



4/24/2026

ELL 2027 IRP Supplemental Data Filing

Docket U-37764



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 2027

Contents

1. Long-Term Planning Objectives and Principles
2. Assessment of Resource Need
3. Analytical Framework
4. Supply Alternatives
5. Modeling Assumptions
6. Timeline

Changes in the Supplemental Filing

- Updated the Load Forecast slides to show all four futures
- Included the Energy Forecast for all four futures
- Added Sterlington Solar to the "ELL Owned or Contracted Capacity" slide
- Changed "Aero" to "Industrial" on the "Technology Readiness" and "Identified Supply-Side Resource Alternatives" Slides
- Added numbers for the graph to the Gas, Coal, NOx, and SO2 forecast slides.
- Specified the first year the Long Term Capacity Expansion process may select a resource and added the currently announced planned resources on the "ELL 20-Year Resource Need" slide.
- Clarified what load is included in the chart on the "MISO Peak Load Forecast" slide.

01

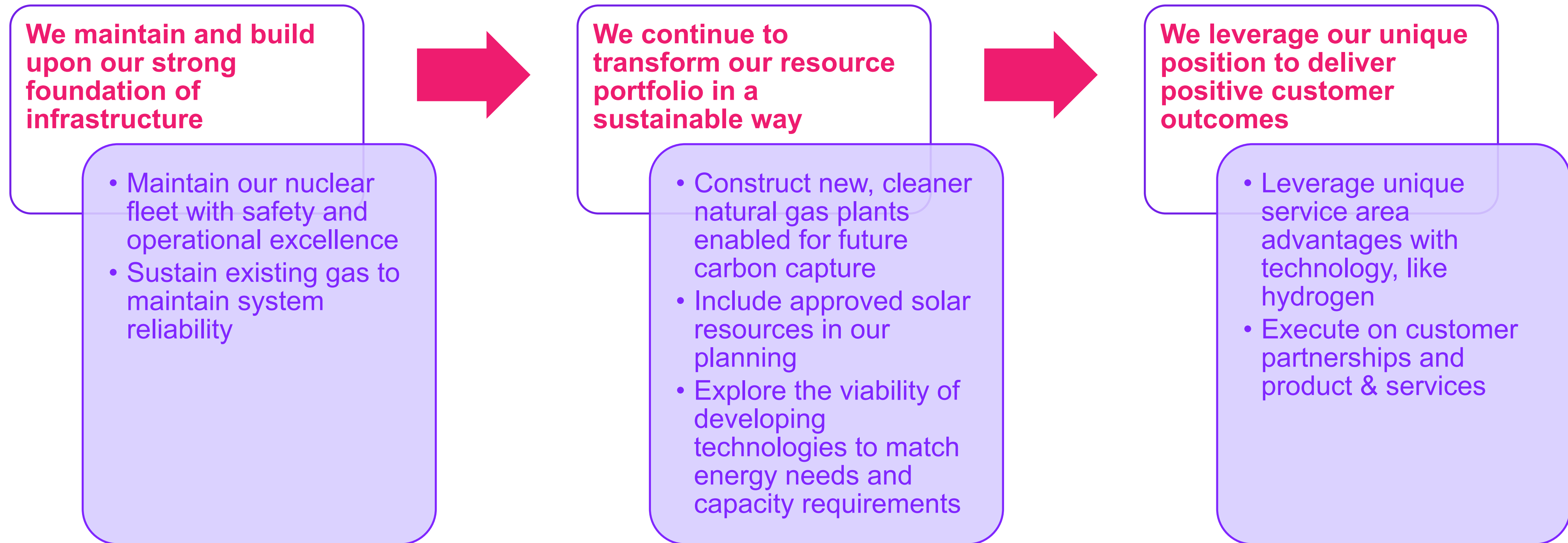
**Long-Term Planning
Objectives and Principles**

Key Resource Planning Objectives

1. ELL's resource planning process is based on a set of principles designed to reliably meet customer power needs at the lowest reasonable cost while reducing emissions, improving reliability and resilience performance, and minimizing customer risk exposure. While the landscape within the electric utility industry is changing, these principles remain the consistent factors underpinning our long-term planning strategy.
2. The IRP plays an important role in the iterative process of planning ELL's future resource portfolio by providing a comprehensive and transparent look at long-term themes and tendencies that may affect resource planning decisions.
3. This strategy provides the flexibility for ELL to respond and adapt to a constantly shifting utility landscape and customer demand.



Planning Principles



IRP Objective

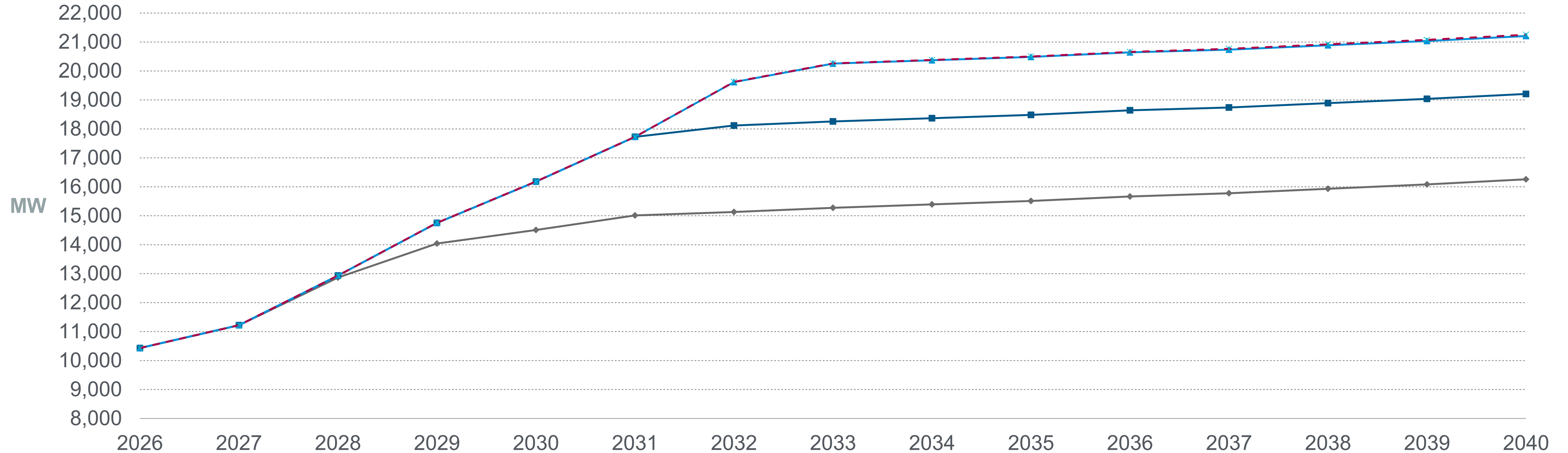
- An IRP is a planning process and framework in which the costs and benefits of supply-side and demand-side alternatives are evaluated to develop resource portfolio options that help meet ELL's planning objectives.
- Through the IRP process, ELL will conduct a study of customer needs over the next 20 years based on currently available data. This Study will analyze resource portfolios under a variety of economic scenarios and evaluate the impact of different fuels and technologies. Results of the IRP are not intended as static plans or pre-determined schedules for resource additions.

02

**Assessment of Resource
Need**

ELL IRP Scenarios - Peak Forecasts

MISO Summer Season Coincident Peak Estimates

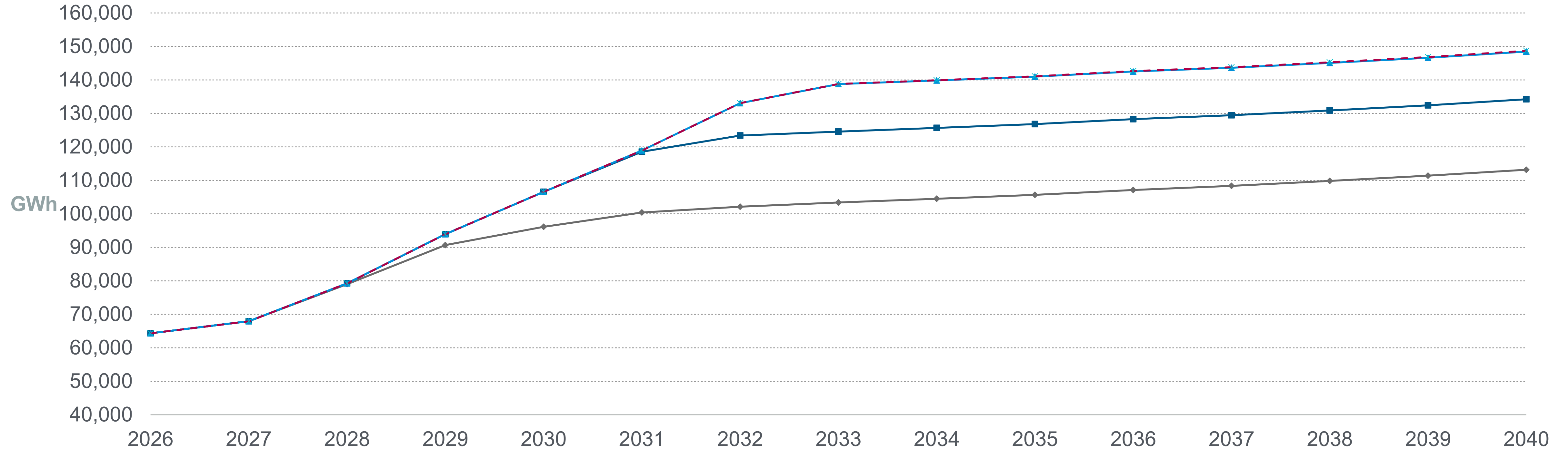


Amounts in MW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Low	10,432	11,221	12,866	14,042	14,509	15,013	15,131	15,276	15,392	15,511	15,667	15,777	15,931	16,085	16,260
Reference	10,432	11,221	12,935	14,755	16,182	17,725	18,117	18,257	18,370	18,484	18,643	18,737	18,889	19,037	19,207
High	10,432	11,221	12,935	14,755	16,182	17,725	19,617	20,257	20,370	20,484	20,643	20,737	20,889	21,036	21,207
Alt	10,432	11,220	12,935	14,755	16,183	17,727	19,621	20,263	20,380	20,499	20,659	20,765	20,921	21,074	21,251

Scenario estimates as of Apr 2026

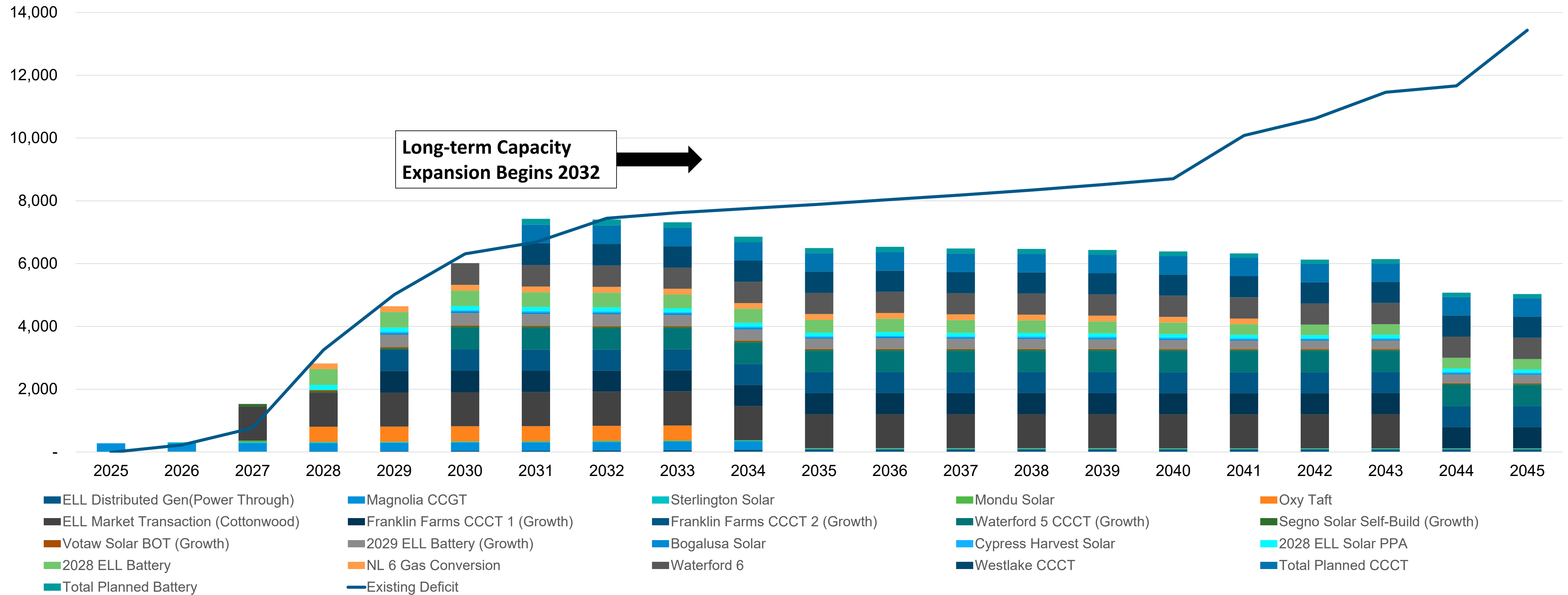
ELL IRP Scenarios - Energy Forecasts

Energy Scenario Estimates



Scenario estimates as of Apr 2026

ELL 20-Year Resource Need



Surplus/(Deficit)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
BP26 Summer	287	89	764	(427)	(370)	(294)	744	(41)	(303)	(898)	(1,393)	(1,504)	(1,700)	(1,873)	(2,081)	(2,315)	(3,756)	(4,492)	(5,314)	(6,590)	(8,402)

ELL 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

Unit	ELL Ownership Share [MW]	Resource Type	Unit [cont.]	ELL Ownership Share [MW, cont.]	Resource Type [cont.]
Acadia	520	Owned Resource/ Affiliate PPA	Roy Nelson 6	208	Owned Resource/ Affiliate PPA
ANO 1	22		JWLPS	911	
ANO 2	26		Union 3	512	
Big Cajun 2 3	135		Union 4	513	
Calcasieu 1	142		Waterford 2	410	
Calcasieu 2	155		Waterford 3	1,056	
Independence 1	7		Waterford 4	29	
LCPS	980		White Bluff 1	7	
Little Gypsy 2	396		White Bluff 2	12	
Little Gypsy 3	485		WPEC	366	
Ninemile 4	716		Agrilectric	9	Third Party PPA
Ninemile 5	725		Capital Region Solar	49	
Ninemile 6	442		Carville	487	
Ouachita 3	245		Oxy-Taft	471	
Perryville 1	338		Rain CII	13	
Perryville 2	100		Elizabeth Solar	124	
Perryville 2	101		Sterlington Solar	49	
Riverbend 30	192		Sunlight Road	49	
Riverbend 70	393		Vidalia	125	
			Interruptible Load ¹	248	

Deactivation and Contract Expiration Assumptions

- As resources age and assumed deactivation dates near, as equipment failures occur, or as operating performance diminishes, cross-functional teams are assembled to evaluate whether to keep a particular unit in service for a specified amount of time and level of reliability.
- Near-term BP26 deactivation assumptions are detailed below.

Plant	Unit	Deactivation Assumption
Big Cajun 2	3	2028
Waterford	2	2028
Little Gypsy	2,3	2030
Roy Nelson	6	2028
White Bluff	1,2	2028
Independence	1,2	2030

PPA	Fuel	Deactivation Assumption
Vidalia	Hydro	2031

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Analytical Framework

Futures

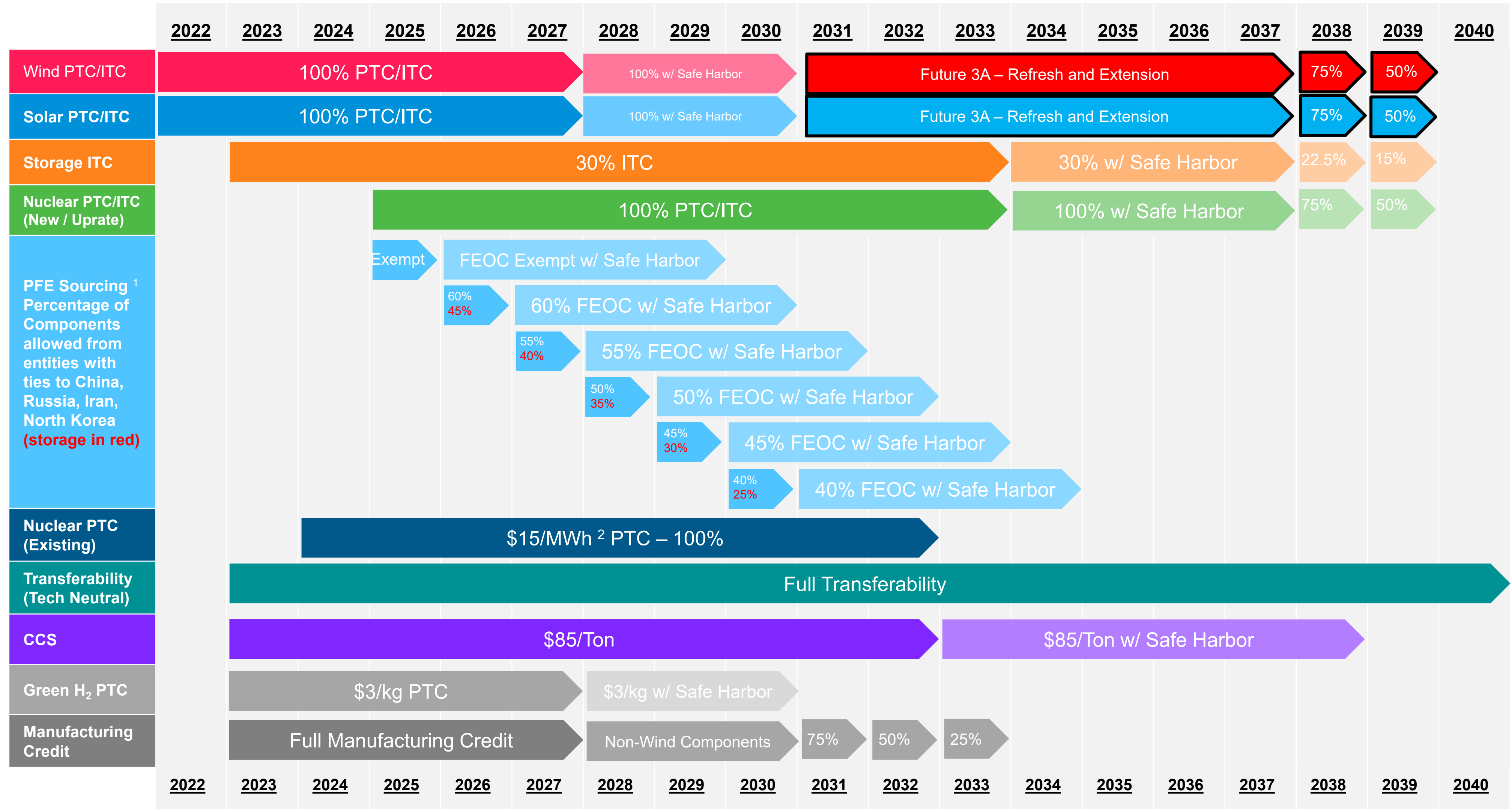
- The IRP analysis will rely on 3 futures to assess supply portfolios across a range of market outcomes.
- The future approach, along with sensitivities, will allow ELL to assess portfolio performance as it is related to expected total supply cost and risk.
- Due to various uncertainties, some of the future inputs are still being discussed. Revisions to the futures matrix below may be necessary as new information becomes available.

	Future 1	Future 2	Future 3	Future 3A
ELL Peak Load & Energy Growth	Low (BP26)	Reference	High	High
MISO Peak Load & Energy Growth	1.1% CAGR CP / 1.5% CAGR Energy	1.6% CAGR CP / 2.28% CAGR Energy	2.0% CAGR CP / 2.9% CAGR Energy	2.0% CAGR CP / 2.9% CAGR Energy
Natural Gas Prices	Reference	Reference	High	High
MISO Generation Deactivations¹	MISO Series 2, Future 1 Assumptions	MISO Series 2, Future 2 Assumptions	MISO Series 2, Future 3 Assumptions	MISO Series 2, Future 3 Assumptions
ITC/PTC Assumptions	Current Law	Current Law	Current Law	45Y / 45Q refresh/extension
DSM Potential Study (ELL DR)	Economic optimization	Economic optimization	Economic optimization	Economic optimization
DSM Potential Study (other DER)	Reference: Current Law Scenario	High: Current Law Scenario	High: Current Law Scenario	Reference: Alt Policy Scenario
Technology Options Available	All	All	All	CCCT only eligible w/CCS

1. Deactivation assumptions will be consistent with current planning assumptions for ELL owned or contracted generation

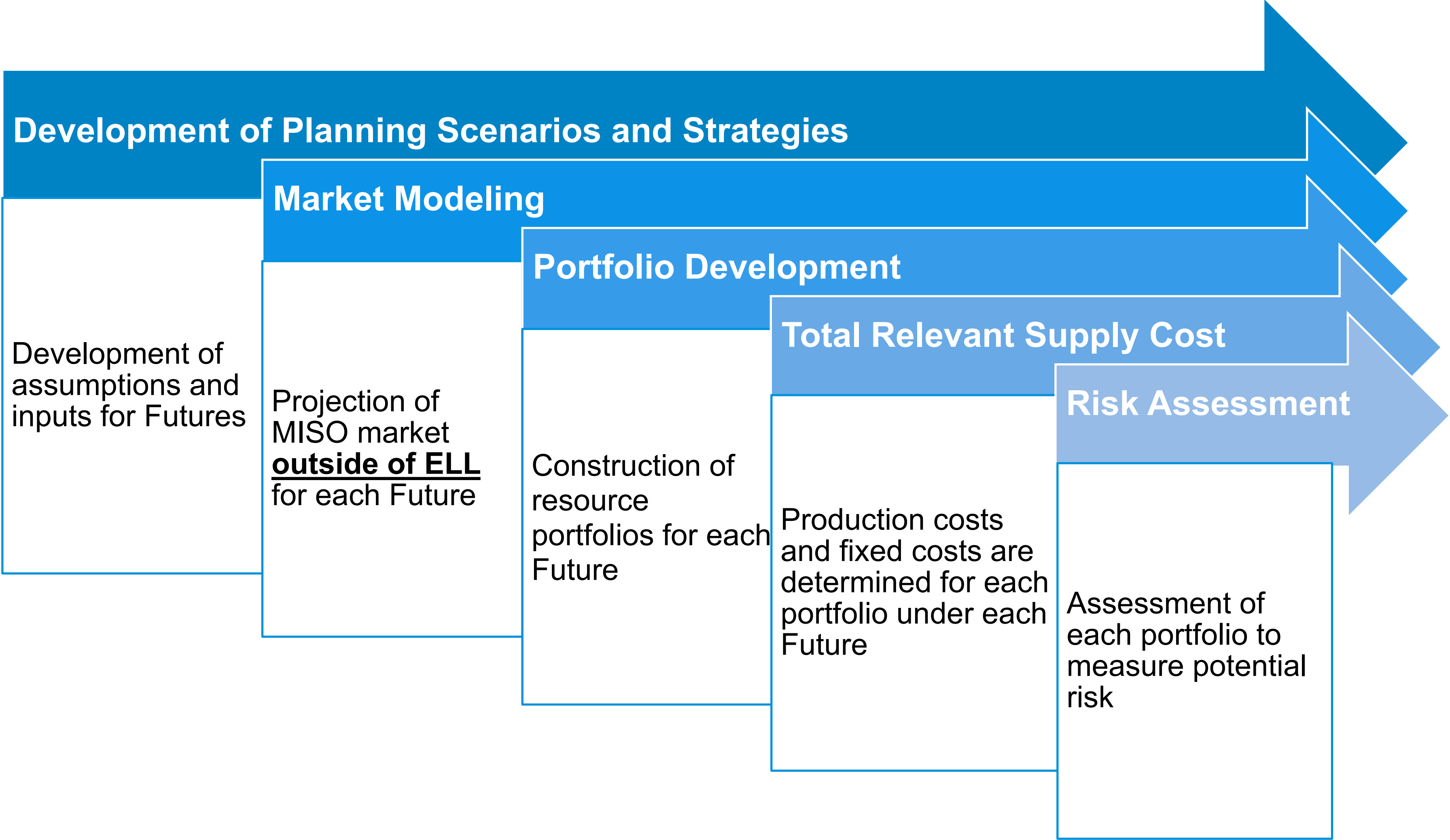
Tax Credit Assumptions

Tax Credit Timeline



1. For solar, wind, and battery projects the percentages represent the maximum content allowed from prohibited foreign entities to maintain tax credit eligibility.
2. Existing nuclear PTC amount is reduced as gross receipts increase.

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 TBD

Portfolios Futures	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

04

Supply Alternatives

Technical Assessment

Evaluation of cost and performance for new generation and storage technologies

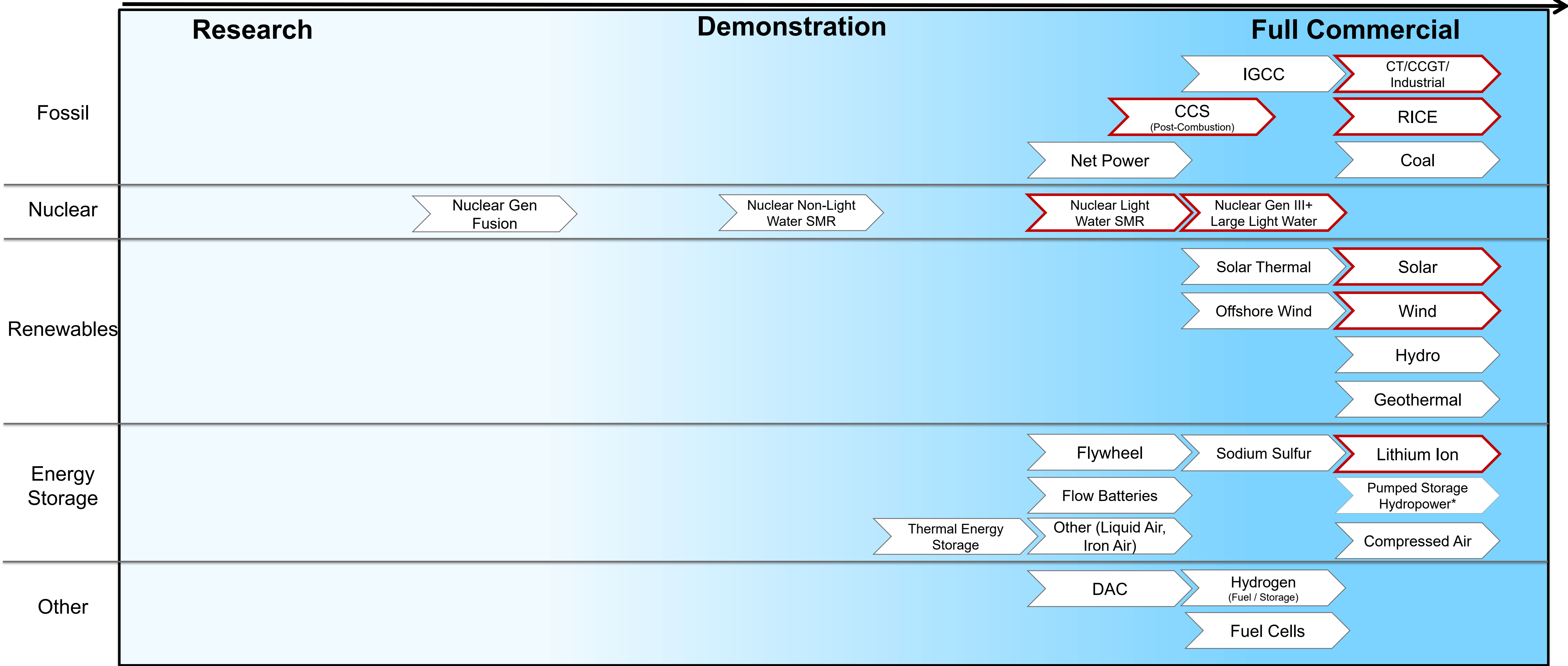


- Affordability**
 - Capital cost
 - O&M cost
 - Energy output / capacity factor
 - Fuel costs / requirements
 - Deployment risk
- Reliability**
 - Technology maturity
 - Performance (e.g., Dispatchability / load carrying capability)
 - Durability
 - Service territory feasibility
- Sustainability**
 - Environmental impact
 - Regulatory/legislative directives, policy trends
 - Customer needs (e.g., time matching)

Technology Readiness Level

Rating	1	2	3	4	5	6	7	8	9
Phase	Research	Research	Research	Research	Research	Development	Demonstration	Deployment	Mature
Description	Concept	Formulation	Proof of Concept	Lab Prototype	Lab Scale	Pilot	Demonstration	Early Commercial	Fully Commercial

Technology Readiness



 Resource progressing to full assessment

*Pumped Storage hydropower requires specific geography conditions limiting applicability; evaluated for targeted location

Technology Screening

Technology is screened based on the Technology Readiness Level and the alignment to our Planning Objectives; the refined list is then assessed from a techno-economic perspective

Technologies Reviewed for Screening

Combustion & Combined Cycle Gas Turbines (CT/CCGT)
| Reciprocating Internal Combustion Engines (RICE)
| Integrated Gasification Combine Cycle Coal (IGCC)
| Carbon Capture and Storage (CCS) and Direct Air Capture (DAC) | Solar | Wind | Battery Energy Storage Systems (BESS) | Mechanical Storage (Compressed Air, Liquid Air, Flywheel) | Thermal Energy Storage (Concrete/Sand/Electro/Molten Salt) | Geothermal, Hydro, Hydro Pump Storage | Nuclear Gen III (Large and SMR Light Water Reactors) | Nuclear Gen IV Non-Light Water SMR and Gen Fusion | Fuel Cells | Net Power Allam Cycle
| Other fuels: Coal, Pulverized Coal, Hydrogen, Landfill Gas

Planning Objectives &
Technology Readiness Level

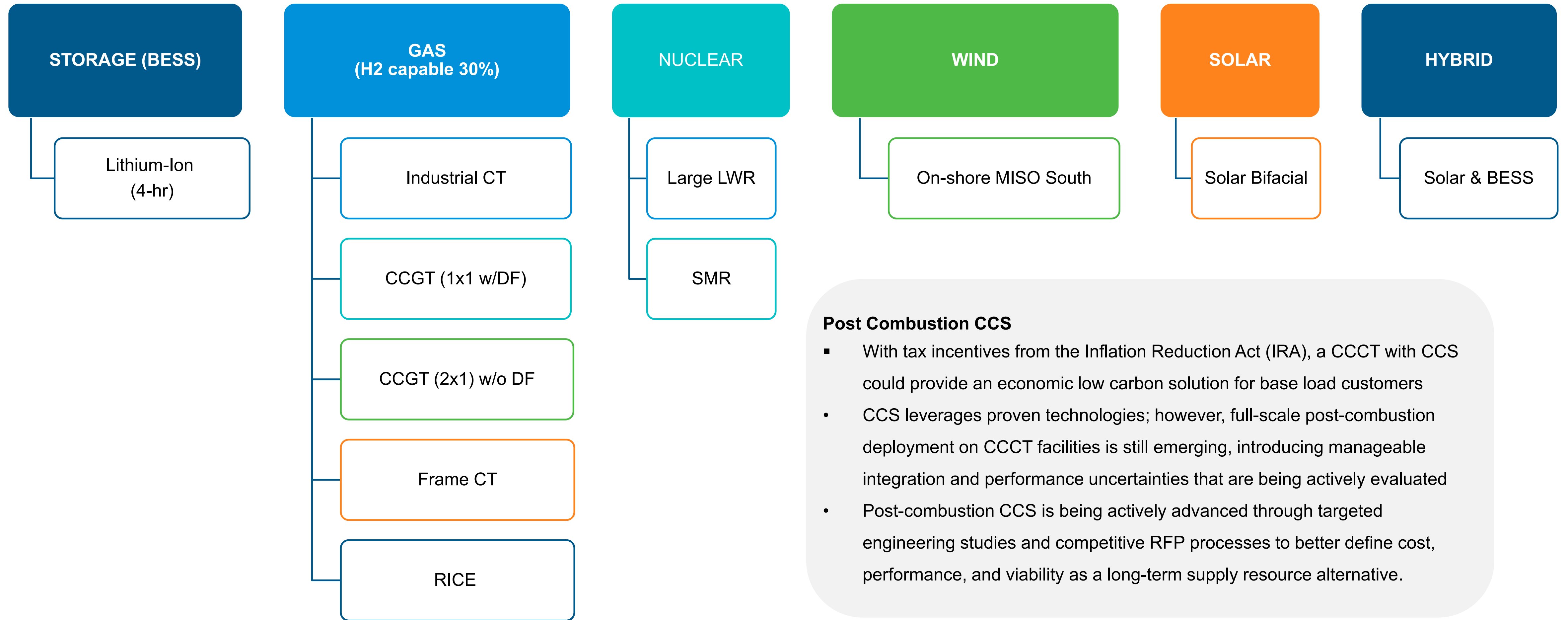
Technologies Progressed to Full Assessment

Combustion Turbines (CT) | Combined Cycle Combustion Turbines (CCCT) | Reciprocating Internal Combustion Engines (RICE) | Carbon Capture and Storage (CCS) | Solar | Wind | Battery Energy Storage Systems (BESS) | Nuclear Gen III (Large and SMR Light Water Reactors)

Noted Screened Technologies

- Nuclear Gen IV: no wide-spread commercial use, significant unknowns associated with the supply chain, constructability and long-term operation; continuing to monitor and actively investigate
- Geothermal: location dependent requiring exploratory funding (with limited pilots in region), studies have not been favorable in the region for cost and scale; enhanced technologies are emerging and continue to be monitored for maturity, cost and scale

Identified Supply-Side Resource Alternatives



Post Combustion CCS

- With tax incentives from the Inflation Reduction Act (IRA), a CCCT with CCS could provide an economic low carbon solution for base load customers
- CCS leverages proven technologies; however, full-scale post-combustion deployment on CCCT facilities is still emerging, introducing manageable integration and performance uncertainties that are being actively evaluated
- Post-combustion CCS is being actively advanced through targeted engineering studies and competitive RFP processes to better define cost, performance, and viability as a long-term supply resource alternative.

Cost and Performance Assumptions

Thermal Resources

Technology	First Year Available for Modeling	Installed Capital Cost Nominal [\$/kW]	Fixed O&M L. Real [2025\$/kW-yr]	Variable O&M L. Real [2025\$/MWh]	Full HHV Summer Heat Rate [Btu/kWh]	Summer Net Maximum Capacity [MW]	Assumed Capacity Factor [%]	Life [Yr.]	H2 Capable (%)
CCGT (1x1) w/ duct firing	2032	\$2,705	\$14.54	\$4.80	6,816	733	73%	30	30%
Co-located two CCGT (1x1) w/ duct firing	2032	\$2,583	\$13.88	\$4.80	6,816	1,466	73%	30	30%
CCGT (2x1) w/ duct firing	2032	\$2,332	\$10.04	\$4.67	6,809	1,466	73%	30	30%
1 x Industrial Turbine	2032	\$4,497	\$45.08	\$12.47	9,840	54	30%	30	30-75%
3 x Industrial Turbine	2032	\$3,564	\$20.87	\$12.47	9,840	163	30%	30	30-75%
7 x Industrial Turbine	2032	\$3,019	\$14.73	\$12.47	9,840	380	30%	30	30-75%
F Class without SCR	2032	\$2,790	\$13.04	\$7.53	10,230	225	10%	30	20%
F Class with SCR	2032	\$3,085	\$13.10	\$7.70	10,280	224	10%	30	20%
RICE Option A	2032	\$4,796	\$43.38	\$14.10	8,370	110	20%	30	25%
RICE Option B	2032	\$4,246	\$31.80	\$14.10	7,510	150	20%	30	25%
CT-J	2033	\$2,660	\$8.11	\$6.90	9,177	422	10%	30	30%
Nuclear (2x Large LWR) ¹	2037	\$18,490	\$148.72 ²	- ²	10,000 ³	2,234	93%	40 ⁴	N/A
Nuclear (3x4 SMR) ¹	2034	\$14,965	\$149.71 ²	- ²	10,000 ³	960	96%	40 ⁴	N/A

Notes:

1. New nuclear technology assessment is based on high level internal estimate and subject to changes; limited deployment in US, current working perspective as we continue to consider the resource type.
2. Not enough details to differentiate VOM and FOM yet; all O&M costs currently included as FOM; costs do not include fuel.
3. Nuclear HR is listed here for illustrative purpose only. Current new nuclear assessment directly use \$/MWh fuel cost assumption.
4. Internal LCOE assessment used 40-yr life horizon; however, new nuclear reactors may operate 80 years with license renewals/extensions.

Cost and Performance Assumptions

Natural Gas Resources

Cost Assumption Clarifications:

1. Installed capital costs for gas conventional generation w/hydrogen (H2), include only the capital associated with preserving the optionality to burn H2, except for RICE Units (see note 2). The costs for H2 co-firing capability are values from CTG OEMs for H2 capability upgrades. BOP modifications including upgraded materials, purge system, optical fire detection, blending skids, duct burner upgrades, and emission control upgrades are not included in these costs.
2. RICE: Currently costs and performance impacts of hydrogen firing capability is excluded.
3. Based on MISO South
4. Sales tax is specific to each Operating Company and is included in the EPC
5. Combined cycle capital costs assume a power island scope of supply from the CTG manufacture in which the CTG OEM will also supply the STG and HRSG.
6. All \$/kW costs are based on net facility performance at the summer ambient condition. (See performance note 3)
7. Installed Capital Cost includes EPC cost, Sales Tax, Owner's direct/indirect cost, AFUDC and Contingency. Owner's direct and indirect costs is composed of Engineering/Consultants, Expenses, Tools and Materials, Payroll, Materials and Supplies Loaders, Depreciation, Capital Suspense, Payroll Loaders, & Entergy Overheads. AFUDC is included. Owner's Contingency is set at 10% of EPC cost.
8. Fixed O&M Costs include manufacturer's service agreement, labor, consumables, maintenance and minor repairs, asset management, administrative and general expenses. Excludes property taxes or land lease, insurance, fuel supply and delivery contract costs.
9. Variable O&M Costs include major hours-based maintenance, variable consumables including catalysts, chemical and water usage. Excludes fuel costs and emission offset purchases.
10. Total interconnection costs are **NOT** included. See "Transmission Interconnection Adders" slide for cost estimating guidance.
11. CAPEX cost shown reflects the expected cost for a resource aligned with the year when a resource is expected to come online.

Performance Assumption Clarifications:

1. For options with duct firing and H2 co-firing, the co-firing is assumed to only be used in the CTG. HRSG duct burner will used 100% natural gas fuel.

Cost and Performance Assumptions

Natural Gas + Hydrogen Resources

O&M Cost Definitions

Item	Definition/Inclusion
Fixed O&M	<p>FOM costs are those associated with day-to-day operations and maintenance that do not vary significantly with a plant's electricity generation. The FOM roll-up value includes fixed long term service agreement (LTSA) costs, regular staffing labor costs, maintenance and minor repairs, consumables, general and administrative costs. A major maintenance cost component is included to account for the plant's costs incurred during a major overhaul events and is estimated based on the assumed capacity factor and corresponding engine run hours.</p> <p>Property taxes, land lease costs, firm gas contract fees, and insurance would also be considered fixed costs, but have been excluded from these estimates due to the high degree of location-specific variability.</p>
Variable O&M	<p>VOM costs are those associated with operational and maintenance activities that directly correlate with the plant's electrical generation. The VOM roll-up value includes the LTSA related major maintenance labor and parts, catalyst replacements, reagent consumptions, water supply and discharge costs, and other chemical and consumable costs.</p>

Cost and Performance Assumptions

Solar Resources

Technology	First COD Year	Installed Capital Cost [Nominal \$/kWac] ^{1,5,12}	Fixed O&M L. Real [2025\$/kW-yr.] ⁴	Max Summer Capacity [MW-ac]	Assumed Capacity Factor [%] ⁵	Life [Yr.]	DC:AC Ratio [%]	Degradation [%]
Utility-Scale Solar ¹	2028	\$1,847	\$17.42	<u>200 MW</u>	25.95%	30	1.3	0.5% per year
Hybrid: Solar + BESS ²	2028	\$2,847	\$27.30	<u>200MW</u> 160MW/640MWh	25.95%	30 (Solar) / 20 (BESS)	1.3	0.5% per year (Solar only)

Notes:

1. Utility-Scale: Pricing is indicative of a generic “self-build and BOT style” project and intended to be generic. Installed Capital Cost includes EPC cost, Sales Tax, Owner’s direct/indirect cost, AFUDC and Contingency. Owner’s direct and indirect costs is composed of Engineering/Consultants, Expenses, Tools and Materials, Payroll, Materials and Supplies Loaders, Depreciation, Capital Suspense, Payroll Loaders, & Entergy Overheads. AFUDC is included. Owner's Contingency is set at 10% of EPC cost.
2. Hybrid Solar + BESS: Based on 200MW + 160 MW / 640 MWh – (\$/kW on 200MW base.)
3. Total interconnection costs of 200MW facility are **NOT** included. See "Transmission Interconnection Adders" slide for cost estimating guidance.
4. Solar and Hybrid Fixed O&M excludes property tax, insurance, and market participation type cost; Solar and Hybrid includes inverter replacement in year 15. Land lease costs represent \$5/kw-yr nominal and \$4.80/kw-yr levelized real.
5. On-system - Utility-scale Solar and Hybrid Capacity Factor will increase each year by an average of 0.3% for each new build resource built after 2028 (e.g., 25.95% in year 1 to 26.03% in year 2). CF base case is based on internal PVSyst Model . Capacity factor includes all losses up through GSU HV side.
6. CAPEX cost shown reflects the expected cost for a resource aligned with the year when a resource is expected to come online.
7. Land cost is not included.

Resource Accreditation Assumptions

Dispatchable Resources

- Capacity credit will be calculated by applying MISO's Schedule 53 class average ISAC/ICAP ratios and UCAP/ISAC conversion ratios to the identified resource alternatives.

Renewable Resources

- Capacity credits will be determined by the Dynamic Peak Credit function within Aurora. This function calculates the peak credit for each type of renewable resource for each iteration of the long-term capacity expansion run based on the penetration of total renewables in the previous iteration. The top 3% of peak load hours per month, net of solar, wind, and hydro resource output are used to determine how much PRM contribution a resource type will have in a season.

Battery Storage

- Battery capacity accreditation will be based upon MISO's Regional Resource Assessment Direct Loss of Load ("DLOL")

Cost and Performance Assumptions

Wind Resources

Technology	First COD Year	Installed Capital Cost Nominal [First Year Installed \$/kWac] ^{1,2}	Fixed O&M L. Real [2025\$/kW-yr.] ⁴	Max Summer Capacity [MW-ac]	Assumed Capacity Factor [%] ⁵	Life [Yr.]
Onshore wind	2028	\$2,827	\$38.26	100 - 200	32.1%	30

Notes:

1. Capital cost includes all costs prior to the point of transmission Interconnection. EPC costs align with estimated hub heights between 98-117m for on-shore wind.
2. Pricing is indicative of a “self-build and BOT style” project and intended to be generic. Land is assumed to be leased, no cost for land purchase is included.
3. Owner's Contingency is 10% of EPC cost and AFUDC.
4. On-shore Wind Fixed O&M excludes property tax and insurance. Includes land lease, which is \$3.42/kw-year levelized real.
5. Onshore wind capacity factor will increase each year by an average of 0.1% for each new build resource built after 2028. Capacity Factor based on Entergy representative MISO South resource with adequate performance (On-shore Wind excluding South LA and New Orleans)
6. Capital and O&M costs are asset cost only and do not include transmission capital, O&M, or transmission service costs. HVDC options for off-system wind are not included
7. CAPEX cost shown reflects the expected cost for a resource aligned with the year when a resource is expected to come online.

Cost and Performance Assumptions

Battery Energy Storage Systems

Technology	Installed Capital Cost [Nominal\$/kWac] ¹	Fixed O&M L. Real [2025\$/kW-yr.] ²	Max Summer Capacity [MW-ac]	Round-trip Efficiency (RTE) [%]	Life [Yr.]
Storage (4hr, Li-Ion)	\$2,031	\$15.44	100MW/ 400MWh	87%	20
Storage (8hr, Li-Ion)	\$3,132	\$28.40	100MW/ 800MWh	87%	20

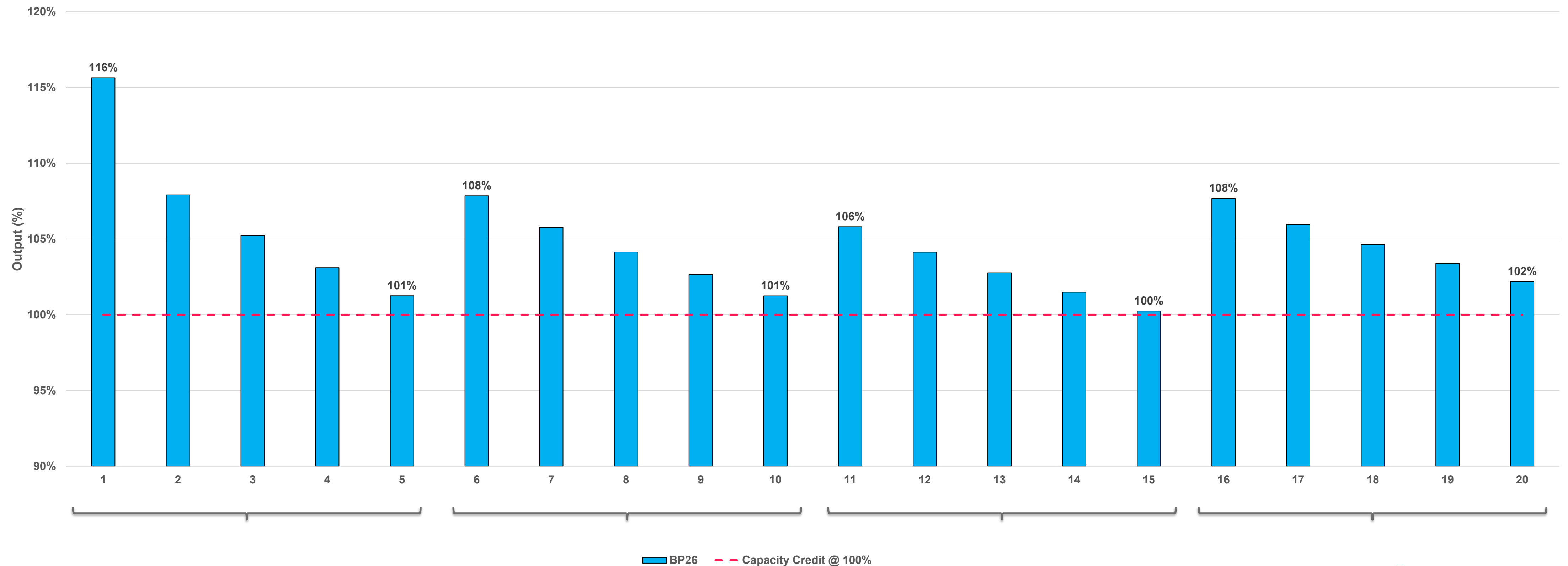
Notes:

1. Includes 16% initial oversizing in year 1 to account for Depth of Discharge (DoD), followed by an additional augmentation every five years (year 6, 11, and 16) via partial module replacement. Total Installed Capital Cost estimate is applicable to any battery with a capacity greater than 50 MW.
2. Excludes property tax and insurance.
3. CAPEX cost shown reflects the expected cost for a resource aligned with the year when a resource is expected to come online. However, these costs are assumed to be identified several years prior to COD.

BP26 Battery Degradation/Depth of Discharge

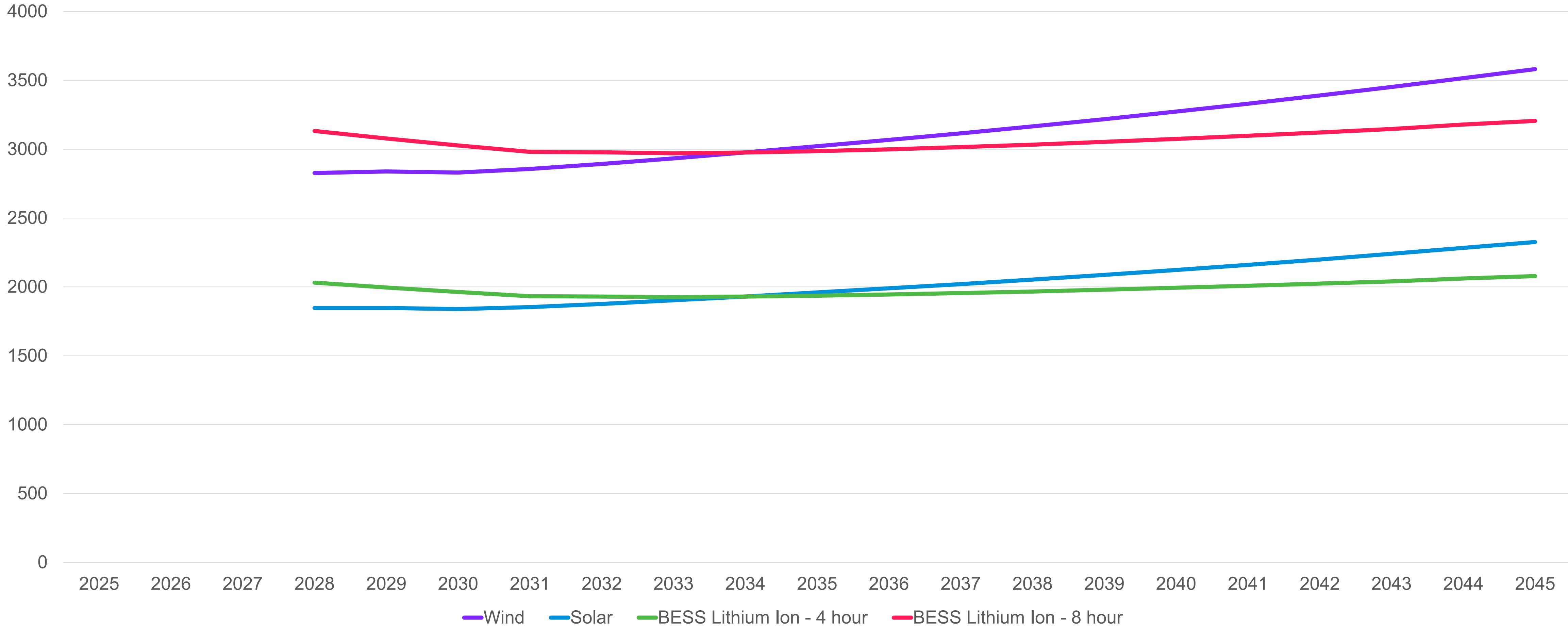
Assuming initial oversizing and capacity augmentation throughout the 4-hr discharge battery's life, battery assumed to operate at no less than 100% capacity. Planning models will assume no degradation and the battery will maintain 100% capacity credit throughout its life.

- Battery Installed Capital Cost includes 16% initial oversizing in year 1 to account for Depth of Discharge (DoD), followed by an additional 6-8% augmentation every five years (year 6, 11, and 16) via partial module replacement.



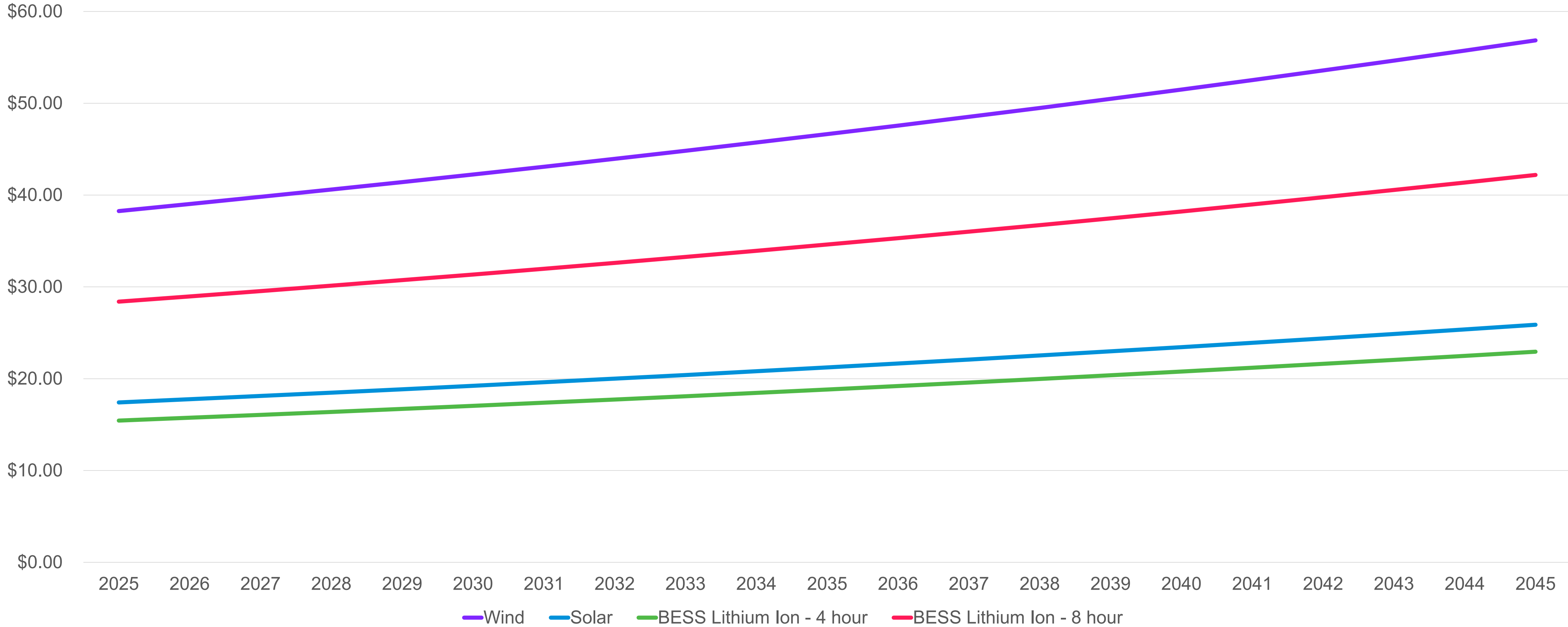
Renewable Installed Capital Cost Curves

Nominal \$/kW



Renewables Fixed O&M Cost Curve

Levelized Real \$/kW



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 in MISO Local Resource Zone 9
- Market (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
- Market (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

Transmission Interconnection Adders

Excluding Transmission Network Upgrades

Example Use: New POI Cost (2025\$)

Project Size (MW)	Cost (\$ millions)	Description
X<399 MW	16	(115,138,161 kV) = POI substation (3 breaker ring) + t-line adjustments (cut-ins) + remote end work (line panels)
399≤X≤799	20	(230 kV) = POI substation (3 breaker ring) + t-line adjustments (cut-ins) + remote end work (line panels)
X>799	50	(500 kV) = POI substation (3 breaker ring) + t-line adjustments (cut-ins) + remote end work (line panels)

Example Use: Brownfield POI Cost (2025\$)

Project Size (MW)	Cost (\$ millions)	Description
X<399 MW	7	(115,138,161 kV) = POI Add node to existing substation
399≤X≤799	9	(230 kV) = POI Add node to existing substation
X>799	15	(500 kV) = POI Add node to existing substation

General Interconnection Cost:

- Cost required for collector station and power conversion equipment. Includes electrical infrastructure from generation unit to Transmission POI.

Transmission Interconnection Cost:

- Cost required for Transmission to build POI substation, transmission line work, and remote end coordination.
- **Excludes:**
 - Network Resource Interconnection Service (NRIS)
 - External Resource Interconnection Service (ERIS)
 - Interconnection Service (IS) = NRIS + NRIS Local + ERIS
 - Off System interconnections
- All interconnection cost will be project specific and are generalized for ease of estimating purposes. This chart covers many typical options and is meant to be used as guidance. It does not cover the plethora of options that can or may exist for interconnection arrangements for all generating resources.

Example Use:

- NEW POI Solar Facility
 - 100MW Solar New Build – New POI @ 230 kV
 - + \$20M for Transmission Interconnection Cost (\$200/kW)
 - (If voltage class is known it should override project capacity size when determining cost)
- Existing POI Natural Gas Facility (Near Existing Transmission Substation)
 - 1000MW CCGT – Brownsfield POI @ 230 kV (<800MW each)
 - 3 Interconnections @ 230 kV (2 CTG + 1 STG)
 - + \$27M (9+9+9) for Transmission interconnection Cost (\$21/kW)

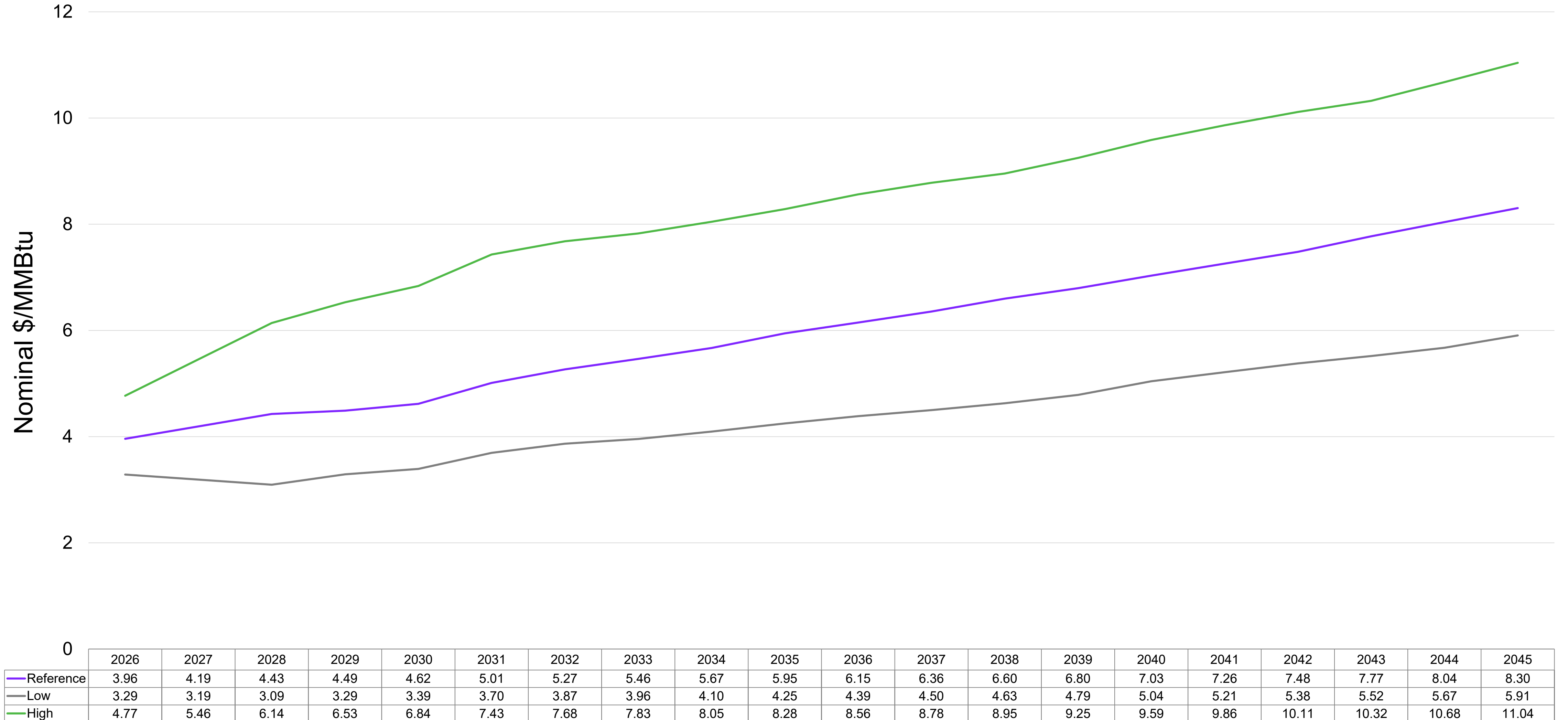
DSM Potential Study

- ICF has been retained by ELL to perform a DSM potential study
- The study considered scenarios to create savings forecasts for DSM programs:
 - DER study:
 1. Reference case
 2. High case
 - EE study:
 1. Reference Case(based on existing ELL programs with expanded budgets)
 2. High Case (existing programs plus new best practice programs)
 - DR study:
 1. Reference case
 2. High case
- In addition to the Reference and High Case studies, ICF has also done an alternative Federal Policy Scenario for all studies which aligns with Future 3A's assumptions for ITC/PTC.
- Hourly load shapes 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.

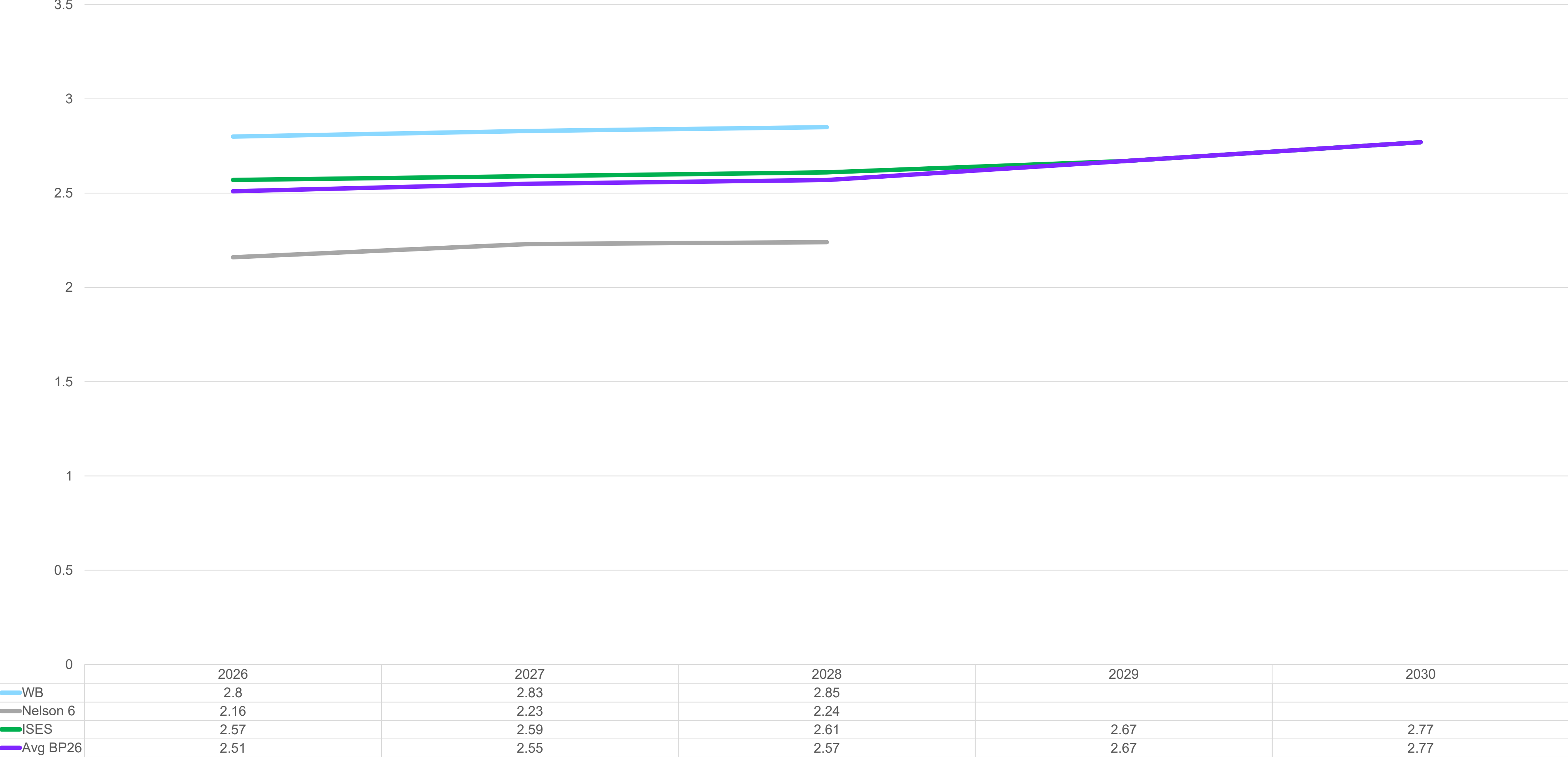
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Modeling Assumptions

BP26 Henry Hub Gas Price Forecast

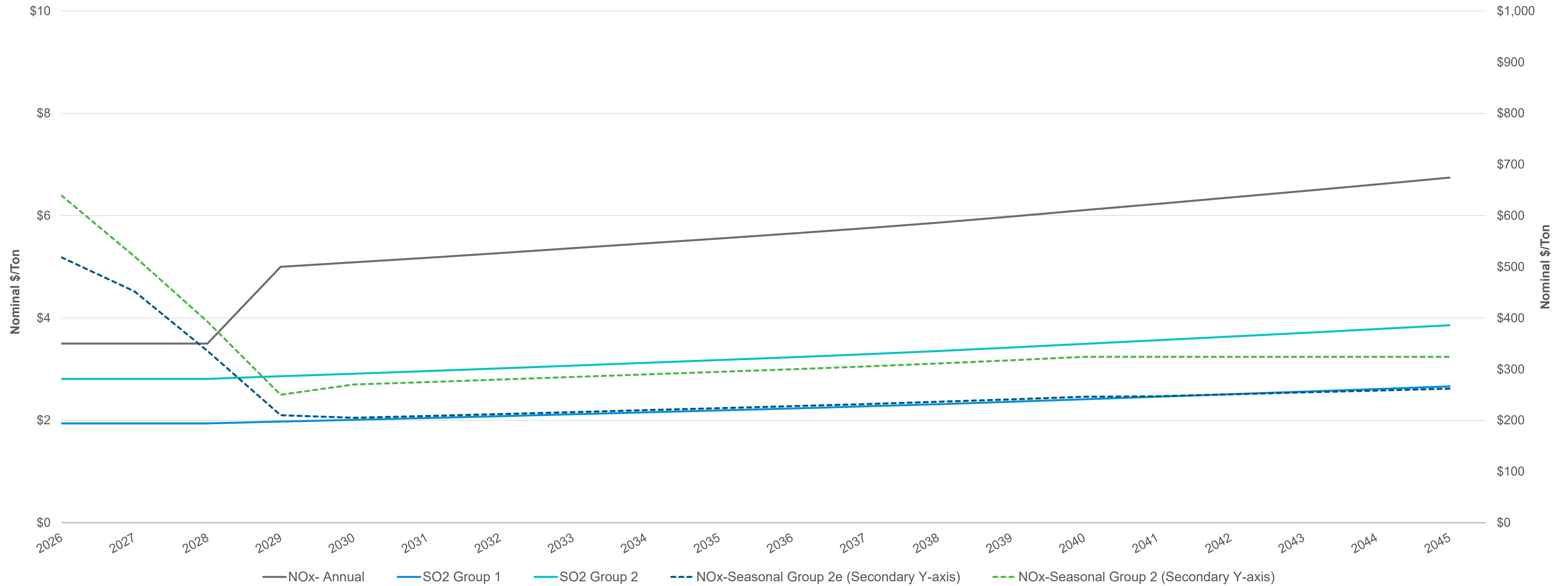


BP26 Coal Price Forecast



• Average BP26 Coal price based on average of White Bluff, ISES and Nelson delivered coal price forecast.

BP26 NOx and SO2 Price Forecast



	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
NOx- Annual	\$3.50	\$3.50	\$3.50	\$5.00	\$5.09	\$5.18	\$5.27	\$5.36	\$5.46	\$5.55	\$5.65	\$5.75	\$5.86	\$5.98	\$6.11	\$6.23	\$6.35	\$6.48	\$6.61	\$6.74
SO2 Group 1	\$1.94	\$1.94	\$1.94	\$1.98	\$2.01	\$2.04	\$2.08	\$2.12	\$2.16	\$2.19	\$2.23	\$2.27	\$2.32	\$2.36	\$2.41	\$2.46	\$2.51	\$2.56	\$2.61	\$2.66
SO2 Group 2	\$2.81	\$2.81	\$2.81	\$2.86	\$2.91	\$2.96	\$3.01	\$3.07	\$3.12	\$3.18	\$3.23	\$3.29	\$3.35	\$3.42	\$3.49	\$3.56	\$3.64	\$3.71	\$3.78	\$3.86
NOx-Seasonal Group 2e (Secondary Y-axis)	\$518.57	\$452.02	\$335.60	\$210.00	\$205.00	\$208.56	\$212.28	\$216.12	\$219.91	\$223.74	\$227.68	\$231.82	\$236.25	\$241.01	\$246.11	\$247.10	\$250.78	\$254.45	\$258.13	\$261.80
NOx-Seasonal Group 2 (Secondary Y-axis)	\$639.40	\$520.24	\$392.74	\$250.00	\$270.00	\$274.69	\$279.58	\$284.64	\$289.64	\$294.68	\$299.87	\$305.32	\$311.15	\$317.43	\$324.14	\$324.14	\$324.14	\$324.14	\$324.14	\$324.14

CO₂ Pricing Assumptions

Background

- Since 2012, Entergy's corporate point of view on power sector CO₂ pricing has relied on ICF outlooks.
- ELL's IRPs and other public statements (discovery responses, testimony) have stated that the forecasted CO₂ price serves as a proxy for future costs related to regulation of greenhouse gas emissions (such as Clean Air Act 111 standards).
- The ICF CO₂ outlook has been used in economic benefits analysis to compare the relative costs of new energy generating resources such as solar, wind, nuclear (uprates and new nuclear) to combined cycle units.
- ICF recently decided to abandon a federal CO₂ pricing assumption in its base case due to consistent lack of interest from Congress and the recent OBBBA budget reconciliation. The proposed EPA repeal of all greenhouse gas emissions standards for the power sector under Clean Air Act Section 111 further reinforces the ICF perspective around ongoing political misalignment on climate change.
- Other consultants that ELL retains for market intelligence data are similarly forecasting \$0 CO₂ pricing for the US power sector and MISO South states.
- Even without national legislation, Entergy customers may still be subject to future carbon costs (direct or indirect) through 1) CO₂ pricing for goods exported to the EU due to its Carbon Border Adjustment Mechanism consistent with the carbon intensity of Entergy's electric supply, 2) future EPA rules restricting CO₂, or 3) future presidential orders restricting fossil generation or requiring carbon capture.

Current Strategy

- ***Removed CO₂ pricing assumptions from BP26 and instead implement an assumed extension of 45U (existing nuclear) and an extension of 45Y (new nuclear, solar, wind, and battery) into scenario analysis such as IRPs and other portfolio studies.***

Capacity Value Forecast (HSPM)

Capacity Value (\$/kW-yr)		
Levelized Real CT w/ Hydrogen Capability		
	<u>ICAP</u>	<u>UCAP</u>
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		

Inflation Forecast and Financial Assumptions (HSPM)

2025 GDP POV	
Year	Inflation Rate
2025	
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	
2039	
2040	
2041	
2042	
2043	
2044	

- The financial discount rate to be used for present value calculations is ELL’s financial WACC [REDACTED]
- ELL’s WACC is used to assess present value for all potential resource additions to ELL’s portfolio

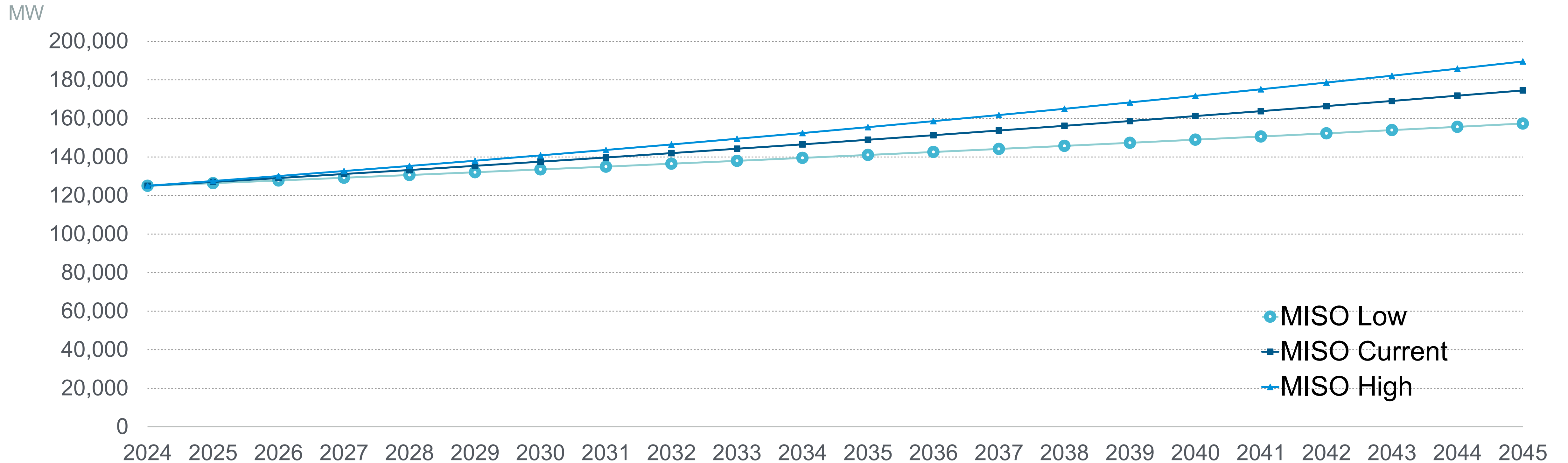
	Capital Ratios	Capital Costs	Return on Rate Base	Weighted Average Cost of Capital
Debt				
Preferred Stock				
Common Equity				
Total				[REDACTED]

Notes:

1. WACC as of September 2025

Tax Rate	[REDACTED]
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MISO Peak Load Forecast



[MW]	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MISO Low	125,041	126,416	127,807	129,213	130,634	132,071	133,524	134,993	136,478	137,979	139,497	141,031	142,583	144,151	145,737	147,340	148,960	150,599	152,256	153,930	155,624	157,335
MISO Current	125,041	127,042	129,074	131,140	133,238	135,370	137,535	139,736	141,972	144,243	146,551	148,896	151,278	153,699	156,158	158,657	161,195	163,774	166,395	169,057	171,762	174,510
MISO High	125,041	127,542	130,093	132,695	135,348	138,055	140,816	143,633	146,505	149,436	152,424	155,473	158,582	161,754	164,989	168,289	171,654	175,088	178,589	182,161	185,804	189,520

Notes:

1. Total MISO MW load values are displayed in the chart..

Electric Vehicle Assumptions

- The ELL load forecast developed for the current Reference Forecast (BP26) includes a conservative assumption around electric vehicles (EVs).
- The forecast has been lowered recently due to factors including:
 - Less support from the current executive branch of the federal government
 - Vehicle manufacturers starting to pivot towards hybrid vehicles and away from full battery EVs
 - Some continued tightness with markets and supply chain issues
- Relative to the assumed ceiling of numbers of EVs, the incremental 2040 energy in the table represents ~14% of passenger vehicles and ~24% of larger commercial/fleet vehicles being EV.

ELL EV Demand Additions* [GWh]	
2026	84
2027	133
2028	201
2029	288
2030	415
2031	578
2032	792
2033	1,071
2034	1,433
2035	1,901
2036	2,489
2037	3,213
2038	4,080
2039	5,109
2040	6,286

*Internally Developed Assumptions

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Timeline

Timeline - TBD

<u>Event</u>	<u>Current Deadline</u>	<u>Status</u>
<i>Filing initiating Fourth Full Cycle</i>	October 22, 2025	✓
<i>Survey of Stakeholders Survey Received</i>	December 22, 2025	✓
<i>File Data Assumptions</i>	January 21, 2026	✓
<i>First Stakeholder Meeting</i>	March 6, 2026	✓
<i>Stakeholders File Written Comments</i>	April 24, 2026	
<i>Draft IRP Filed</i>	October 22, 2026	
<i>Second Stakeholder Meeting</i>	November 20, 2026	
<i>Stakeholder Comments on Draft IRP</i>	January 22, 2027	
<i>Staff Comments on Draft IRP</i>	February 22, 2027	
<i>Final IRP Report Filed</i>	May 21, 2027	
<i>Stakeholders Submit disputed Issues List</i>	July 22, 2027	
<i>Staff Submits Recommendation</i>	August 23, 2027	
<i>Update Final IRP Report (if necessary)</i>	October 1, 2027	
<i>Commission Order</i>	October 22, 2027	