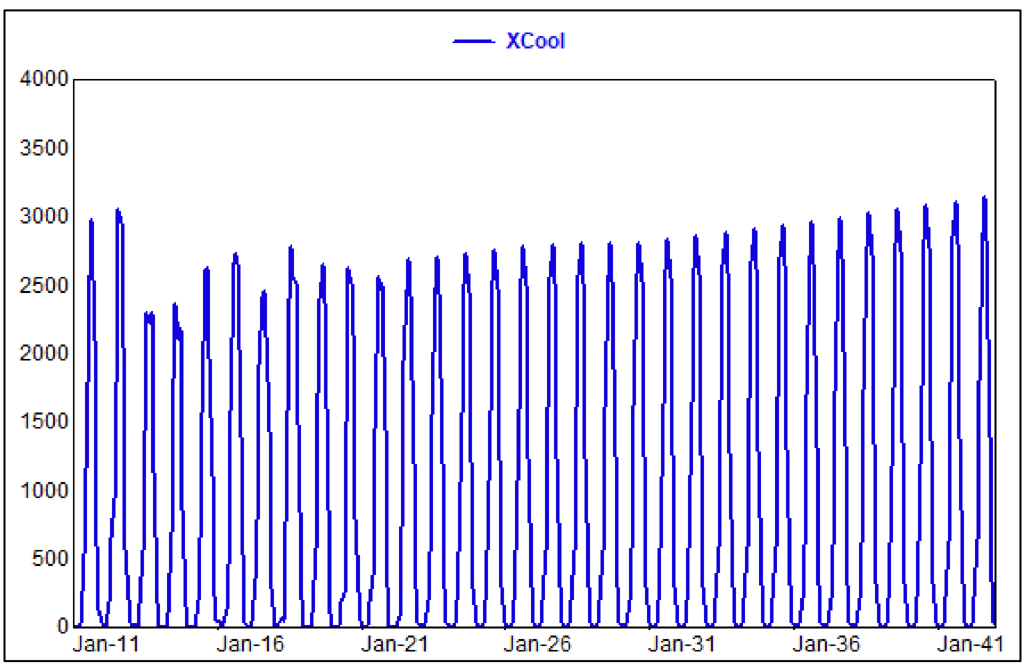


FIGURE 12: COMMERCIAL XOTHER

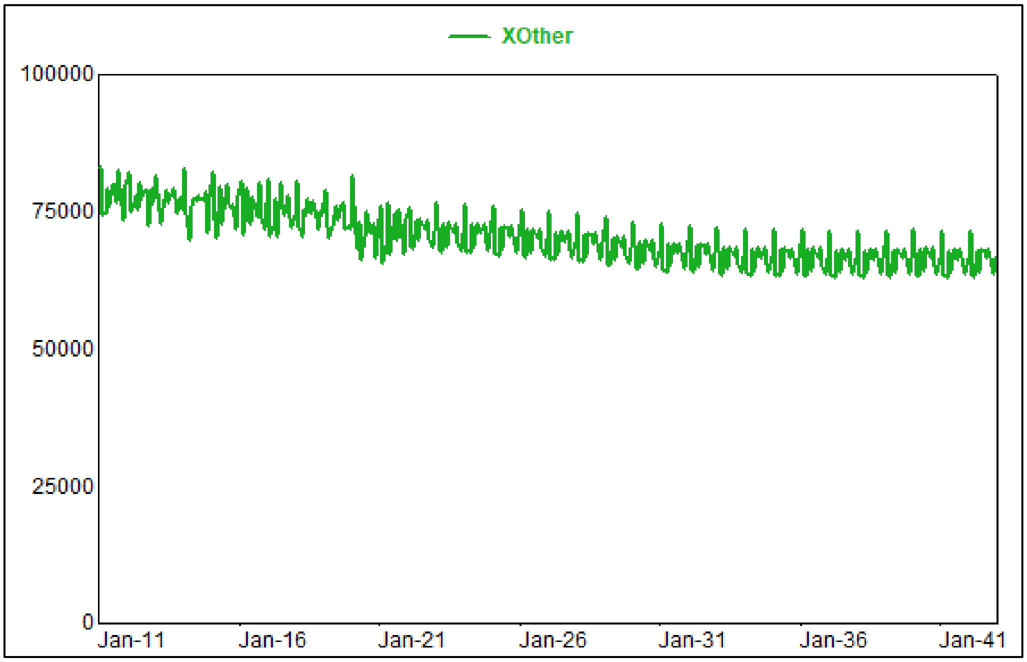
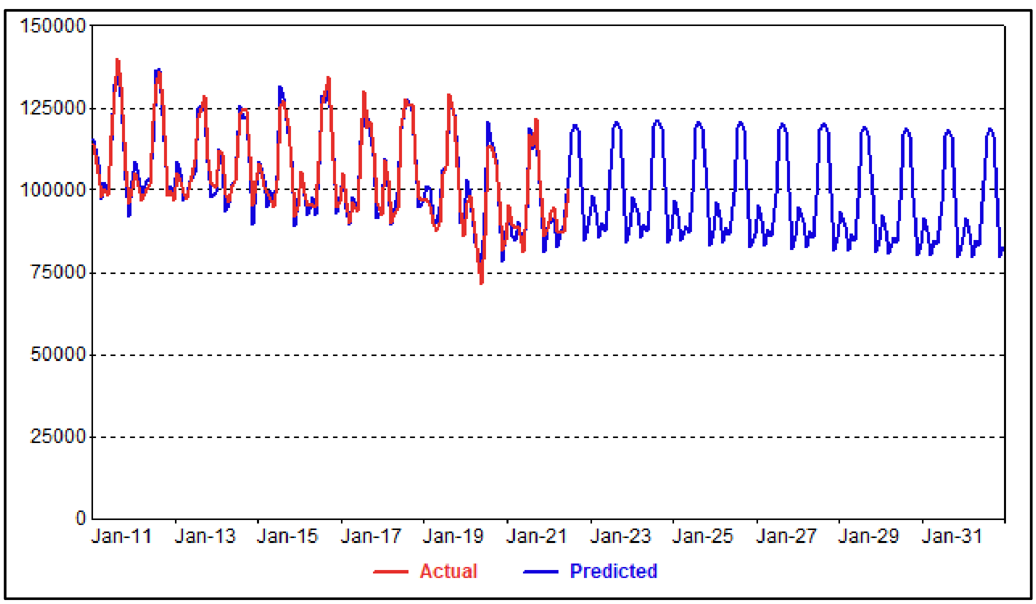


Figure 13 shows model results.

FIGURE 13: COMMERCIAL SALES BASELINE FORECAST



The commercial model specification explains historical sales variation and growth relatively well with an Adjusted R^2 of 0.95 and an in-sample MAPE of 2.3%. The model is estimated with monthly billed sales data from January 2011 to June 2022. Since 2020, commercial sales have been recovering but never get back to pre-COVID levels as work activity continues at elevated levels from home. Model statistics are included in Appendix A. The forecast reflects expected increase in efficiency due to standards, but does not include future DSM, solar self-generation, or electric vehicle charging.

TABLE 2-2: COMMERCIAL BASELINE FORECAST

Year	Sales (MWh)		Customers	
2022	1,174,529		19,085	
2023	1,186,006	1.0%	19,104	0.1%
2024	1,185,789	0.0%	19,159	0.3%
2025	1,179,712	-0.5%	19,211	0.3%
2026	1,173,134	-0.6%	19,257	0.2%
2027	1,166,780	-0.5%	19,299	0.2%
2028	1,162,204	-0.4%	19,343	0.2%
2029	1,151,379	-0.9%	19,389	0.2%
2030	1,141,452	-0.9%	19,435	0.2%
2031	1,135,443	-0.5%	19,479	0.2%
2032	1,134,151	-0.1%	19,523	0.2%
2033	1,128,122	-0.5%	19,570	0.2%
2034	1,126,279	-0.2%	19,622	0.3%
2035	1,124,869	-0.1%	19,669	0.2%
2036	1,126,986	0.2%	19,713	0.2%
2037	1,125,074	-0.2%	19,756	0.2%
2038	1,126,752	0.1%	19,809	0.3%
2039	1,128,542	0.2%	19,860	0.3%
2040	1,131,894	0.3%	19,906	0.2%
2041	1,129,874	-0.2%	19,948	0.2%
2042	1,131,305	0.1%	19,986	0.2%
CAGR 22-42		-0.2%		0.2%

2.3 INDUSTRIAL MODEL

The industrial sales forecast is developed with a two-step approach. The first three years of the forecast are derived from CEI South's expectation of specific customer activity. The forecast after the first three years is based on the industrial forecast model. CEI South determines a baseline volume based on historical consumption use. The baseline use is then adjusted to reflect expected closures and expansions. Near-term sales are also adjusted for the addition of new industrial customers. After the third year, the forecast is derived from the industrial sales model; forecasted growth is applied to the third-year industrial sales forecast.

The industrial sales model is a generalized linear regression model that relates monthly historical industrial billed to manufacturing employment, manufacturing output, CDD, and monthly binaries to capture seasonal load variation and shifts in sales data. The industrial economic driver is a weighted combination of manufacturing employment and manufacturing output. The industrial economic ($IndVar$) variable is defined as:

$$IndVar_{ym} = \left(ManufEmploy_{ym}^{0.67}\right) \times \left(ManufOutput_{ym}^{0.33}\right)$$

Where:

y = year
m = month

The imposed weights are determined by evaluating in-sample and out-of-sample statistics for alternative weighting schemes. The model Adjusted R^2 is 0.52 with a MAPE of 5.9%. The relatively low Adjusted R^2 and high MAPE, in comparison to the residential and commercial models, are a result of the large month-to-month variations in industrial billing data. The industrial model excludes sales to one of CEI South's largest customers, which is currently meeting most of its load through onsite cogeneration.

Excluding DSM, industrial sales average 1.1% annual growth, driven by the addition of a large new customer in 2023. After 2025, industrial sales average 0.3% annual growth. Table 2-3 summarizes the industrial sales forecast.

TABLE 2-3: INDUSTRIAL FORECAST (EXCLUDING FUTURE DSM, PV, EV)

Year	Sales (MWh)	
2022	1,854,221	
2023	1,793,424	-3.3%
2024	2,189,424	22.1%
2025	2,179,125	-0.5%
2026	2,178,524	0.0%
2027	2,187,341	0.4%
2028	2,194,083	0.3%
2029	2,198,120	0.2%
2030	2,200,486	0.1%
2031	2,206,341	0.3%
2032	2,212,215	0.3%
2033	2,219,392	0.3%
2034	2,223,532	0.2%
2035	2,229,140	0.3%
2036	2,239,930	0.5%
2037	2,252,123	0.5%
2038	2,264,307	0.5%
2039	2,274,252	0.4%
2040	2,282,621	0.4%
2041	2,288,406	0.3%
2042	2,294,127	0.2%
CAGR 22-42		1.1%

2.4 STREET LIGHTING MODEL

Streetlight sales are fitted with a regression model with a trend and monthly binaries. Streetlighting sales are decreasing 0.7% annually throughout the forecast period. Table 2-4 shows the streetlight forecast.

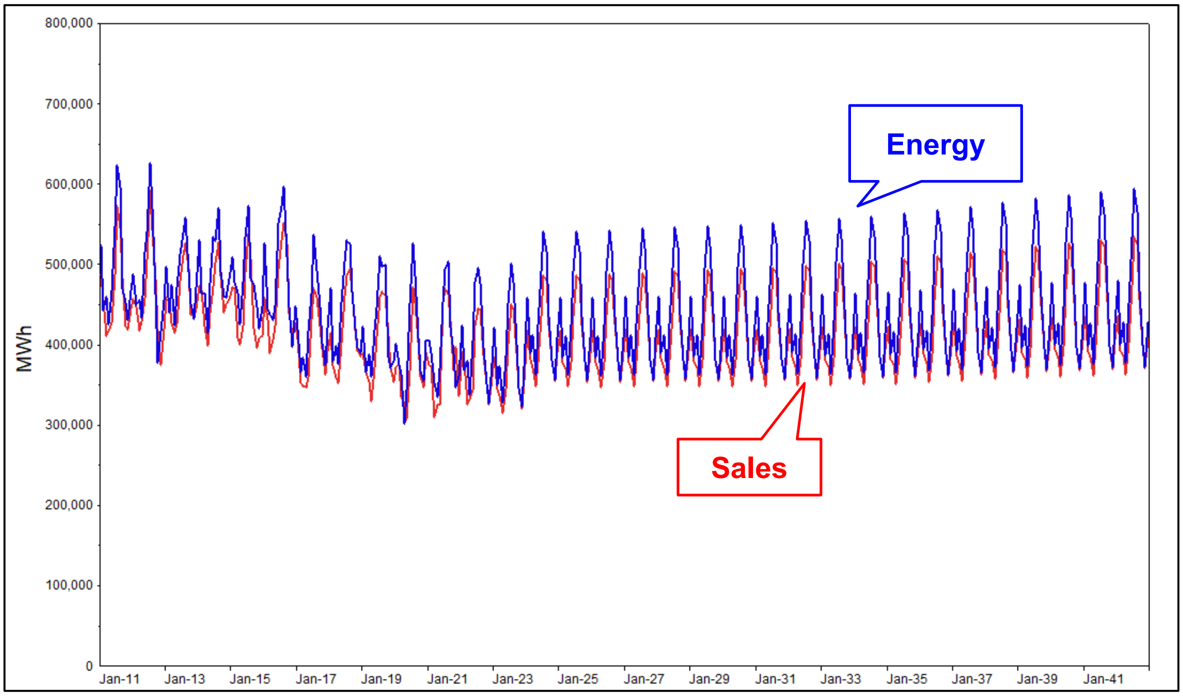
TABLE 2-4: STREET LIGHTING FORECAST

Year	Sales (MWh)	
2022	20,509	
2023	20,561	0.3%
2024	20,424	-0.7%
2025	20,287	-0.7%
2026	20,149	-0.7%
2027	20,012	-0.7%
2028	19,874	-0.7%
2029	19,737	-0.7%
2030	19,600	-0.7%
2031	19,462	-0.7%
2032	19,325	-0.7%
2033	19,188	-0.7%
2034	19,050	-0.7%
2035	18,913	-0.7%
2036	18,775	-0.7%
2037	18,638	-0.7%
2038	18,501	-0.7%
2039	18,363	-0.7%
2040	18,226	-0.7%
2041	18,088	-0.8%
2042	17,951	-0.8%
CAGR 22-42		-0.7%

2.5 ENERGY FORECAST MODEL

The baseline energy forecast is derived directly from the sales forecast by applying a monthly energy adjustment factor to the sales forecast. The energy adjustment factor includes line losses and any differences in timing between monthly sales estimates and delivered energy (*unaccounted for energy*). Monthly adjustment factors are calculated based on the historical relationship between energy and sales. Figure 14 shows the monthly sales and energy forecast, excluding the impact of future DSM, PV or electric vehicles.

FIGURE 14: ENERGY AND SALES FORECAST (EXCLUDING DSM, EV, PV)



2.6 PEAK FORECAST MODEL

The baseline system peak forecast is derived through a monthly peak regression model that relates peak demand to heating, cooling, and base load requirements:

$$Peak_{ym} = B_0 + B_1 HeatVar_{ym} + B_2 CoolVar_{ym} + B_3 BaseVar_{ym} + e_{ym}$$

Where:

y = year

m = month

End-use energy requirements are estimated from class sales forecast models.

Heating and Cooling Model Variables

The residential and commercial SAE model coefficients are used to isolate historical and projected weather-normal heating and cooling requirements. Heating requirements are interacted with peak-day HDD and cooling requirements with peak-day CDD; this interaction allows peak-day weather impacts to change over time with changes in heating and cooling requirements. The peak model heating and cooling variables are calculated as:

- $HeatVar_{ym} = HeatLoadIdx_{ym} \times PkHDD_{ym}$
- $CoolVar_{ym} = CoolLoadIdx_{ym} \times PkCDD_{ym}$

Where $HeatLoadIdx_{ym}$ is an index of total system heating requirements in year y and month m and $CoolLoadIdx_{ym}$ is an index of total system cooling requirements in year y and month m. $PkHDD_{ym}$ is the peak-day HDD in year y and month m and $PkCDD_{ym}$ is the peak-day CDD in year y and month m.

Figure 15 and Figure 16 show *HeatVar* and *CoolVar*. The variation in the historical period is a result of variation in peak-day HDD and CDD.

FIGURE 15: PEAK-DAY HEATING VARIABLE

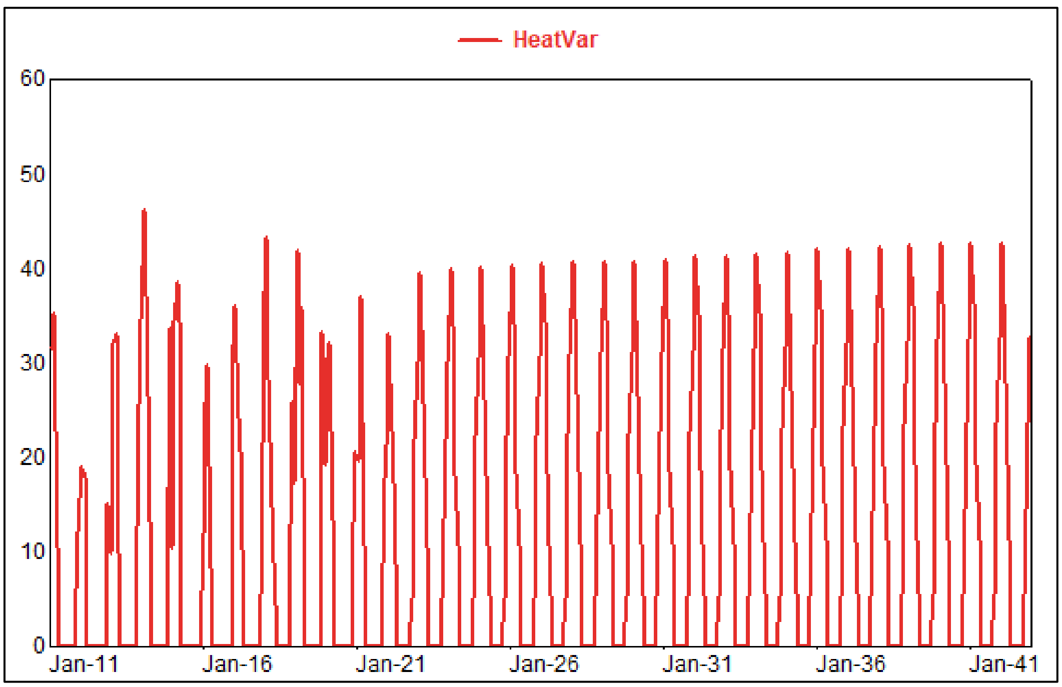
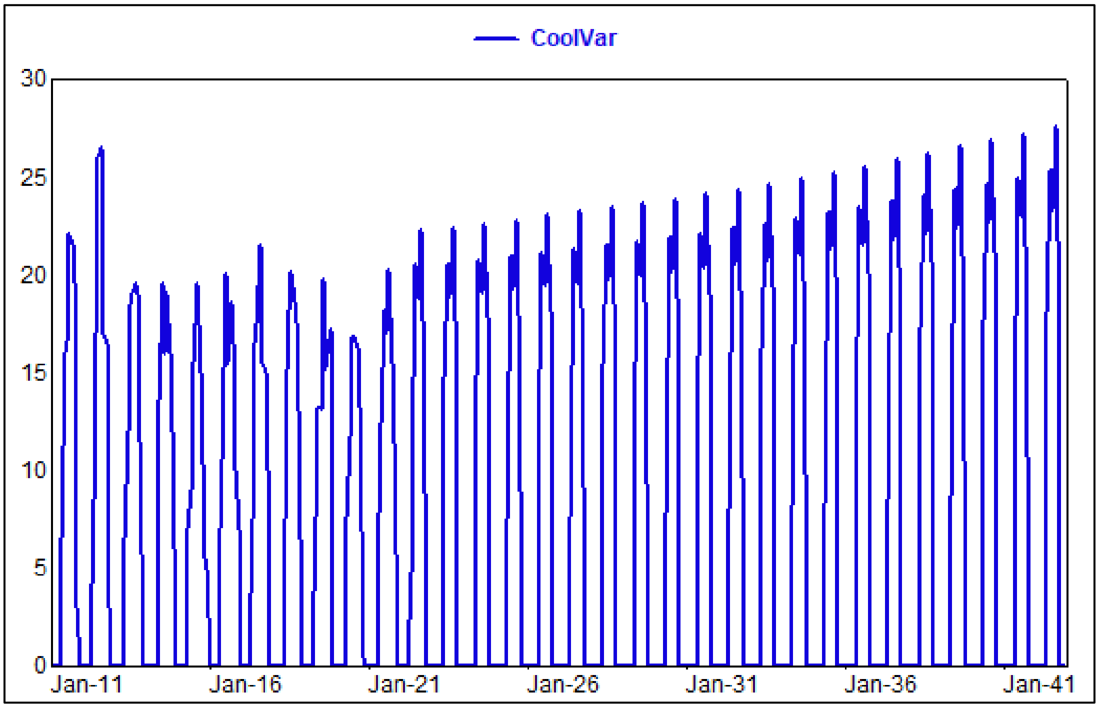


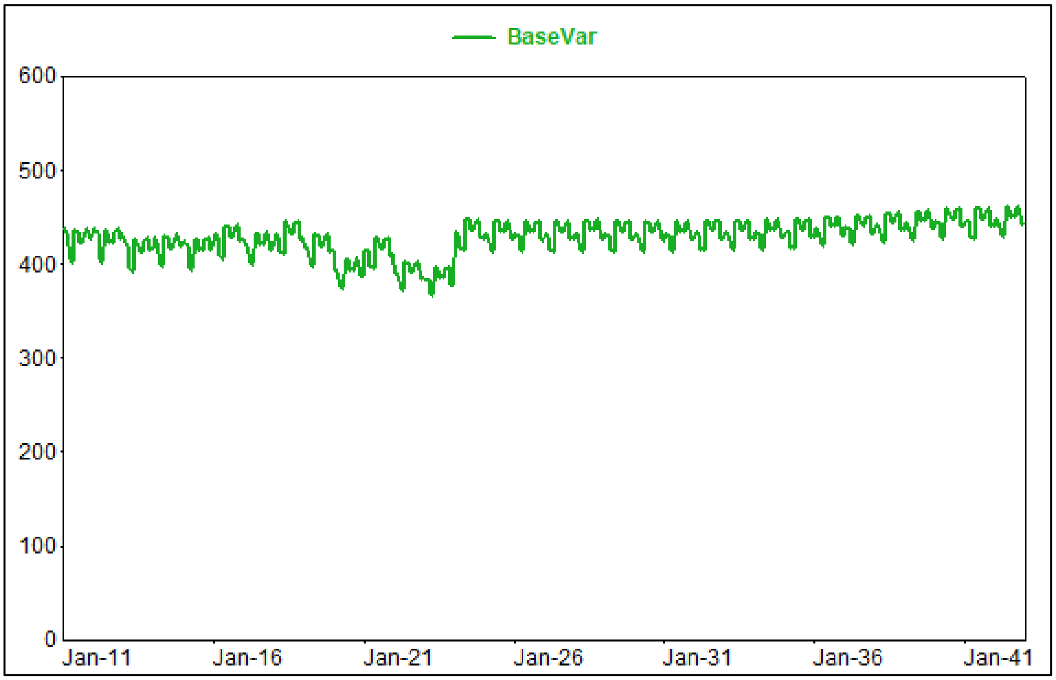
FIGURE 16: PEAK-DAY COOLING VARIABLE



Base Load Variable

The base-load variable ($BaseVar_{ym}$) captures non-weather sensitive load at the time of the monthly peak. Monthly base-load estimates are calculated by allocating non-weather sensitive energy requirements to end-use estimates at the time of peak. End-use allocation factors are based on a set of end-use profiles developed by Itron. Figure 17 shows the non-weather sensitive peak-model variable.

FIGURE 17: PEAK-DAY BASE-USE VARIABLE

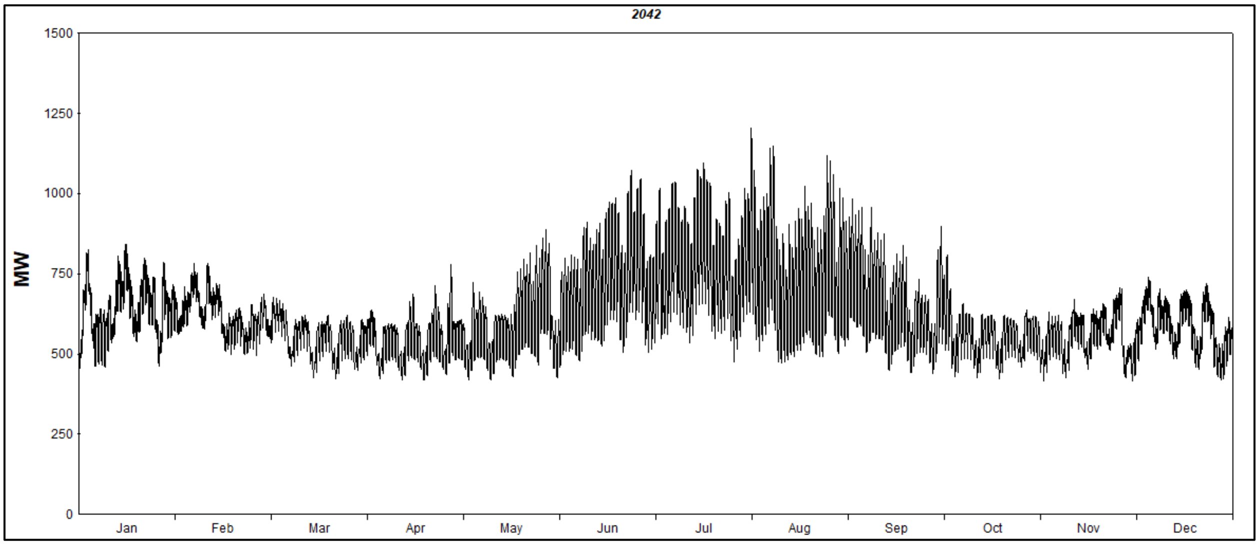


Model Results

The peak model is estimated over the period January 2011 to June 2022. The model explains monthly peak variation well with an adjusted R^2 of 0.93 and an in-sample MAPE of 3.57%. The end-use variables – *HeatVar*, *CoolVar*, and *BaseVar* are all highly statistically significant. Model statistics and parameters are included in Appendix A.

The baseline energy and peak forecast, excluding DSM, PV, and electric vehicles, are combined with a system hourly load profile to derive the baseline hourly load forecast. Figure 18 shows the hourly load forecast for 2042.

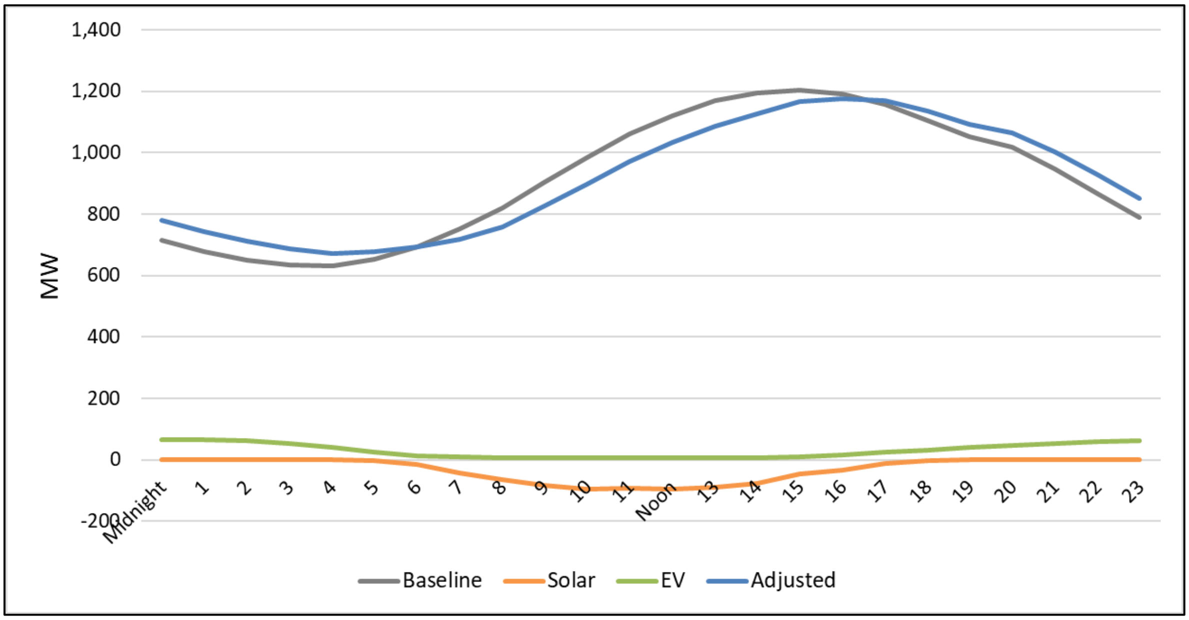
FIGURE 18: BASELINE SYSTEM HOURLY LOAD FORECAST



2.7 ADJUSTED ENERGY & PEAK FORECAST

The final adjusted energy and peak forecast is produced by adding additional solar and electric vehicle hourly load forecasts to the baseline forecast. This approach is a change from the prior IRP in which coincident peak load factors for PV and electric vehicles were used to estimate peak impacts. The advantage of the hourly approach is the ability to capture the changing impact of PV and electric vehicles with changes to the timing of the system peak. Due to the additional PV and electric vehicles, the summer system peak shifts forward one hour beginning in 2034, reducing the impact of solar. Figure 19 shows the baseline hourly load, PV and electric vehicles loads, and final adjusted system load for a summer peak day in 2042.

FIGURE 19: ADJUSTED SYSTEM HOURLY LOAD FORECAST



The final adjusted energy and peak forecast is derived from the adjusted hourly system forecast. Table 2-5 shows adjusted energy and peak demand forecast.

TABLE 2-5: ENERGY AND PEAK FORECAST (EXCLUDING DSM)

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2022	4,815,801		1,019		802	
2023	4,725,478	-1.9%	1,010	-0.9%	738	-8.0%
2024	5,163,907	9.3%	1,087	7.6%	812	10.0%
2025	5,152,172	-0.2%	1,087	0.0%	810	-0.2%
2026	5,153,363	0.0%	1,088	0.1%	811	0.1%
2027	5,164,632	0.2%	1,092	0.3%	813	0.3%
2028	5,178,436	0.3%	1,095	0.3%	816	0.4%
2029	5,175,063	-0.1%	1,095	0.0%	816	0.0%
2030	5,178,761	0.1%	1,096	0.1%	817	0.2%
2031	5,199,311	0.4%	1,100	0.3%	821	0.5%
2032	5,238,099	0.7%	1,105	0.5%	828	0.9%
2033	5,254,460	0.3%	1,110	0.4%	831	0.4%
2034	5,277,650	0.4%	1,114	0.4%	836	0.5%
2035	5,304,282	0.5%	1,120	0.6%	841	0.6%
2036	5,345,573	0.8%	1,128	0.7%	849	1.0%
2037	5,377,724	0.6%	1,136	0.7%	855	0.7%
2038	5,418,448	0.8%	1,145	0.8%	862	0.9%
2039	5,455,497	0.7%	1,154	0.8%	869	0.8%
2040	5,493,803	0.7%	1,162	0.7%	875	0.8%
2041	5,518,739	0.5%	1,169	0.6%	880	0.5%
2042	5,551,532	0.6%	1,177	0.6%	886	0.7%
CAGR 22-42		0.7%		0.7%		0.5%

3 CUSTOMER OWNED DISTRIBUTED GENERATION

The energy and peak forecasts incorporate the impact of customer-owned photovoltaic systems. System adoption is expected to increase as solar system costs decline, which is partially offset by changes in net metering laws that will credit excess generation at a rate lower than retail rates in the future. As of June 2022, CEI South had 950 residential solar customers and 136 commercial solar customers, with an approximate installed capacity of 22.6 MW.

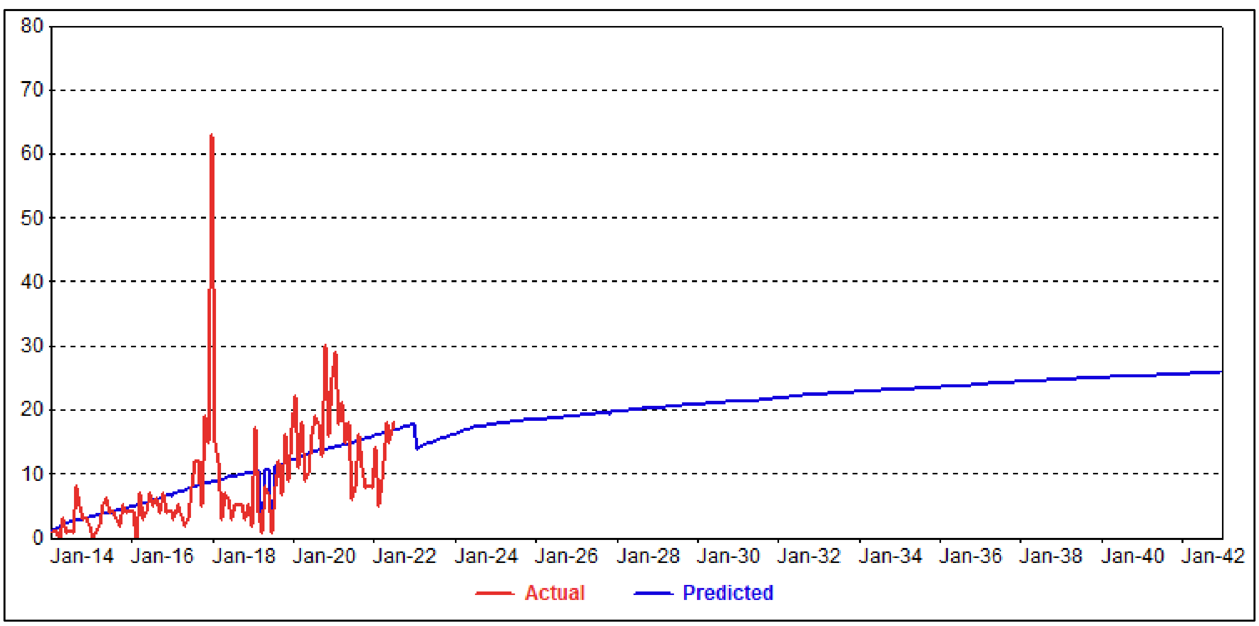
3.1 MONTHLY ADOPTION MODEL

The primary factor driving system adoption is a customer's return-on-investment. A simple payback model is used as proxy. Simple payback reflects the length of time needed to recover the cost of installing a solar system - the shorter the payback, the higher the system adoption rate. From the customer's perspective, this is the number of years until electricity is "free." Simple payback also works well to explain leased system adoption as return on investment drives the leasing company's decision to offer leasing programs. Solar investment payback is calculated as a function of system costs, federal and state tax credits and incentive payments, retail electric rates, and treatment of excess generation (solar generation returned to the grid). The payback calculation incorporates the impact of switching from net metering to Excess Distributed Generation (EDG). Federal investment tax credits were extended in accordance with the Inflation Reduction Act.

One of the most significant factors driving adoption is declining system costs; costs have continued declining over the last five years. In 2010, residential solar system cost was approximately $8.00 per watt. By 2020 costs had dropped to $3.80 per watt. For the forecast period, we assume system costs continue to decline 10% annually through 2024 and an additional 3% annually after 2024.

The solar adoption model relates monthly residential solar adoptions to simple payback. Figure 20 shows the resulting residential solar adoption forecast.

FIGURE 20: RESIDENTIAL SOLAR ADOPTION FORECAST



In the commercial sector, there have been too few adoptions to estimate a robust model; commercial system adoption has been low across the country. Limited commercial adoption reflects higher investment hurdle rates, building ownership issues (i.e., the entity that owns the building often does not pay the electric bill), and physical constraints as to the placement of the system. For this forecast, we assume there continues to be some commercial rooftop adoption by allowing commercial adoption to increase over time, based on the current relationship between commercial and residential adoptions rates. Table 3-1 shows projected solar adoption.

TABLE 3-1: SOLAR CUSTOMER FORECAST

Year	Residential Systems	Commercial Systems	Total Systems
2022	961	141	1,103
2023	1,150	177	1,327
2024	1,345	207	1,552
2025	1,559	240	1,799
2026	1,780	274	2,053
2027	2,008	309	2,317
2028	2,246	346	2,592
2029	2,489	383	2,872
2030	2,741	422	3,162
2031	2,994	461	3,454
2032	3,256	501	3,757
2033	3,524	542	4,066
2034	3,800	585	4,384
2035	4,076	627	4,703
2036	4,358	671	5,029
2037	4,646	715	5,361
2038	4,936	759	5,696
2039	5,236	806	6,041
2040	5,536	852	6,387
2041	5,836	898	6,734
2042	6,144	945	7,089
CAGR 22-42	9.7%	10.0%	9.8%

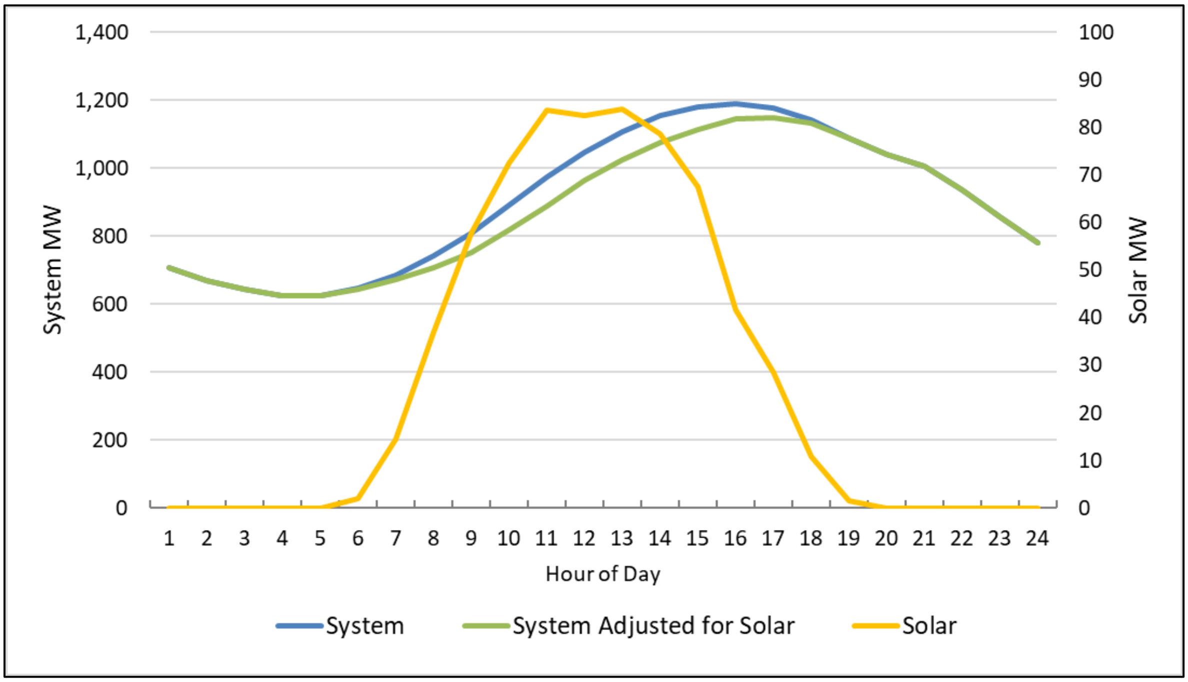
3.2 SOLAR CAPACITY AND GENERATION

Installed solar capacity forecast is the product of the solar customer forecast and average system size (measured in kW). Based on recent solar installation data, the residential average size is 10.4 KW, and commercial average system size is 93.6 KW.

The capacity forecast (MW) is translated into system generation (MWh) forecast by applying monthly solar load factors to the capacity forecast. Monthly load factors are derived from a typical PV load profile for Evansville, IN. The PV shape is from the National Renewable Energy Laboratory (NREL) and represents a typical meteorological year (TMY).

The impact of solar generation on system peak demand is a function of the timing between solar load generation and system hourly demand. Solar output peaks during the mid-day while system peaks later in the afternoon. Figure 21 shows the system profile, solar adjusted system profile, and solar profile for a peak producing summer day.

FIGURE 21: SOLAR HOURLY LOAD IMPACT



Based on system and solar load profiles, 1.0 MW of solar capacity reduces summer peak demand by approximately 0.36 MW through 2033. In 2034 the timing of the system peak shifts forward one hour, resulting in diminished solar impact per installed MW. In 2034 1.0 MW of solar capacity reduces summer peak demand by approximately 0.25 MW.

Table 3-2 shows the incremental new PV capacity forecast, expected annual generation, and demand at time of peak.

TABLE 3-2: NEW SOLAR CAPACITY AND GENERATION

Year	Total Generation MWh	Installed Capacity MW (Aug)	Demand Impact MW
2022	1,537	1.8	0.7
2023	8,211	6.5	2.3
2024	15,018	11.4	4.1
2025	22,399	16.8	6.0
2026	30,039	22.3	8.0
2027	37,960	27.9	10.0
2028	46,299	33.9	12.1
2029	54,615	40.0	14.4
2030	63,335	46.2	16.6
2031	72,103	52.5	18.9
2032	81,374	59.1	21.3
2033	90,470	65.7	23.4
2034	100,029	72.6	17.9
2035	109,595	79.4	19.6
2036	119,645	86.5	21.2
2037	129,363	93.6	23.1
2038	139,416	100.9	24.7
2039	149,790	108.3	26.3
2040	160,542	115.8	28.6
2041	170,589	123.2	30.2
2042	181,272	130.9	32.2

4 ELECTRIC VEHICLE FORECAST

The 2022 Long-Term forecast also includes the impact of electric vehicle adoption. Currently CEI South has relatively few electric vehicles, but this is expected to increase significantly over the next twenty years with improvements in EV technology and declines in battery and vehicle costs. Multiple private and public institutions produce electric vehicle forecasts that vary from conservative to aspirational. Major manufactures have continued to pledge increased EV availability and options. At the time of the forecast CEI South had 238 registered electric vehicles in the counties that CEI South serves: this included full electric (i.e., battery electric vehicles - BEV) as well as plug-in hybrid electric (PHEV) vehicles. The 238 vehicles were comprised of 105 BEVs and 133 PHEVs, with a total of 23 different make/model vehicles represented.

4.1 METHODOLOGY

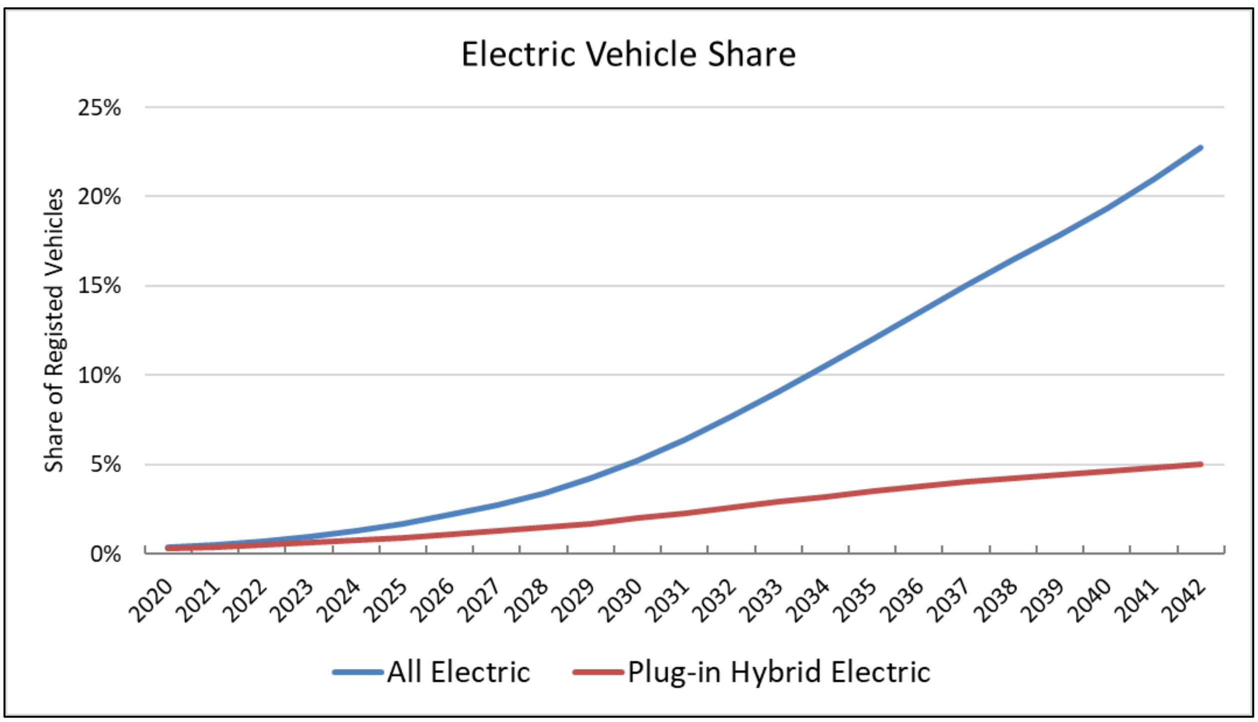
The Energy Information Administration (EIA) Annual Energy Outlook and BloombergNEF are two commonly referenced sources for electric vehicle forecasts. The 2022 Long-Term forecast uses a consensus forecast, averaging the EIA and Bloomberg forecasts to calculate the share of registered light-duty vehicles which are electric, BEV and PHEV. We rely on the EIA's assumption of total light-duty vehicles per household. Using these data, we calculate the average number of cars per household and projected electric vehicle share - BEV and PHEV.

Total service area vehicles are calculated as the product of forecasted customers times EIA projected vehicles per household:

$$Ttl\,Vehicles = \,Custs_{yr} \times EIA\,Vehicle\,Per\,HH_{yr}$$

The number of BEV and PHEV are calculated by applying consensus projected BEV and PHEV saturation to the service area total vehicle forecast. A calibration step is first taken to adjust to the known number of registered EV in CenterPoint's service territory as of 2022. The share of electric vehicles is projected to increase from less than 1% to 23% BEV and 5% PHEV by 2042. The BEV and PHEV saturation forecast is shown in Figure 22.

FIGURE 22: BEV & PHEV MARKET SHARE



The resulting electric vehicle forecast is summarized in Table 4-1:

TABLE 4-1: ELECTRIC VEHICLE FORECAST

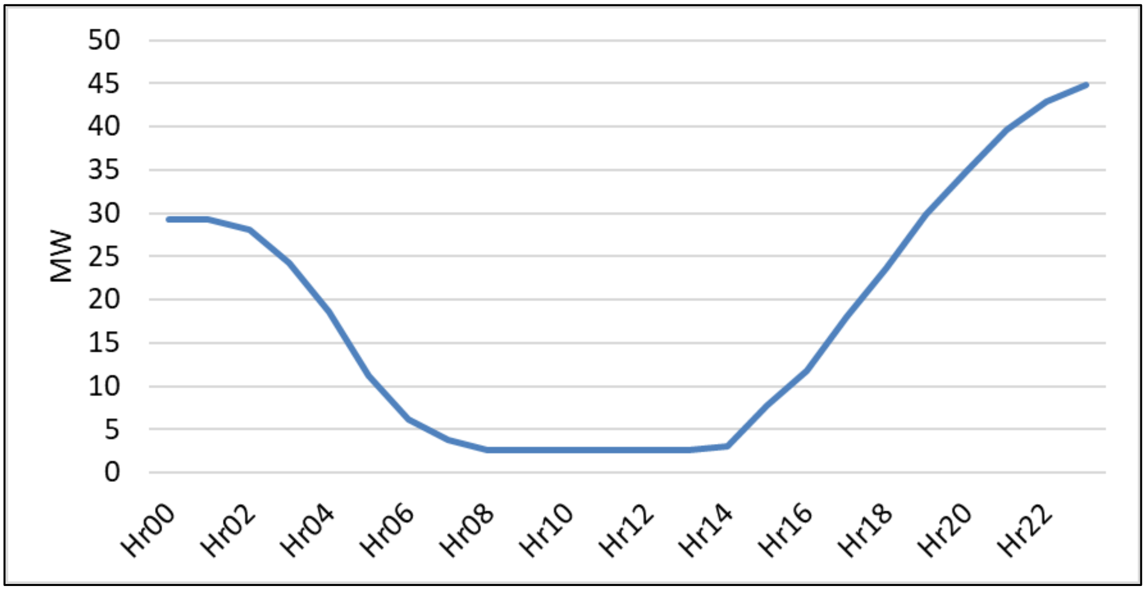
Year	BEV Count	PHEV Count
2022	378	309
2023	585	441
2024	905	629
2025	1,401	898
2026	2,167	1,284
2027	3,354	1,835
2028	4,460	2,266
2029	6,057	2,819
2030	8,412	3,546
2031	11,934	4,514
2032	17,250	5,819
2033	20,422	6,549
2034	23,835	7,287
2035	27,405	8,005
2036	30,950	8,665
2037	34,444	9,261
2038	37,895	9,796
2039	41,251	10,257
2040	44,872	10,728
2041	48,786	11,208
2042	53,012	11,698

4.2 ELECTRIC VEHICLE ENERGY & LOAD FORECAST

Electric vehicles' impact on CEI South's load forecast depends on the amount of energy a vehicle consumes annually and the timing of vehicle charging. BEVs consume more electricity than PHEVs and accounting for this distinction is important. An EV weighted annual kWh use is calculated based on the current mix of EV models. EV usage is derived from manufacturers' reported fuel efficiency to the federal government (www.fueleconomy.gov). The average annual kWh for the current mix of EVs registered in CEI South's service territory is 3,752kWh for BEV and 2,180 kWh for PHEV based on annual mileage of 12,000 miles.

Electric vehicles' impact on peak demand depends on when and where EVs are charged. Since CEI South does not have incentivized BEV/PHEV off-peak charging rates, it is assumed the majority of charging will occur at home in the evening hours. There is a distinction made for weekend and weekday charging. Figure 23 shows the weekday EV charging profile.

FIGURE 23: EV CHARGING PROFILE



The EV load forecast is derived by combining EV energy requirements with the hourly charging load profile, Table 4-2 shows the electric vehicle load forecast.

TABLE 4-2: ELECTRIC VEHICLE LOAD FORECAST

Year	Total Vehicle (MWh)	Summer Peak Impact (MW)	Winter Peak Impact (MW)
2024	691	0.0	0.0
2025	1,808	0.1	0.3
2026	3,500	0.2	0.5
2027	6,069	0.3	0.8
2028	9,972	0.5	1.4
2029	15,909	0.7	2.2
2030	21,251	1.0	3.7
2031	28,809	1.3	5.1
2032	39,752	1.8	7.0
2033	55,841	2.5	9.8
2034	79,773	3.6	13.9
2035	93,941	4.3	16.5
2036	109,076	7.6	19.1
2037	124,785	8.7	25.5
2038	140,262	9.7	28.5
2039	155,391	10.8	31.7
2040	170,208	11.8	34.7
2041	184,488	12.8	37.6
2042	199,831	13.9	40.7
2043	216,348	15.0	44.1
2044	234,119	16.3	47.7

5 FORECAST ASSUMPTIONS

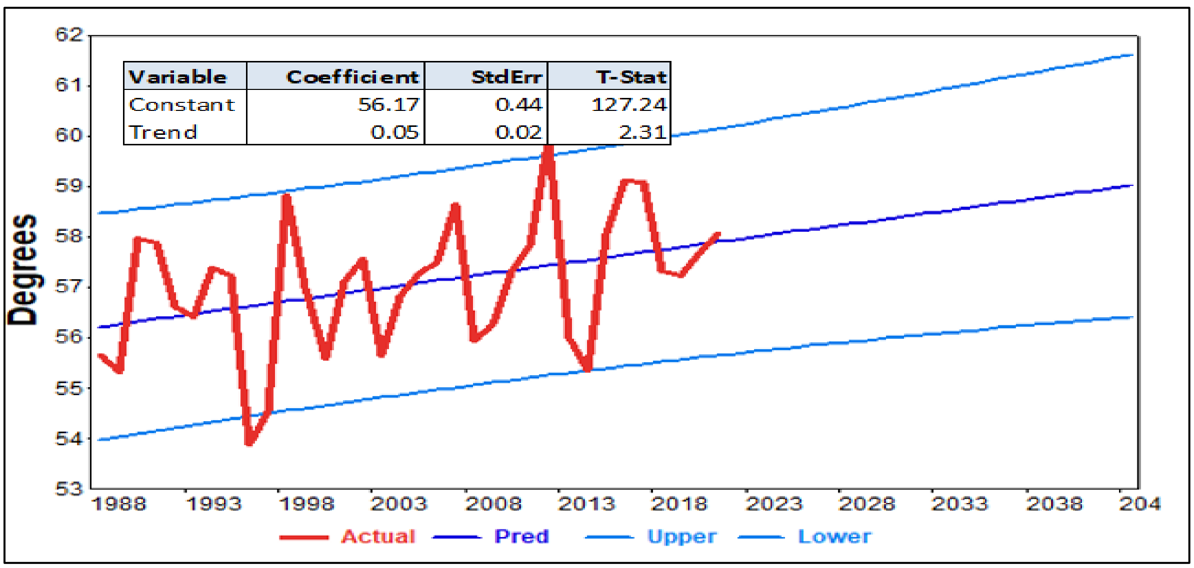
5.1 WEATHER DATA

Historical and normal HDD and CDD are derived from daily temperature data for the Evansville airport. HDD and CDD are often referred to as spline variables as they either take on a positive value or are 0. HDD are positive when temperatures are below a specified temperature reference point and are 0 when temperatures are at or above the temperature reference point. CDD are positive when temperatures are above a temperature reference point and are 0 when temperatures are at or below the temperature reference point. The best temperature breakpoints in terms of statistical model fit varies by customer class. Commercial heating and cooling generally start at lower temperature points than residential. Temperature breakpoints are evaluated as part of the model estimation process. For the residential rate classes, the best temperature breakpoints are 60 degrees for HDD and 65 degrees for CDD. In the non-residential classes, HDD with a 60 degree reference point and CDD with a 60 degree reference point improve the overall model fit.

Traditionally, utilities base their long-term forecast on what the industry calls normal weather. Normal weather is calculated by averaging historical weather usually over a 20-year or 30-year period. Given the large variation in month-to-month and year over year weather conditions, it seemed reasonable to assume that the best representation of current and forecast weather is an average of the past.

Recent studies that Itron and others have conducted have shown that this is probably not the best assumption; over the last fifty years, average temperatures have been increasing. In reviewing historical Evansville weather data, we found a statistically significant positive, but slow, increase in average temperature. Figure 24 shows long-term Evansville temperature trend, and 90% confidence interval.

FIGURE 24: EVANSVILLE TEMPERATURE TRENDS



Since 1988, average annual temperatures have been increasing 0.05 degrees per year, or 0.5 degrees per decade. The trend coefficient is highly statistically significant indicating a high probability of increasing temperatures. This results in HDDs decreasing 0.2% per year while CDDs are increasing 0.5% per year. These trends are incorporated into the forecast. Starting normal HDD are allowed to decrease 0.2% over the forecast period while CDD increase 0.5% per year through 2042. Figure 25 and Figure 26 show historical and forecasted monthly HDD and CDD.

FIGURE 25: HEATING DEGREE DAYS

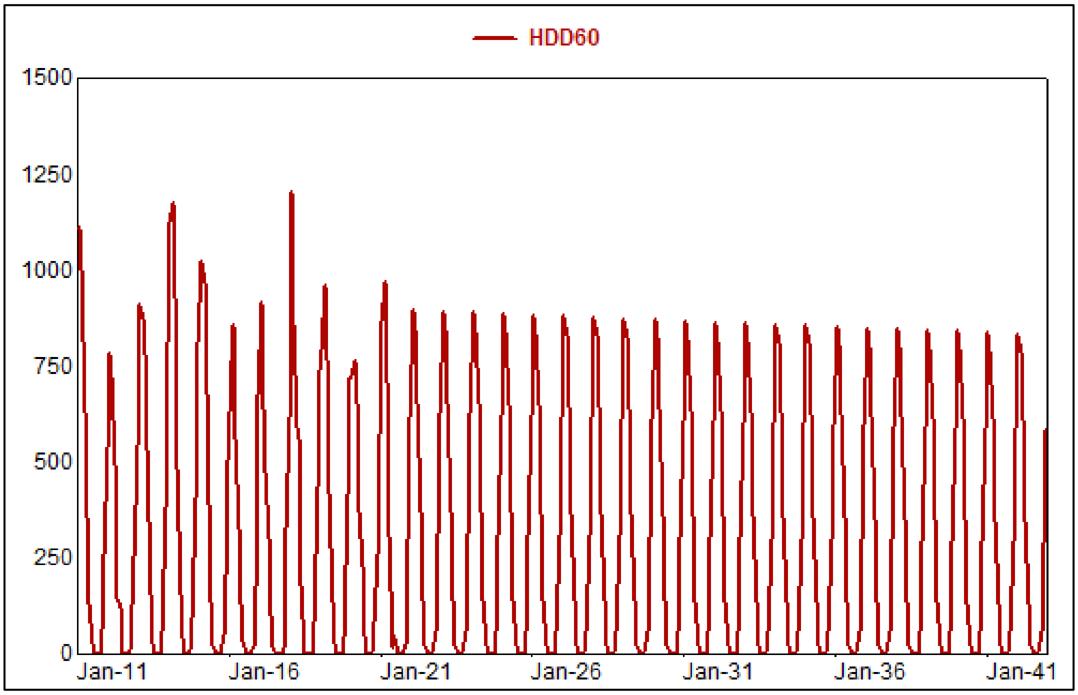
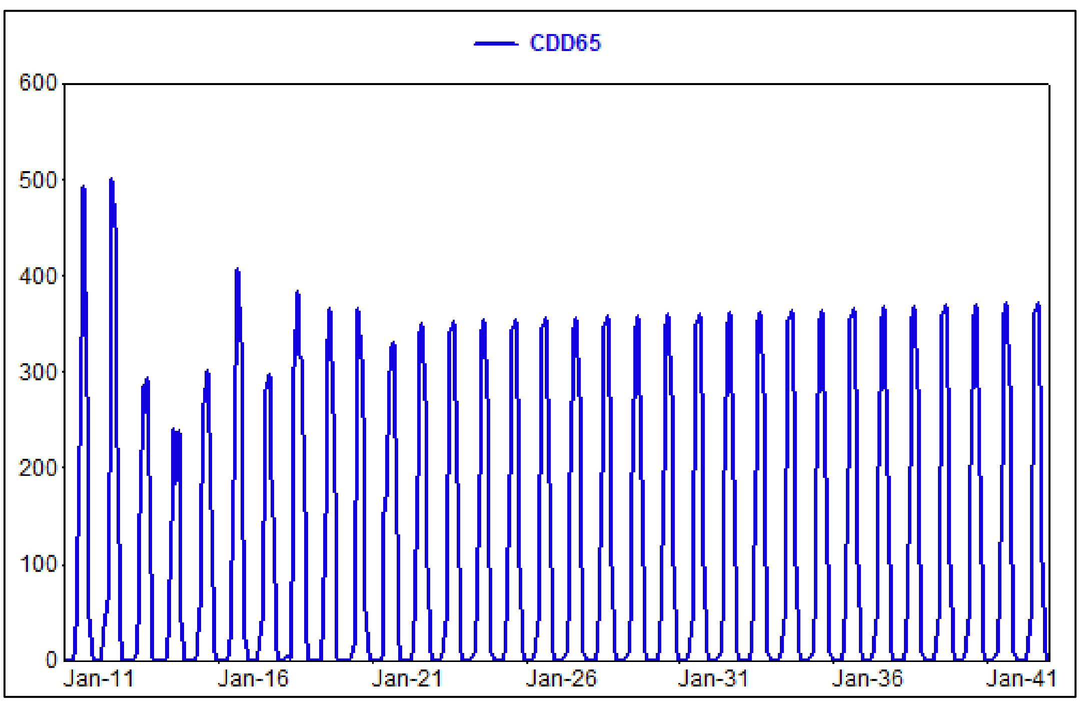


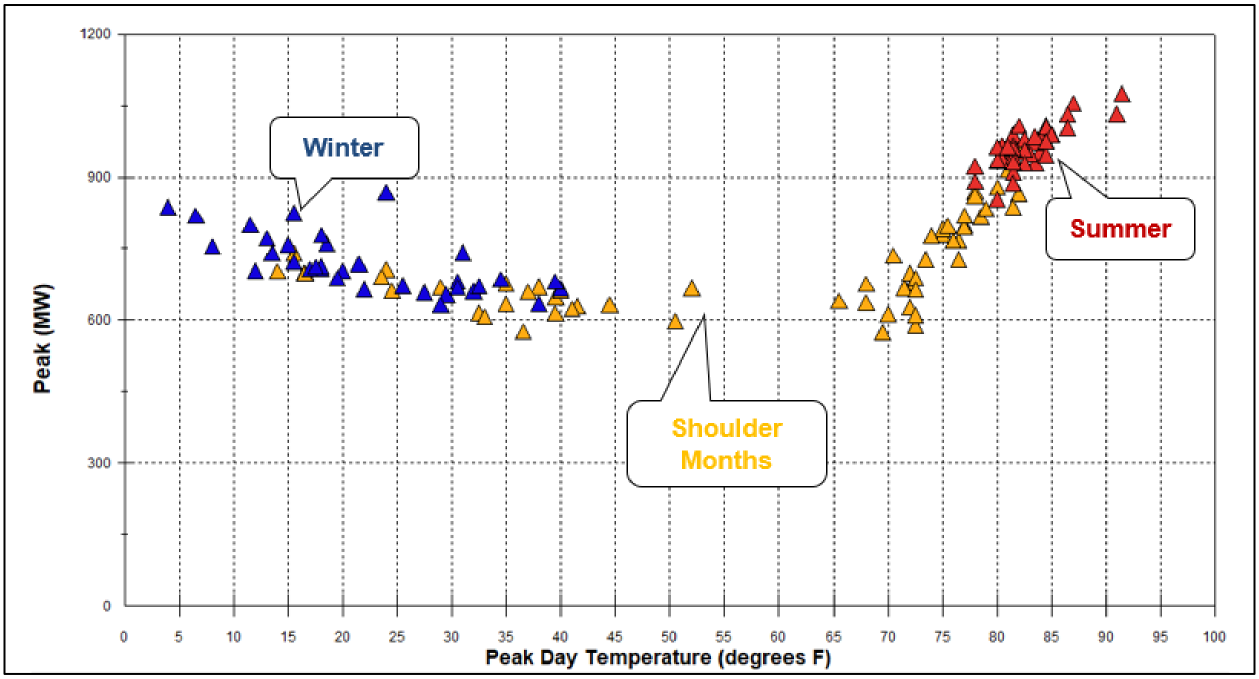
FIGURE 26: COOLING DEGREE DAYS



Peak-Day Weather Variables

Peak-day CDD and HDD are used in forecasting system peak demand. Peak-day HDD and CDD are derived by finding the daily HDD and CDD that occurred on the peak day in each month. The appropriate breakpoints for defining peak-day HDD and CDD are determined by evaluating the relationship between monthly peak and the peak-day average temperature, as shown in Figure 27.

FIGURE 27: MONTHLY PEAK DEMAND /TEMPERATURE RELATIONSHIP



Peak-day cooling occurs when temperatures are above 65 degrees and peak-day heating occurs when temperatures are below 55 degrees.

Normal peak-day HDD and CDD are calculated using 20 years of historical weather data, based on a rank and average approach, these are not trended. The underlying rate class sales models incorporate trended normal weather; derived heating and cooling sales from these models are an input into the peak model. Using a trended peak weather would double count the impact of increasing temperatures. Normal peak-day HDD and CDD are based on the hottest and coldest days that occurred in each month over the historical time period. Figure 28 shows the normal peak-day HDD and CDD values used in the forecast.