ELL IRP Data Filing

ENTERGY LOUISIANA: INTEGRATED SUPPLY PLAN

November 22, 2021

Entergy | WE POWER LIFE℠

Creating sustainable value for all

Purpose

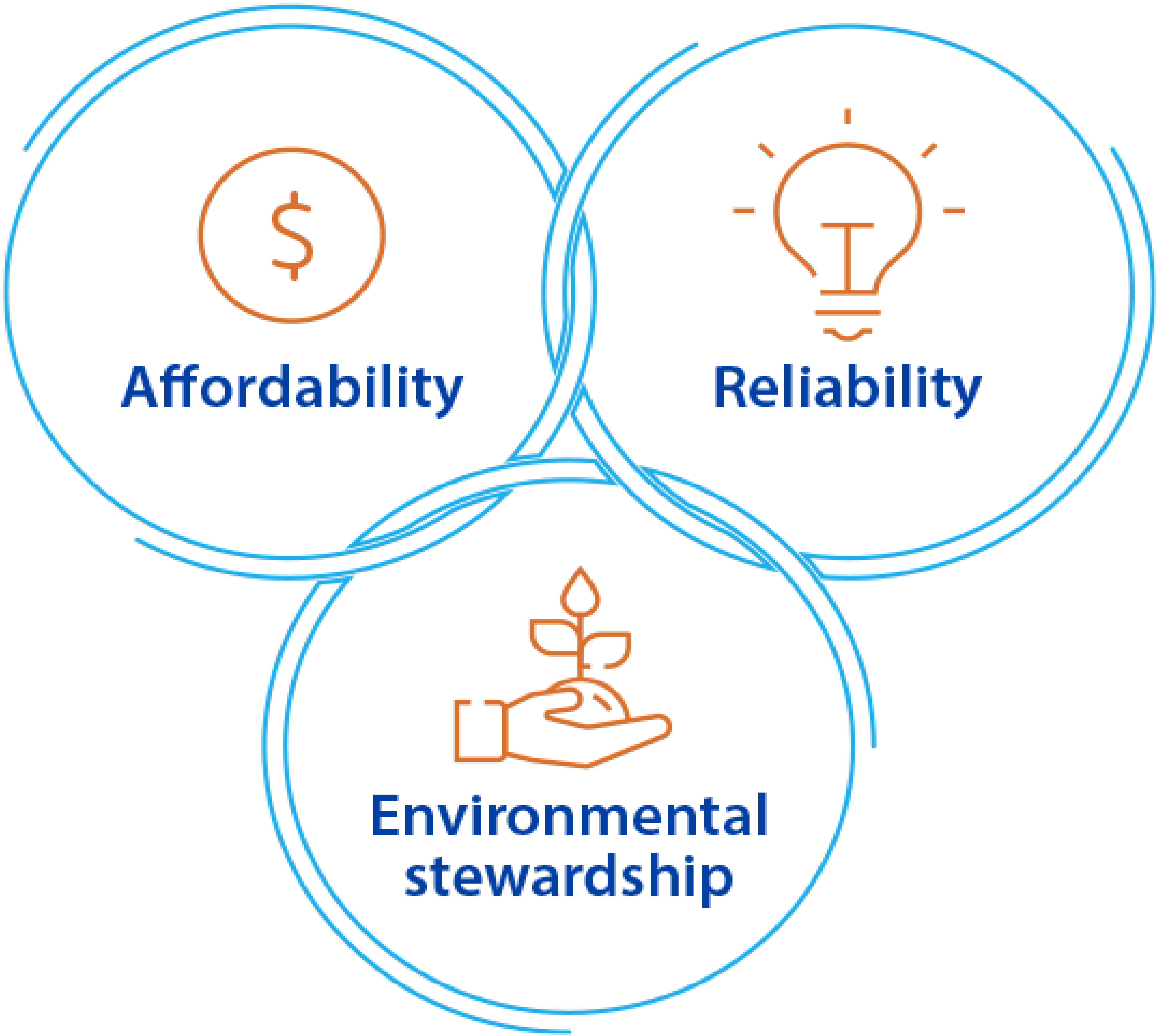
The purpose of this presentation is to provide an overview of the scope and assumptions of ELL's upcoming Integrated Resource Plan (IRP) with an expected filing of the Final IRP Report in May 2023

Contents

- Long-Term Planning Objectives and Principles
- Assessment of Resource Need
- Analytical Framework
- Supply Alternatives
- Assumptions
- Timeline

Key Objectives

- Sustainable portfolios are built with **<u>lowest reasonable</u> cost resources** and require balancing risks around three key planning objectives: affordability, reliability, and environmental stewardship.
- This balance looks at both the near-term and long-term benefits and risks associated with each key objective.



Planning Principles

1 We maintain and build upon our strong foundation of infrastructure

2 We continue to transform our resource portfolio with more sustainable resources

3 We leverage our unique position to deliver positive customer outcomes

- Maintain our nuclear fleet with safety and operational excellence
- Sustain existing gas to maintain system reliability
- Leverage strong wires backbone for the grid

- Exit coal by 2030
- Use new technologies (non-traditional) to match energy needs and capacity requirements
- Planning default is renewable first for new builds
- Utilize hydrogen capable large-scale gas where needed

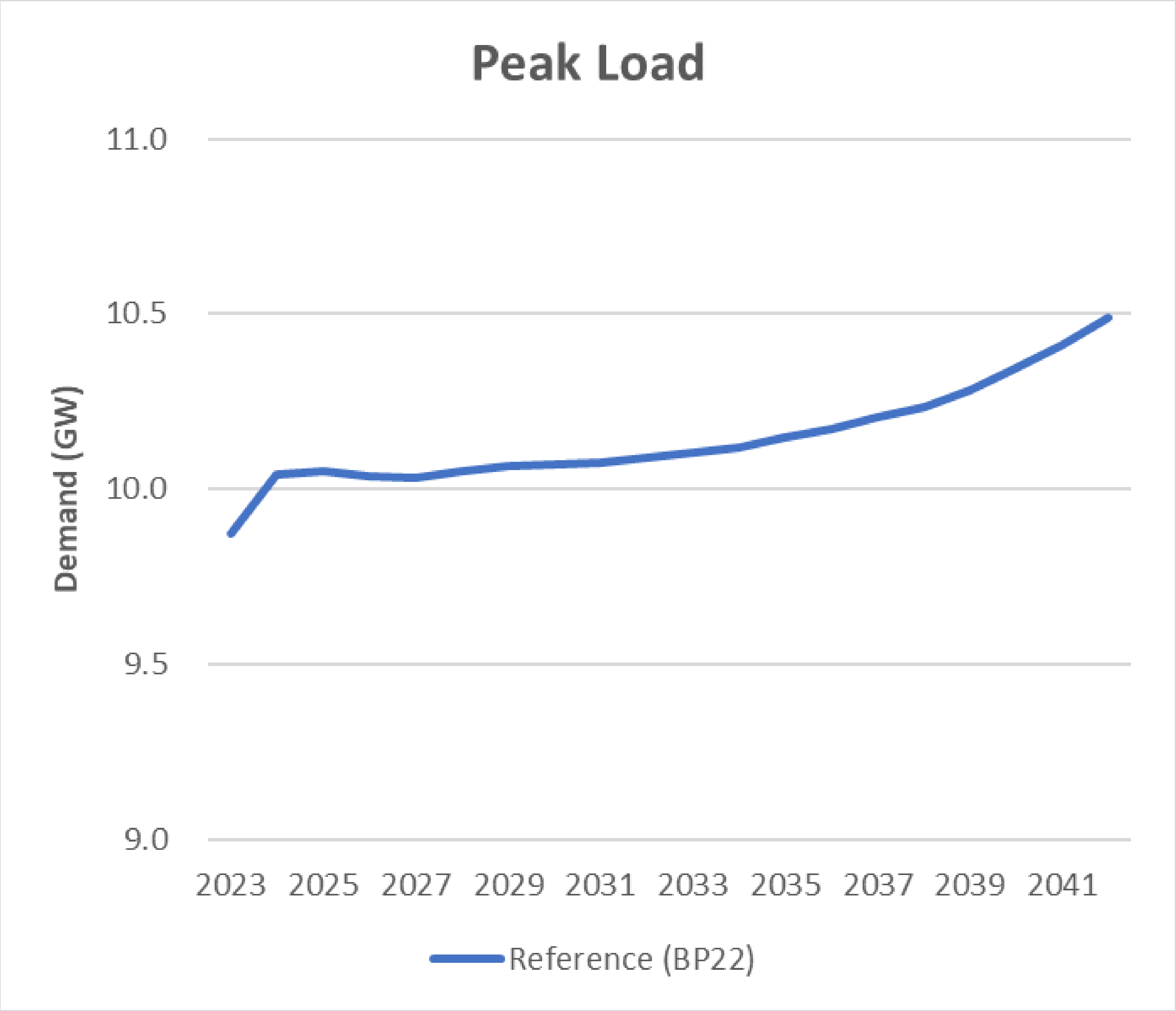
- Leverage unique service area advantages with technology, like Hydrogen
- Execute on customer partnerships and product & services

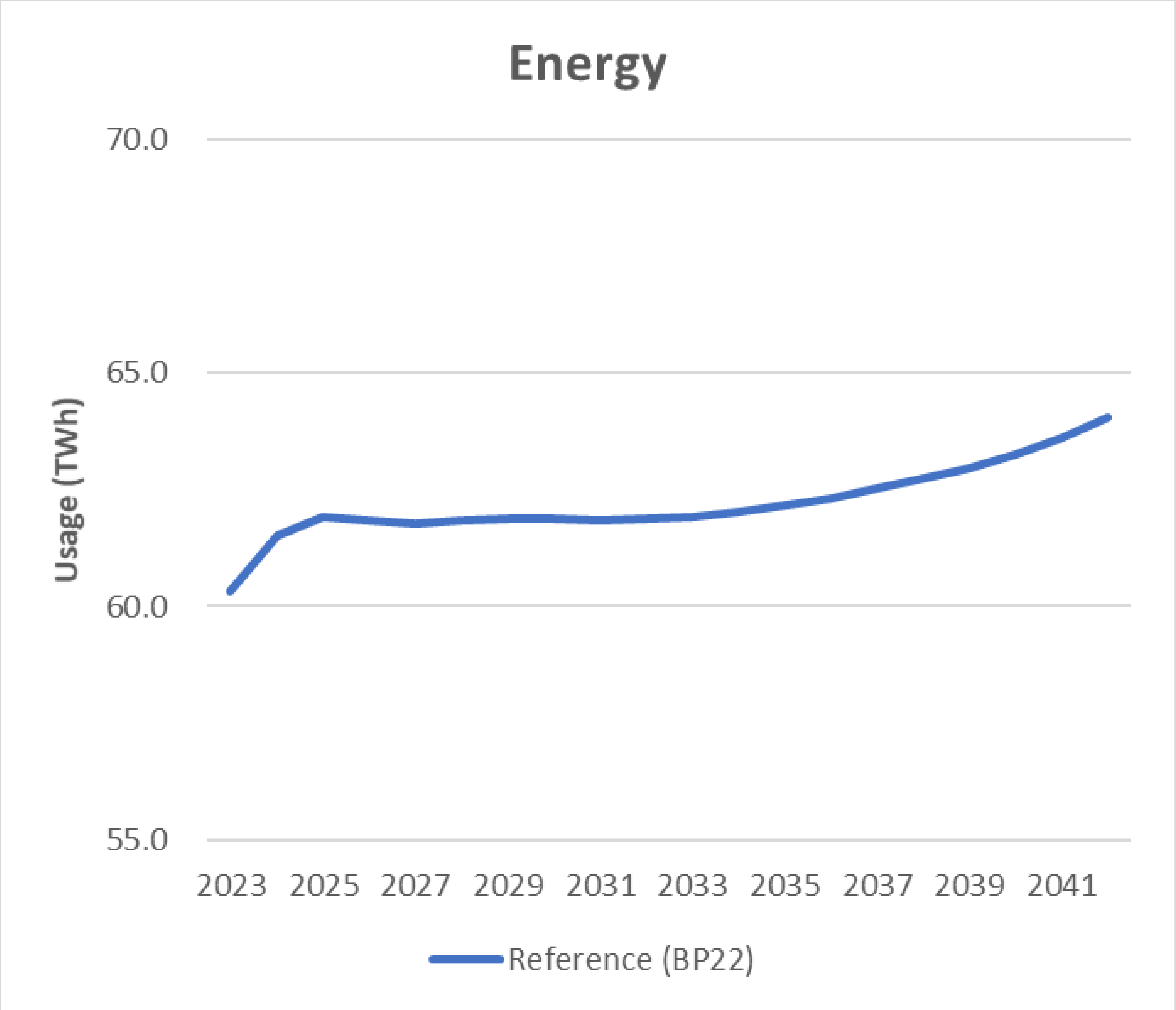
IRP Objective

- An Integrated Resource Plan (IRP) is a planning process and framework in which the costs and benefits of supply-side and demand-side alternatives are evaluated to develop resource portfolio options that help meet ELL's planning objectives
- Through the IRP process, ELL will conduct an extensive study of customers' needs over the next 20 years based on current available data
  - Evaluate impact of different fuels and technologies
  - Analyze resource portfolios under a variety of economic scenarios
  - Results of the IRP are not intended as static plans or pre-determined schedules for resource additions

Assessment of Resource Need

ELL Reference Case Load Forecast (BP22)



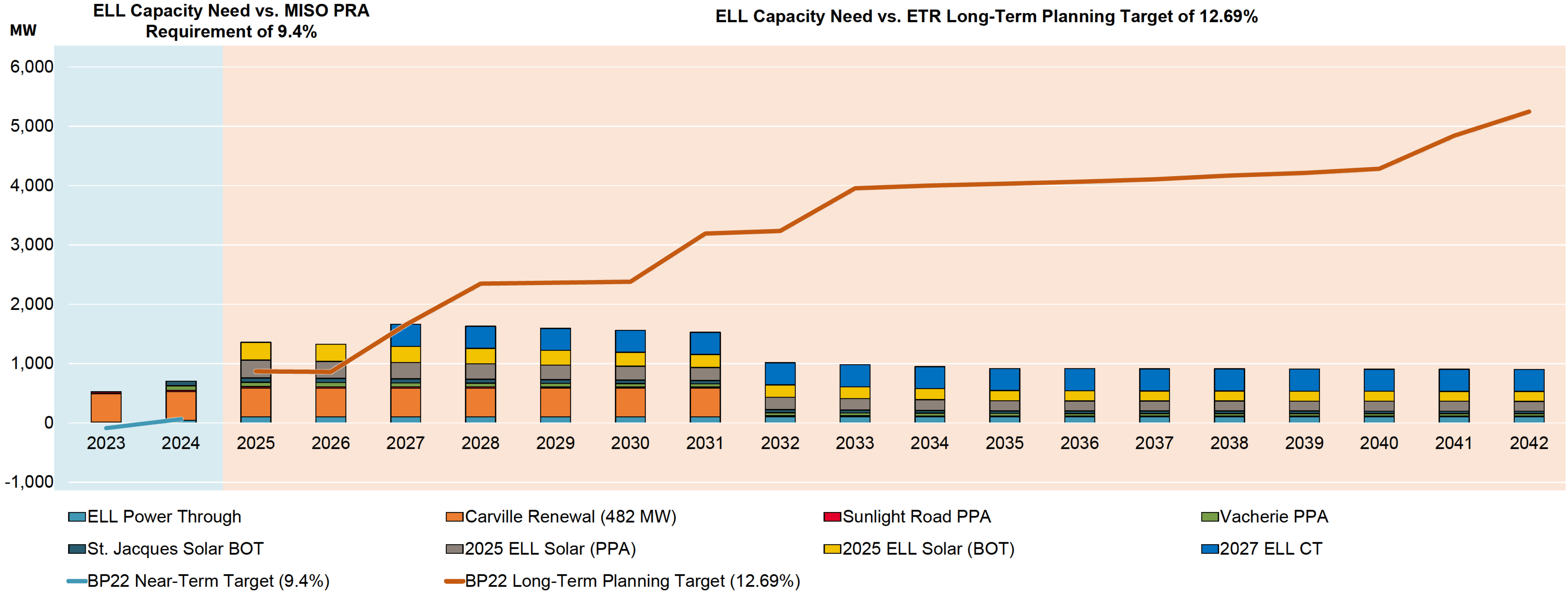


10-Yr CAGR	BP22
Peak (MW)	0.2%
Energy (GWh)	0.3%

Reference Forecast	2023	2028	2033	2038
Peak (MW)	9,874	10,050	10,103	10,235
Energy (GWh)	60,331	61,856	61,927	62,732

All values include Transmission and Distribution losses

ELL 20- Year Resource Need



	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Surplus	610	638	490	465	8	(720)	(769)	(818)	(1,663)	(2,222)	(2,973)	(3,052)	(3,115)	(3,151)	(3,193)	(3,259)	(3,304)	(3,378)	(3,937)	(4,676)

Notes:
- Solar resources assume capacity credit that aligns with the MTEP21 capacity credit assumption.

Capability Needs Reference Case Assumptions

UCAP Planning Assessment

ELL BP22

Start of Planning Year	6/1/2023	6/1/2024	6/1/2025	6/1/2026	6/1/2027	6/1/2028	6/1/2029	6/1/2030	6/1/2031	6/1/2032	6/1/2033	6/1/2034	6/1/2035	6/1/2036	6/1/2037	6/1/2038	6/1/2039	6/1/2040	6/1/2041	6/1/2042
End of Planning Year	5/31/2024	5/31/2025	5/31/2026	5/31/2027	5/31/2028	5/31/2029	5/31/2030	5/31/2031	5/31/2032	5/31/2033	5/31/2034	5/31/2035	5/31/2036	5/31/2037	5/31/2038	5/31/2039	5/31/2040	5/31/2041	5/31/2042	5/31/2043
ELL BP22 Reference Load																				
MISO Coincident Peak	9,424	9,575	9,584	9,574	9,571	9,590	9,602	9,609	9,618	9,632	9,650	9,671	9,698	9,727	9,761	9,796	9,834	9,884	9,952	10,030
Transmission Losses (1.80%)	170	172	173	172	172	173	173	173	173	173	174	174	175	175	176	176	177	178	179	181
Adjusted Load	9,594	9,748	9,757	9,747	9,743	9,763	9,775	9,782	9,791	9,805	9,824	9,845	9,872	9,902	9,937	9,972	10,011	10,062	10,131	10,211
Reserve Margin	900	914	1,238	1,237	1,236	1,239	1,240	1,241	1,243	1,244	1,247	1,249	1,253	1,257	1,261	1,265	1,270	1,277	1,286	1,296
Total Load Requirement	**10,494**	**10,662**	**10,995**	**10,984**	**10,980**	**11,002**	**11,016**	**11,024**	**11,034**	**11,050**	**11,070**	**11,094**	**11,125**	**11,158**	**11,198**	**11,238**	**11,281**	**11,338**	**11,416**	**11,507**
ELL Resources (UCAP)																				
Owned Resources + Affliate PPAs	**9,625**	**9,643**	**9,162**	**9,162**	**8,364**	**8,164**	**8,164**	**8,157**	**7,489**	**7,489**	**6,800**	**6,779**	**6,779**	**6,779**	**6,779**	**6,754**	**6,754**	**6,754**	**6,276**	**5,959**
Third Party PPAs	**664**	**664**	**664**	**663**	**661**	**189**	**188**	**187**	**53**	**25**	**16**	**15**	**14**	**14**	**14**	**14**	**14**	**-**	**-**	**-**
LMRs	**294**	**292**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**
Planned Resources	**521**	**701**	**1,358**	**1,324**	**1,662**	**1,628**	**1,594**	**1,561**	**1,528**	**1,013**	**980**	**948**	**916**	**914**	**912**	**910**	**908**	**905**	**903**	**901**
Total Existing Capacity	10,582	10,599	10,126	10,125	9,326	8,654	8,653	8,645	7,843	7,815	7,117	7,095	7,093	7,093	7,093	7,069	7,069	7,055	6,576	6,260
Total Planned + Existing Capacity	11,104	11,300	11,484	11,449	10,988	10,282	10,247	10,206	9,371	8,828	8,098	8,043	8,010	8,008	8,005	7,979	7,977	7,961	7,480	7,161
Existing Surplus/(Deficit)	89	(63)	(869)	(859)	(1,653)	(2,348)	(2,363)	(2,379)	(3,191)	(3,234)	(3,953)	(4,000)	(4,032)	(4,065)	(4,105)	(4,169)	(4,212)	(4,283)	(4,840)	(5,247)
Planned+Existing Surplus/(Deficit)	610	638	490	465	8	(720)	(769)	(818)	(1,663)	(2,222)	(2,973)	(3,052)	(3,115)	(3,151)	(3,193)	(3,259)	(3,304)	(3,378)	(3,937)	(4,346)

Entergy Louisiana's Owned or Contracted Capacity

- MW Values represent owned or contracted capacity available to meet ELL's forecasted peak load and reserve margin as of formulation of the set of assumptions used for the IRP analysis (GVTC as of 5/31/2021)

Unit	ELL Ownership Share [MW]	Resource Type	Unit [cont.]	ELL Ownership Share [MW, cont.]	Resource Type [cont.]
Acadia	526	Owned Resource/ Affiliate PPA*	Roy Nelson 6	211	Owned Resource/ Affiliate PPA*
ANO 1*	22		SCPS	912	
ANO 2*	26		Sterlington 7 A	46	
Big Cajun 2 Unit 3	135		Union 3	505	
Calcasieu 1	142		Union 4	505	
Calcasieu 2	159		Waterford 2	415	
Grand Gulf*	203		Waterford 3	1155	
Independence 1*	7		Waterford 4	32	
JWLPS	913		White Bluff 1*	13	
Little Gypsy 2	405		White Bluff 2*	12	
Little Gypsy 3	504		WPEC	370	
Ninemile 4	724		Agrilectric	9	Third Party PPA
Ninemile 5	728		Carville	243	
Ninemile 6	438		Capital Region Solar	50	
Ouachita 3	241		Oxy-Taft	471	
Perryville 1	355		Rain CII	28	
Perryville 2	101		Toledo Bend	48	
Riverbend 30	191		Vidalia	133	
Riverbend 70	389		Load Modifying Resources[1]	279	LMRs

Notes:

1. ELL's existing interruptible load contracts included in the "Load Modifying Resources" assumed to remain in place throughout entire study period

Deactivation and Contract Expiration Assumptions

- These deactivation assumptions do not constitute a definitive deactivation schedule but are based upon the best available information and are used as planning tools to help to prompt cross-functional reviews and recommendations
- As resources age and assumed deactivation dates near, as equipment failures occur, or as operating performance diminishes, cross-functional teams are then assembled to evaluate whether to keep a particular unit in service for a specified amount of time and level of reliability.
- Any resulting deviations from the generic assumptions are detailed below.
- Consistent with its 2019 IRP Action Plan, ELL has completed an analysis that contemplates the cessation of the use of coal at Roy Nelson 6. Resultantly, Nelson 6 is assumed to deactivate prior to 2030

[redacted]

- ELL's 2019 IRP included a generic deactivation assumption of 30 years for CTs and CCGTs. Since that time, ELL conducted a detailed analysis on the expected remaining useful life of those resources. The result of that analysis concludes that ELL's CTs and CCGTs are assumed to have a remaining useful life of longer than 30 years and most are assumed to operate beyond the end of the 2023 IRP study period (2042).

Near Term (10 Year) Deactivations	Unit	Deactivation Assumption
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
White Bluff	1,2	2028
Independence	1	2030
Ninemile	4	2031

Near Term (10 Year) Contract Expirations	MW	Fuel	Deactivation Assumption
Montauk	2	Biomass	2024
Toledo Bend	48	Hydro	2023
Oxy-Taft	471	Natural Gas	2028

Analytical Framework

Futures

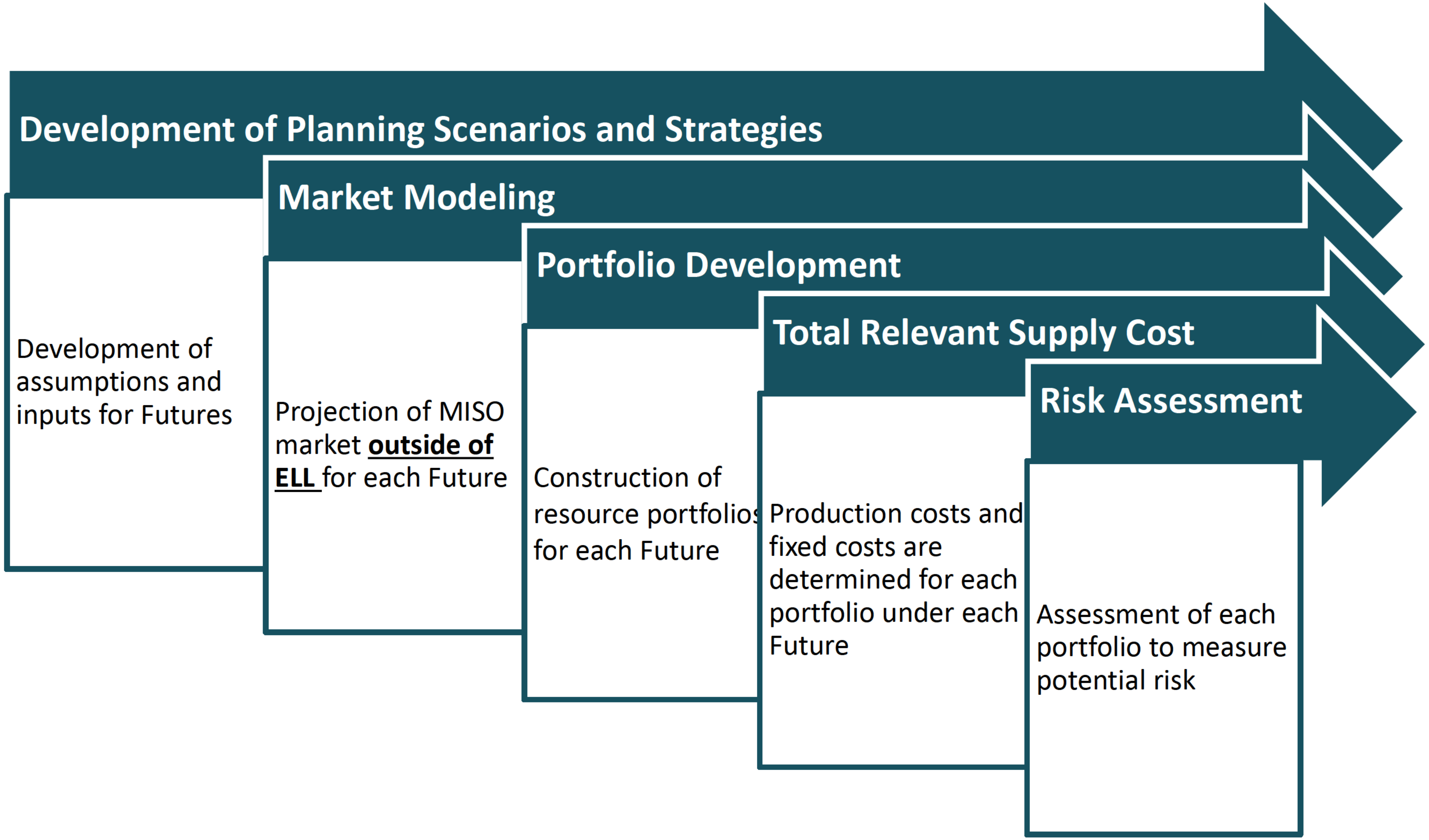
- The IRP analysis will rely on 3 futures to assess supply portfolios across a range of market outcomes
- The future approach, along with sensitivities, will allow ELL to assess portfolio performance as it is related to expected total supply cost and risk

	Future 1	Future 2	Future 3
Peak Load & Energy Growth	• BP22	• TBD[2]	• TBD[2]
Natural Gas Prices	• Reference	• High	• Low
MISO Coal Deactivations[1]	• All ETR coal by 2030 • All MISO coal aligns with MTEP Future 1 (46 year life)	• All ETR coal by 2030 • All MISO coal aligns with MTEP Future 3 (30 year life)	• All ETR coal by 2030 • All MISO coal aligns with MTEP Future 2 (36 year life)
MISO legacy gas deactivations	• 55 year life	• 45 year life	• 50 year life
Carbon tax scenario ICF 2020 post-election	• ICF Point of View	• ICF Legislative Case (High)	• ICF 50% Reduction Case (Mid)
ITC/PTC Assumptions	• Current methodology	• HR 5376	• Current Methodology
DSM Potential Study	• Moderate	• High (ICF)	• Reference (ICF)
Allow Future Emitting Resource	• Yes	• No	• Yes
Narrative	• Aligns with Point of View CO2 price consistent with expected probability weighted CO2 price. • Point of View CO2 leads to electrification decisions driven by sustainability efforts rather than CO2 prices. • Point of View CO2 leads to relatively constant consumption of natural Gas and constant pricing. • Coal is not economic to operate past 46 years of life and Legacy Gas is not economic to operate to full life assumption.	• Aligns with high CO2 price consistent with aggressive decarbonization mandate scenarios. • High CO2 price increases natural gas extraction and export leading to high gas prices. • Coal is not economic to operate past 30 years of life and Legacy Gas is not economic to operate to full life assumption.	• Aligns with mid CO2 price representative consistent with ICF 50% Reduction Case • Mid price CO2 lowers consumption of Natural Gas thus decreasing prices on a global scale. • Coal is not economic to operate past 36 years of life and Legacy Gas is not economic to operate to full life assumption

Notes:

1. Deactivation assumptions will be consistent with current planning assumptions for ELL owned or contracted generation
2. Peak Load and Energy Growth for Future 2 and Future 3 will be provided in a supplemental filing as they require information from the ongoing DER/DSM Potential Study

Analytic Process to Create and Value Portfolios



Assessment of Portfolio Performance Across Scenarios

- Optimized portfolios will be generated for each future (i.e. to each future's load, market prices, gas prices, etc.) using Aurora capacity expansion module
- Each portfolio will be tested in each future using Aurora production cost modeling software
- The total supply cost of each of the future/portfolio combinations represents the present value of fixed and variable costs to customers

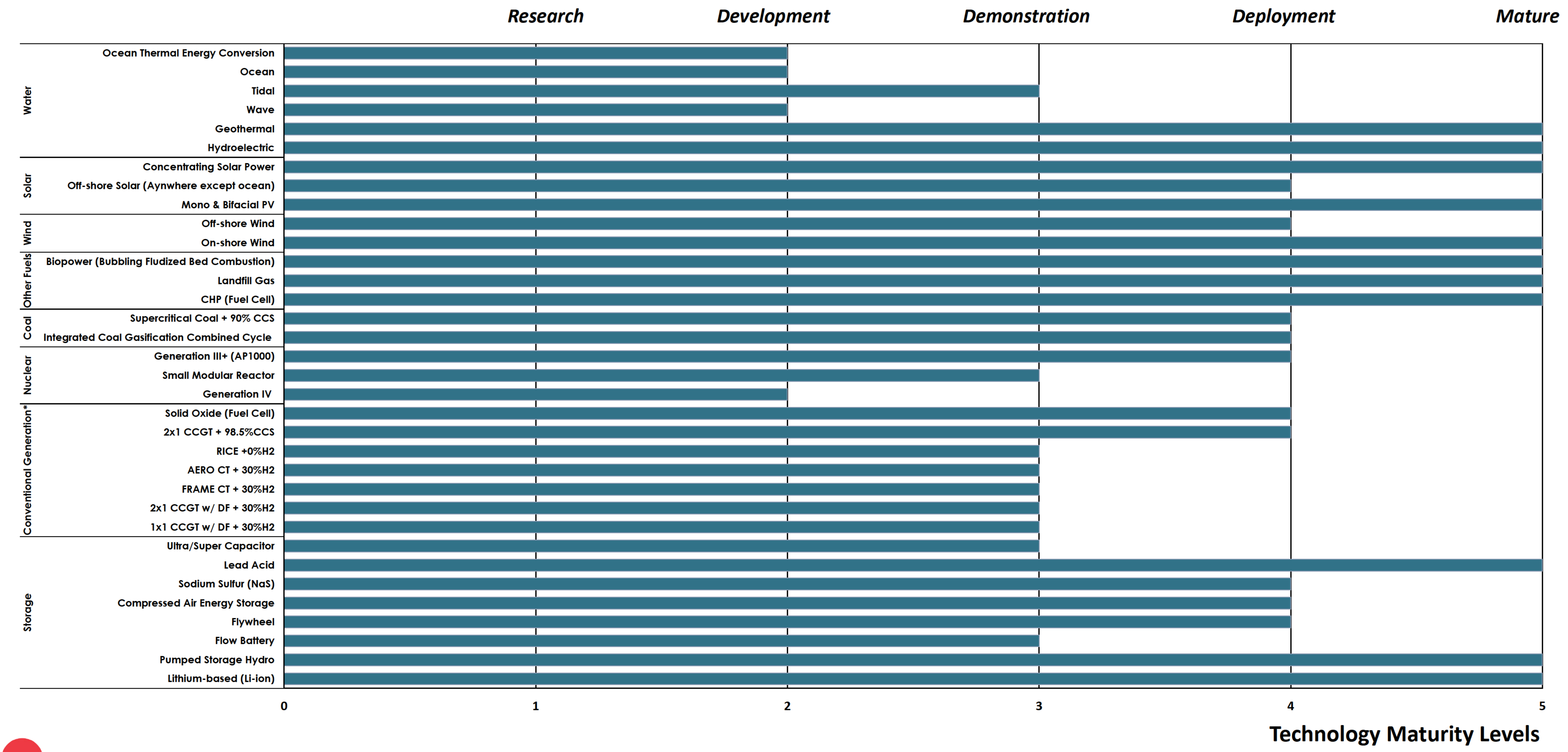
ILLUSTRATIVE ONLY—Actual number of Scenario/Portfolio combinations is TBD

Portfolios / Future	Opt Portfolio 1	Opt Portfolio 2	Opt Portfolio 3
Future 1	R_{11}	R_{12}	R_{13}
Future 2	R_{21}	R_{22}	R_{23}
Future 3	R_{31}	R_{32}	R_{33}

Note: "R" = resulting total relevant supply cost
Subscript is in reference to the corresponding future and portfolio

Supply Alternatives

Technology Maturity of Supply Side Resources



Gas + Hydrogen Resource Assumptions

Technology[1]			Summer Capacity [MW]	Capital Cost [Nominal, 2022$/kW] [2]	Fixed O&M [Levelized R., 2022$/kW-yr]	Variable O&M [Levelized R., 2022$/MWh]	Heat Rate [Btu/kWh]	Equivalent Forced Outage Rate [%]	Planned Maintenance Rate [%]
Unit	*Configuration*	*H2 Capability*							
CT	**M501JAC**	**30%**	365	$900	$6.66	$14.74	9,165	2.00%	4.50%
CCGT	**1x1_M501JAC_w/o Duct Firing**	**30%**	525	$1,130[3]	$18.43	$3.47	6,375	2.50%	5.50%
CCGT	**1x1_JAC Ultra-Flex_Fast Start[4]**	**30%**	578	$1,320	$18.43	$3.47	6,422	TBD	TBD
CCGT	**1x1_GAC Ultra-Flex_Fast Start[5]**	**30%**	413	$1,120	$18.43	$3.47	6,841	TBD	TBD
CCGT	**2x1_M501JAC_w/o Duct Firing**	**30%**	1,055	$900	$12.07	$3.48	6,355	2.50%	5.50%
Aero-CT	**LMS100PA**	**30%**	100	$1,490[6]	$6.47	$3.21	9,015	0.80%	2.90%
RICE	**7x_Wartsila_18V50SG**	**0%[7]**	129	$1,750	$23.35	$8.06	8,464	1.00%	4.00%

Notes:

1. Performance is at summer conditions (97°F, 56%RH, 14.696 psia) and assumes evaporative inlet air cooling where applicable.
2. Capital costs assume hydrogen burning capability, except for RICE units (see note 5).
3. Capital cost assumes that an SCR will be used for NOx emission control.
4. Preliminary cost estimates and data, outage and maintenance rates are TBD
5. Preliminary cost estimates and data, outage and maintenance rates are TBD
6. At this time, costs to enable hydrogen capability not included
7. As of date, hydrogen capability is planned but not yet demonstrated, and therefore, costs or performance impacts of hydrogen firing capability is excluded.

Solar Resource Assumptions

Installed Cost Projections[1]

Utility-scale Solar (Single Axis Tracking)	
Year	**Nominal ($/kW)**
2023	$1,063
2024	$1,031
2025	$991
2026	$957
2027	$938
2028	$930
2029	$926
2030	$923
2031	$923
2032	$925
2033	$928
2034	$930
2035	$935
2036	$940
2037	$947
2038	$954
2039	$960
2040	$967
2041	$977
2042	$987

Other Modeling Assumptions

	Solar
Size (MW)	100MW
Fixed O&M (Levelized R. 2022$/KWac-yr)[2]	$10.52
Useful Life (yr)	30
MACRS Depreciation (yr)	5
Capacity Factor[3]	25.6%
DC:AC	1.3
Hourly Profile Modeling Software	PlantPredict

ITC Assumptions

	ITC
2022	26%
2023	22%
2024[4]	10%

- The federal Investment Tax Credit (ITC) reduces the solar capital cost input to Aurora[5]
- The value of the ITC is calculated as the product of the applicable percentage in the table above and an estimate of the ITC-eligible portion of the total forecasted capital cost of solar.[6]

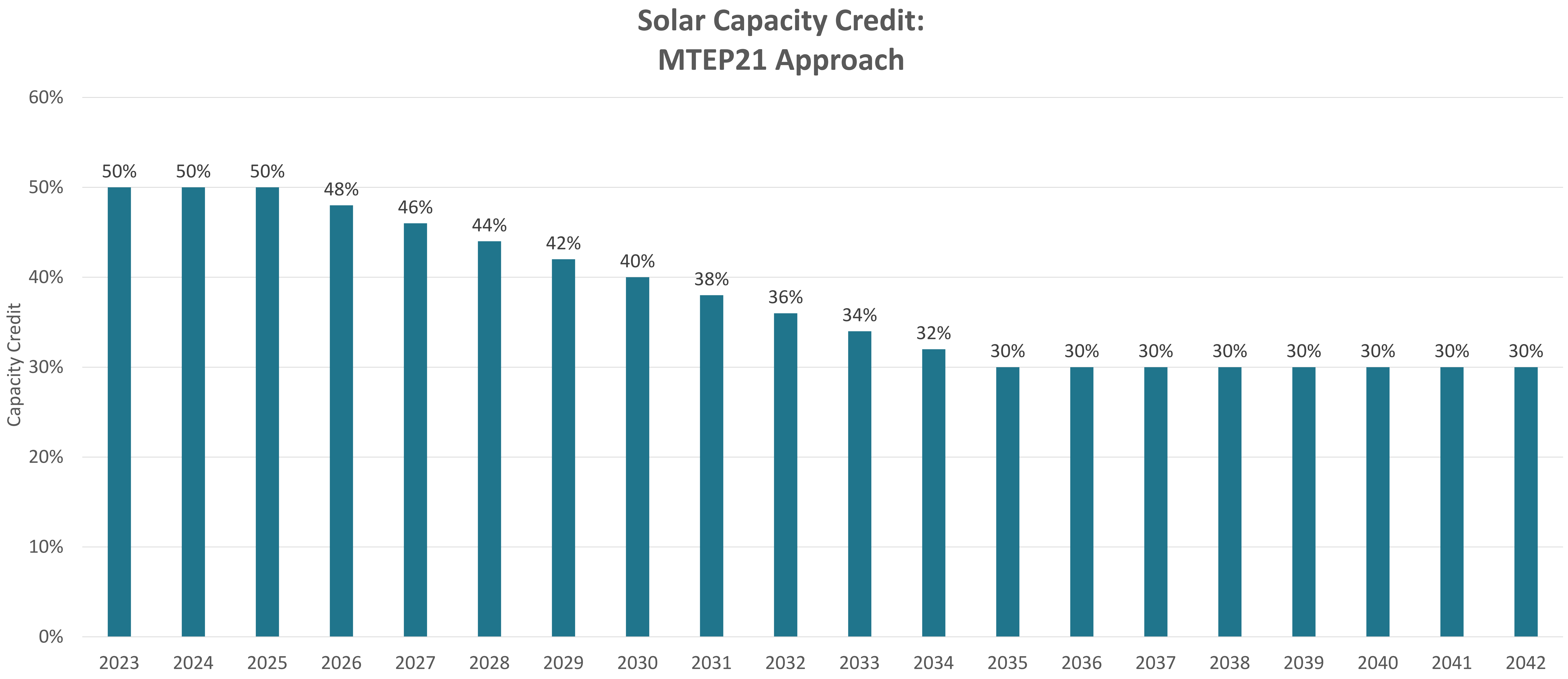
Notes:

1. *Installed capital costs in table above will be increased by $100/kW in the ELL IRP models to account for the transmission interconnection costs for new solar resources.*
2. *Solar and Wind Fixed O&M excludes property tax and insurance; Solar includes inverter replacement in year 16.*
3. *Capacity Factor based on MISO South (Solar & Wind) and Gulf of Mexico (Off-shore Wind, Fixed) region.*
4. *ITC assumed 10% in 2024 and thereafter.*
5. *ITC Benefit normalized over asset useful life.*
6. *ITC –eligible portion assumed to be 90% of total capital cost.*

Source:

Proposed Cumulative Solar Capacity Credit Assumption

- EPG proposes for the cumulative solar capacity credit assumption to align with MISO's MTEP21 Futures April 2021 report:
  - All solar units will assume 50% capacity credit every year until 2025 and decrease 2% each year thereafter until a minimum capacity credit of 30% is reached.



Wind Assumptions

Installed Cost Projections

On-shore Wind		Off-shore Wind, Fixed	
	Nominal ($/kW)		Nominal ($/kW)
2023	$1,505	**2023**	$4,189
2024	$1,503	**2024**	$4,130
2025	$1,510	**2025**	$4,077
2026	$1,526	**2026**	$4,028
2027	$1,545	**2027**	$3,983
2028	$1,566	**2028**	$3,943
2029	$1,587	**2029**	$3,906
2030	$1,608	**2030**	$3,872
2031	$1,629	**2031**	$3,841
2032	$1,652	**2032**	$3,813
2033	$1,676	**2033**	$3,787
2034	$1,700	**2034**	$3,764
2035	$1,725	**2035**	$3,742
2036	$1,749	**2036**	$3,722
2037	$1,774	**2037**	$3,703
2038	$1,801	**2038**	$3,685
2039	$1,828	**2039**	$3,668
2040	$1,855	**2040**	$3,651
2041	$1,883	**2041**	$3,635
2042	$1,913	**2042**	$3,618

Other Modeling Assumptions

	On-shore Wind	Off-shore Wind, Fixed
Size (MW)	200MW	600MW
Fixed O&M (Levelized R. 2022$/KWac-yr) 1	$37.72	$93.32
Useful Life (yr)	30	25
MACRS Depreciation (yr)	5	5
Capacity Factor [2]	36.8%	37.1%
Hourly Profile Modeling Software	NREL SAM	NREL SAM

Capacity Credit Modeling Assumptions

	On-shore Wind	Off-shore Wind, Fixed
MISO Wind Capacity Credit	16.3%	16.3%

Notes:

1. *Solar and Wind Fixed O&M excludes property tax and insurance; Solar includes inverter replacement in year 16.*
2. *Capacity Factor based on MISO South (Solar & Wind) and Gulf of Mexico (Off-shore Wind, Fixed) region.*

Source:

IHS 2019 (On-shore Wind):

ATB NREL 2020 (Off-shore Wind)

Renewable Resource Locational Assumptions

- Renewable new build alternatives for ELL's portfolio (e.g. solar, wind) are based on characteristics of resources located near ELL's service territory, and are located in MISO Local Resource Zone 9
- Non-ELL solar additions are modeled based on a generic assumption of solar performance for MISO South, and are added to MISO Central, MISO North, and MISO South
- Non-ELL wind additions are modeled based on a generic assumption of wind performance for the MISO North region and are added to MISO Central and MISO North

Battery Assumptions

Installed Cost Projections[1]

Battery Storage w/ Augmentation	
Year	**Nominal ($/kW)**
2023	$1,171
2024	$1,153
2025	$1,137
2026	$1,132
2027	$1,131
2028	$1,131
2029	$1,133
2030	$1,134
2031	$1,125
2032	$1,118
2033	$1,114
2034	$1,111
2035	$1,110
2036	$1,109
2037	$1,110
2038	$1,111
2039	$1,113
2040	$1,116
2041	$1,120
2042	$1,124

Other Modeling Assumptions

	Battery Storage
Energy Capacity : Power [2]	4:1
Size (MW/MWh)	50MW/200MWh
Fixed O&M (Levelized R. 2022$/KWac-yr) [3]	$13.39
Useful Life (yr)	20
MACRS Depreciation (yr)	7
Round-trip efficiency	86%
Hourly Profile Modeling Software	Aurora

Source:

Notes:

1. *BESS Installed Capital Cost includes 10% initial oversizing in year 1 to account for Depth of Discharge (DoD), followed by an additional 10% augmentation every five years (year 6, 11, & 16). This corresponds to a degradation rate of 2% of BESS capacity per year.*
2. *Current MISO Tariff requirement for capacity credit*
3. *Battery Fixed O&M excludes property tax and insurance cost; includes recycling cost of $1.00 (2021$) in year 20.*

DER and DSM Potential Study

- ICF has been retained by ELL to perform a Demand Side Management (DSM) and Distributed Energy Resource (DER) potential study
- The study considered scenarios to create savings forecasts for DSM programs and DERs:
  - DER study:
    1. Reference case
    2. High case
  - Energy Efficiency (EE) study:
    1. Reference Case (based on existing ELL programs)
    2. High Case (existing programs plus new best practice programs)
  - Demand Response (DR) study:
    1. Reference case
    2. High case
- Hourly loadshapes and program costs associated with these savings forecasts will serve as inputs to IRP capacity expansion and production cost modeling in Aurora.
- DSM programs that appear to be cost-effective from the Potential Study will be considered in ELL's portfolio evaluations to meet supply needs.

Miscellaneous Assumptions

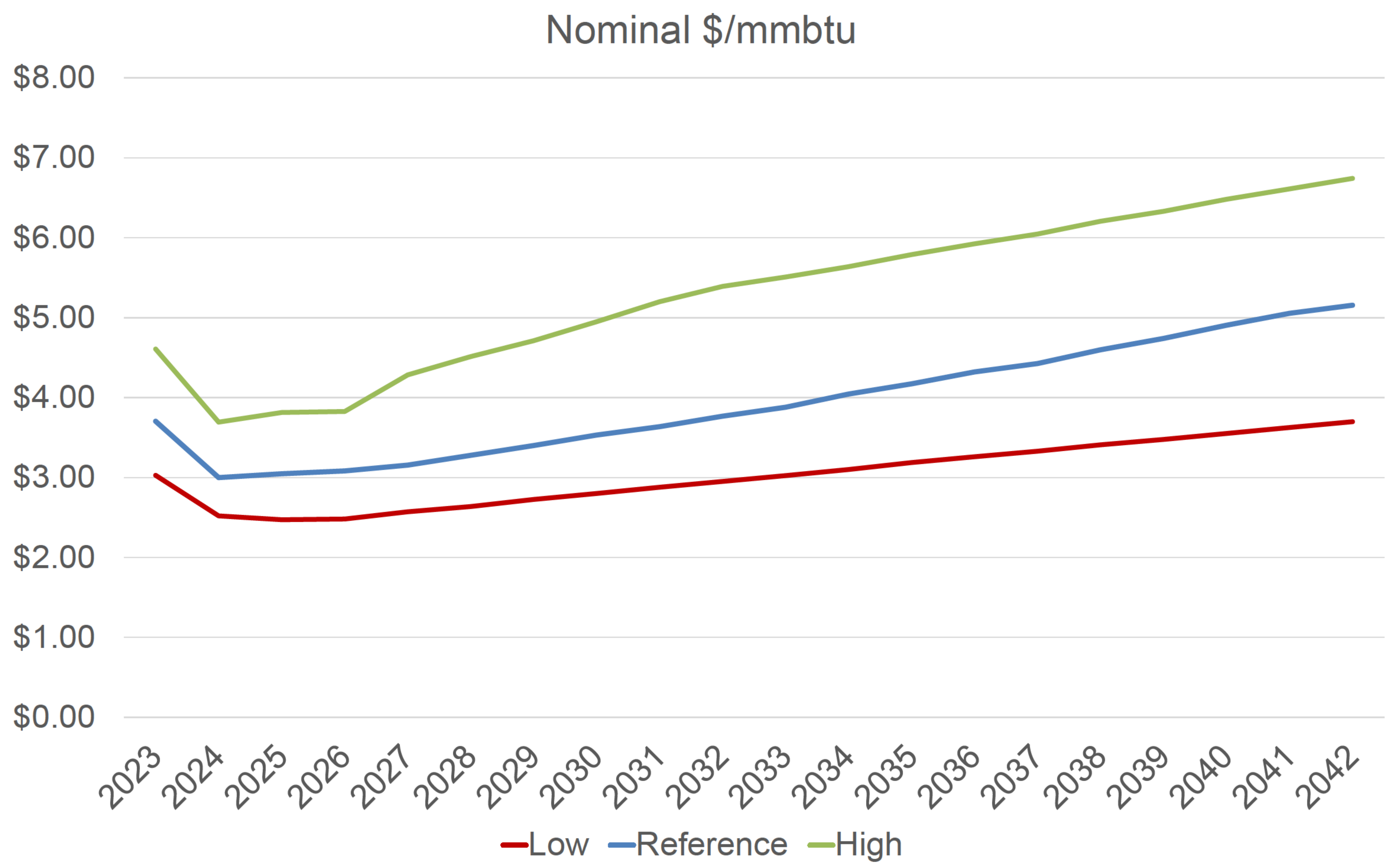
- IRP cost inputs reflect:
  - A generic property tax and insurance assumption of 1.5%
  - A general inflation rate of 2.0%

- QFs from which ELL is no longer required to purchase QF put or have otherwise elected to participate in the MISO market are assumed to operate as Market Participants ("MPs") that schedule and sell their energy into the MISO market like other market generators. QFs that put energy to ELL at ELL's avoided cost rate are modeled as Behind the Meter Generators that generate energy on an assumed fixed schedule based on historical put amounts.

- Because only the MISO region is modeled, there are no hurdle rates or wheeling charges used for trade between MISO and other regions. Similarly, no hurdle rates are assumed for trade within MISO.

Modeling Assumptions

Gas Price Forecast



Forecasting Methodology

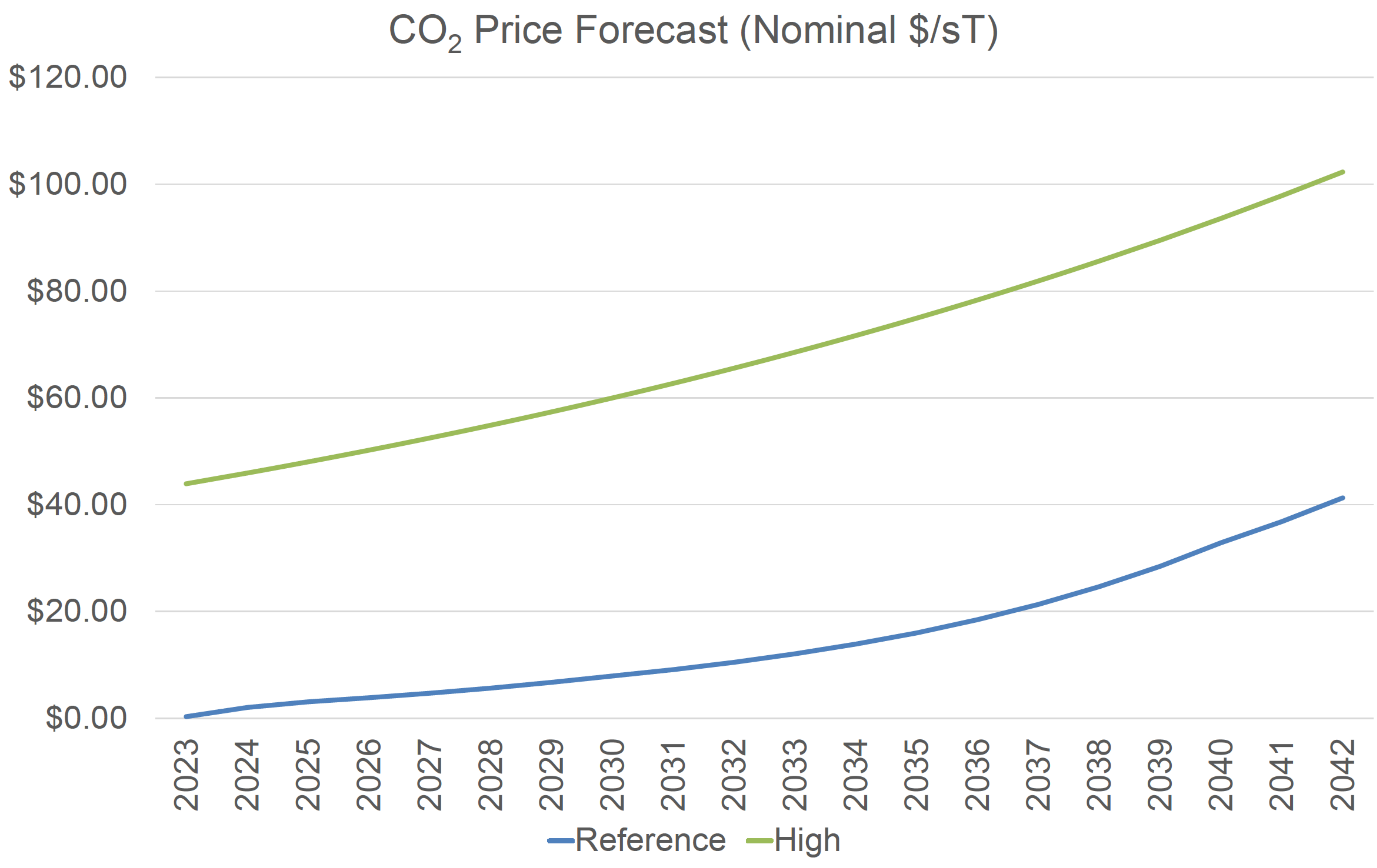
Reference case

- NYMEX forwards (30-day average as of 11/4/2021) used for the first year: 2022
- Linear interpolation for year two: 2023
- Average of consultant fundamentals-based forecasts between year three through year twenty: 2024-2041
- Followed by constant real dollars

High/Low case

- Methodologies are identical to the reference case, except implied volatilities are utilized in the first year to create a distribution around NYMEX prices; the high and low cases are +/- 0.5 standard deviations from the mean in the first year

CO2 Price Forecast



Forecasting Methodology

- The **High CO2** scenario is based on the ICF POV Legislative Case, which is based on the Climate Leadership Council's Carbon Dividend proposal.
- The **Reference CO2** scenario is based on the four probability-weighted ICF POV cases: No CO2 Policy/Clean Energy, Regulatory, 50% Reduction, and Legislative.
    - The no CO2 or clean energy policy case represents either no carbon pricing program at the federal level or a program similar to the ACE rule.
    - The regulatory case reflects carbon prices representative of a rule similar to the CPP in stringency.
    - The 50% Reduction case targets a 50% percent national reduction from 2005 sector emissions by 2050.

Capacity Value Forecast

Capacity Value ($/kW-yr)		
[redacted]		
	ICAP	UCAP
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]
2041	[redacted]	[redacted]
2042	[redacted]	[redacted]

Inflation Forecast and Financial Assumptions

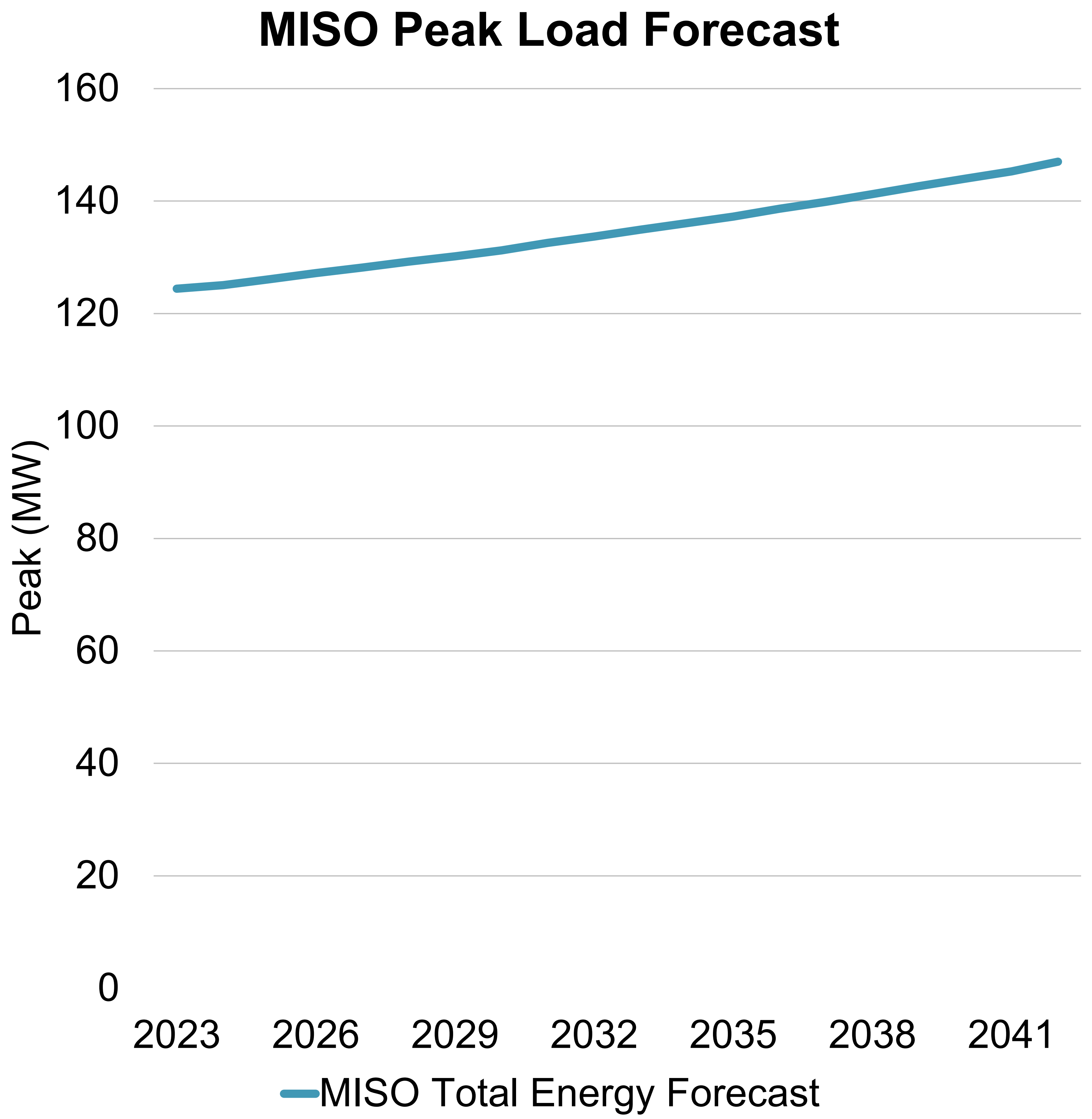
2021 EPG GDP POV	
	Inflation Rate
2023	2.25%
2024	2.00%
2025	2.00%
2026	2.00%
2027	2.00%
2028	2.00%
2029	2.00%
2030	2.00%
2031	2.00%
2032	2.00%
2033	2.00%
2034	2.00%
2035	2.00%
2036	2.00%
2037	2.00%
2038	2.00%
2039	2.00%
2040	2.00%
2041	2.00%
2042	2.00%

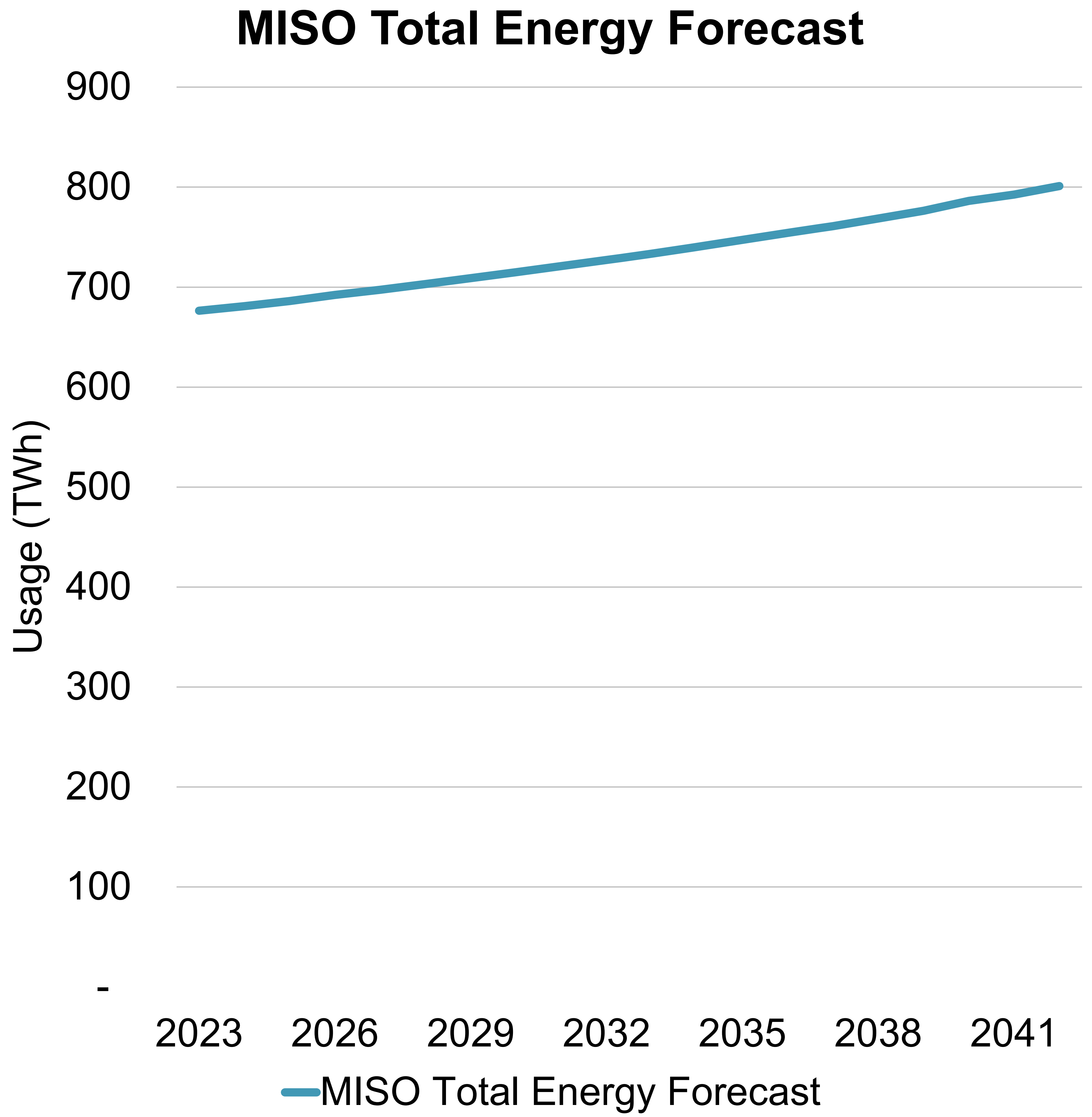
- ELL's WACC is used to assess present value for all potential resource additions to ELL's portfolio

	Capital Ratios	Capital Costs	Return on Rate Base	Weighted Average Cost of Capital
Debt	50.02%	3.99%	1.99%	1.47%
Preferred Stock	0.00%	0.00%	0.00%	0.00%
Common Equity	49.98%	9.50%	4.75%	4.75%

Tax Rate	26.08%

MISO Peak Load Forecast





Reference Forecast	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Peak (MW)	124	125	126	127	128	129	130	131	133	134	135	136	137	139	140	141	143	144	145	147
Energy (TWh)	676	681	686	692	697	703	709	715	721	727	733	740	747	754	761	769	776	786	793	801

Electric Vehicle Assumptions

- The ELL reference case load forecast (BP22) developed for the 2022 IRP includes an assumption around electric vehicle adoption whereby ~100% of new passenger vehicle sales in ELL's service territory will be EVs by 2055

- This level of adoption is aligned with many 3rd party EV adoption scenarios whereby 100% of new vehicles sales in the US will be electric between 2050 and 2060

- MWH attributed to electric vehicle charging in the reference case forecast is expected to add 0.5% to ELL's load by 2032, growing to 3.4% by 2042

- There are several factors that can affect the speed of adoption for EVs:
  - Government incentives
  - Battery prices
  - EV Range / Range Anxiety
  - Cost parity with ICE vehicles
  - # of options/offerings
  - Other cultural factors

- Electric vehicle adoption for the futures scenarios are TBD

ELL EV Demand Additions (GWh)	
2023	29.2
2024	38.6
2025	50.7
2026	66.0
2027	85.4
2028	110.1
2029	141.8
2030	183.0
2031	235.3
2032	300.9
2033	381.7
2034	481.3
2035	601.6
2036	745.5
2037	913.6
2038	1,109.7
2039	1,333.0
2040	1,584.7
2041	1,860.5
2042	2,163.6

Additional Items to be provided in a Supplemental Filing

The following items are still under development and will be provided in a supplemental filing when available. ELL intends to provide this no later than Q2 2022.

1. Resource Levelized Cost of Electricity Assumptions
2. Delivered Coal Price Forecast
3. NOx and SO2 Price Forecast
4. Future Load Forecast Peak and Energy for Futures 2&3
5. EV Assumptions for Futures 2&3
6. Solar Battery Hybrid Resource Assumptions
7. Technologies retained for Capacity Expansion
8. DSM and DER Potential Studies

Timeline

Timeline

Description	Target Date	Status
Filing initiating Second Full Cycle	October 22, 2021	✓
File Data Assumptions and description of studies to be performed	November 22, 2021	✓
First Stakeholder meeting	December 2021[1]	-
Stakeholder written comments due	February 22, 2022	-
Publish draft IRP reports	October 21, 2022	-
Second Stakeholder meeting	November 2022	-
Stakeholder comments on draft IRP reports due	January 23, 2023	-
Staff comments on draft IRP reports due	February 22, 2023	-
Final IRP reports due	May 22, 2023	-
Stakeholder list of disputed issues and alternative recommendations due	July 23, 2023	-
Staff recommendation to Commission on whether a proceeding is necessary to resolve issues	August 22, 2023	-
Commission order acknowledging IRPS or setting procedural schedule for disputed issues	October 23, 2023	-
Filing initiating 4th full cycle	October 22, 2025	-

Notes:

1. Stakeholder Meeting dates are approximate as the actual dates will be are determined following consultation with LPSC Staff and the parties

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