ELL 2023 IRP Data Filing-UPDATED

ENTERGY LOUISIANA: INTEGRATED SUPPLY PLAN

February 11th, 2022

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Creating sustainable value for all

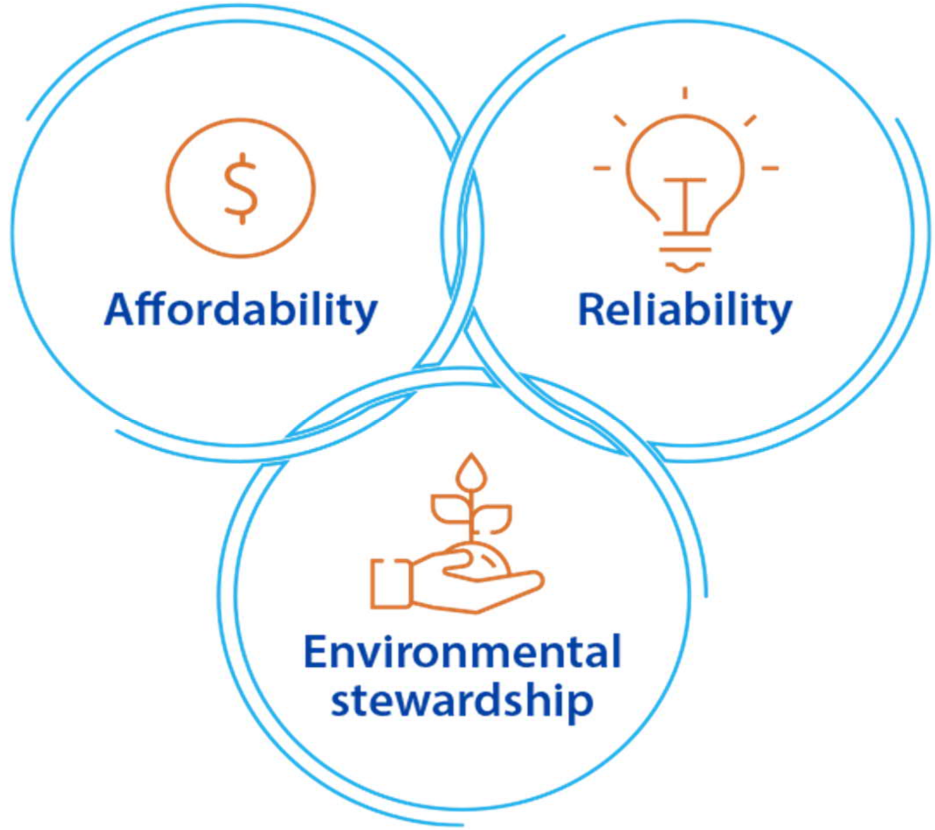
Purpose

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

Key Objectives

- Sustainable portfolios are built with **lowest reasonable 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

- 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

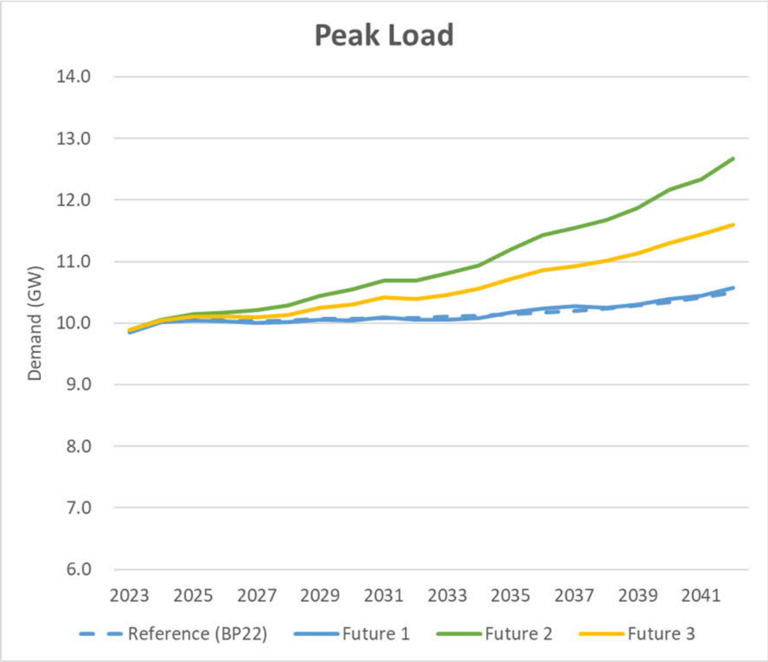
Assessment of Resource Need

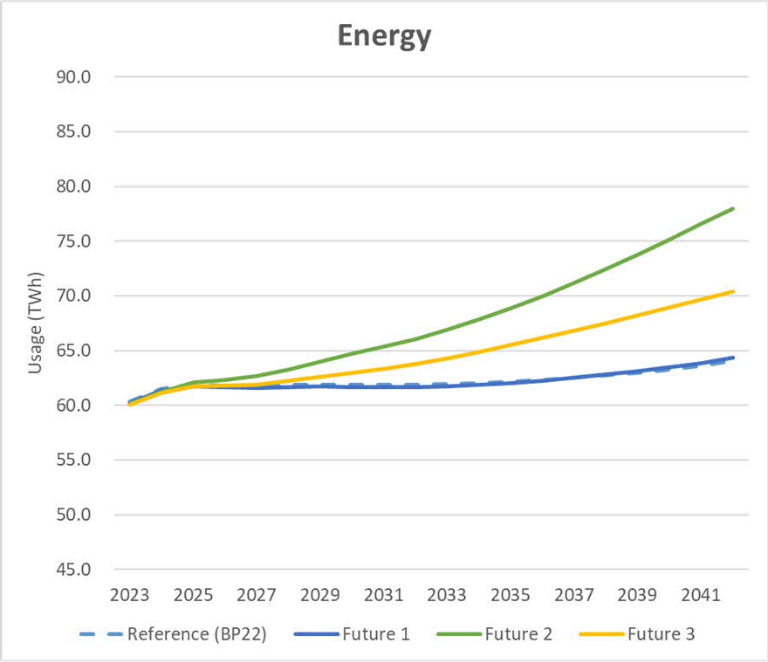
Load Levers for IRP Futures

- The IRP analysis will rely on 3 futures to assess supply portfolios across a range of market outcomes
- Each future's load levels will be built based on the levers below

	Future 1	Future 2	Future 3
Peak Load & Energy Growth	• BP22	• Highest	• Between Reference and Highest
Behind-the-Meter Solar	• ICF Reference	• ICF High Solar + Batteries	• ICF High Solar + Reference Batteries
Electric Vehicles (EV)	• Reference EV (2055)	• Highest EV (2045 Passenger and Commercial Fleet)	• High EV (2045 Passenger EV)
OpCo DSM	• BP22	• ICF High DSM	• ICF Reference DSM
Res & Com Customer Count Growth	• BP22	• High Growth	• Between Reference and High
Refinery Utilization Due to EVs	• BP22	• Lowest	• Between Reference and Lowest
Industrial Growth	• BP22	• High	• Between Reference and High
Narrative	• Future 1 aligns with ELL's Reference Case Business Plan ("BP22") • Uses ICF's Reference case solar forecast instead of the BP22 solar forecast	• Future 2 is a high growth scenario driven by growth in all customer classes, the main driver being transportation electrification and industrial growth related to process electrification. • This growth is partially offset by increased behind-the-meter solar adoption and increases in energy efficiency.	• Future 3 is a growth scenario driven by passenger vehicle electrification and industrial growth related to process electrification. • This growth is partially offset by increased behind-the-meter solar adoption and increases in energy efficiency.

ELL IRP Futures Load Forecasts





10-Year CAGR ('23-32)	
Peak (MW) - Reference	0.2%
Peak (MW) – Future 1	0.2%
Peak (MW) – Future 2	0.9%
Peak (MW) – Future 3	0.6%
Energy (GWH) – Reference	0.3%
Energy (GWH) – Future 1	0.3%
Energy (GWH) – Future 2	1.0%
Energy (GWH) – Future 3	0.7%

	2023	2028	2033	2038
Peak (MW) - Reference	9,874	10,050	10,103	10,235
Peak (MW) – Future 1	9,847	10,011	10,063	10,252
Peak (MW) – Future 2	9,890	10,283	10,806	11,671
Peak (MW) – Future 3	9,884	10,138	10,455	11,010
Energy (GWH) – Reference	60,331	61,856	61,927	62,732
Energy (GWH) – Future 1	60,196	61,674	61,747	62,802
Energy (GWH) – Future 2	60,124	63,292	66,878	72,439
Energy (GWH) – Future 3	60,082	62,233	64,297	67,495

All values include Transmission and Distribution losses

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

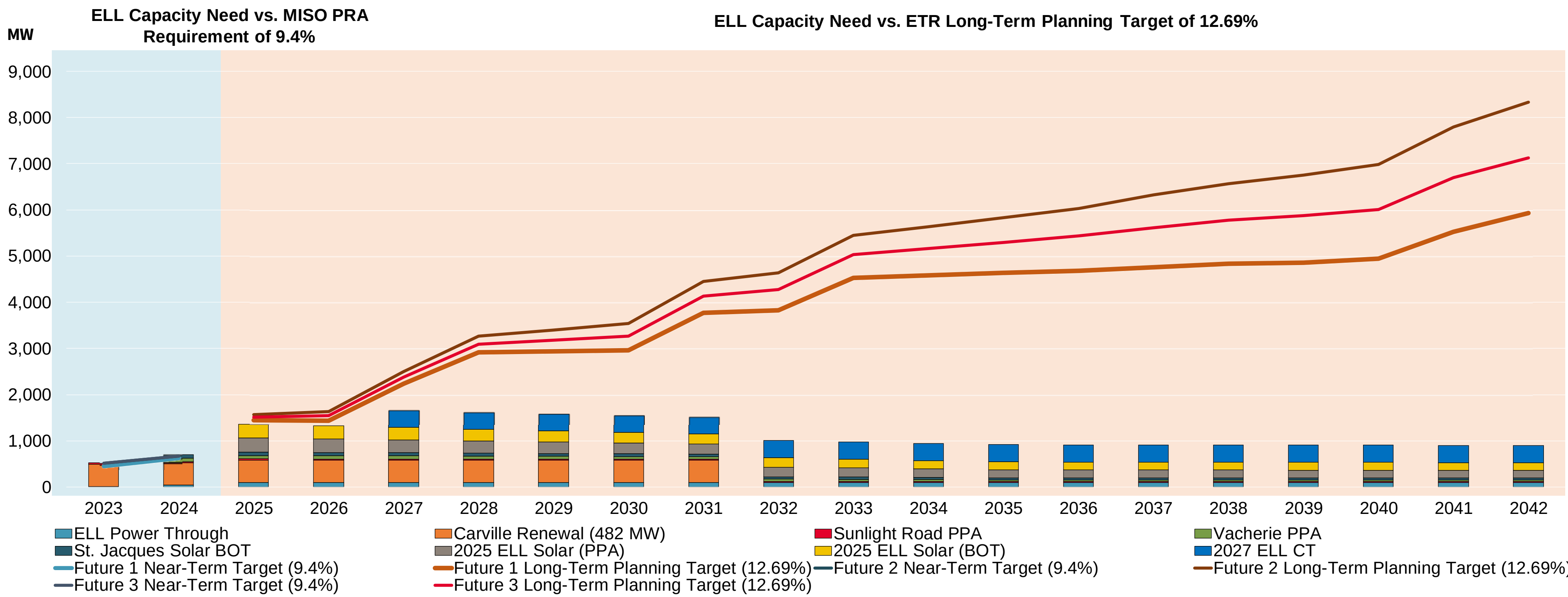
- MWH attributed to electric vehicle charging in the reference case forecast is expected to add 0.5% to ELL's load by 2032, growing to 3.4% by 2042

- 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 Futures 2 and 3 use a 2045 Passenger EV adoption curve (compared to 2055 for reference). Future 2 also includes Commercial Fleet Electrification which is not included in Reference or Future 3.

ELL EV Demand Additions (GWh)			
	Reference	Future 2	Future 3
2023	29	46	44
2024	39	66	64
2025	51	95	91
2026	66	135	129
2027	85	191	180
2028	110	267	248
2029	142	372	341
2030	183	516	463
2031	235	705	618
2032	301	951	808
2033	382	1,267	1,034
2034	481	1,666	1,296
2035	602	2,146	1,589
2036	746	2,711	1,911
2037	914	3,355	2,254
2038	1,110	4,065	2,987
2039	1,333	4,825	2,987
2040	1,585	5,603	3,367
2041	1,861	6,391	3,749
2042	2,164	7,170	4,120

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
Future 1 Surplus/ (Deficit)	61	75	(91)	(120)	(575)	(1,289)	(1,345)	(1,397)	(2,244)	(2,818)	(3,545)	(3,631)	(3,717)	(3,770)	(3,846)	(3,926)	(3,946)	(4,044)	(4,619)	(5,032)
Future 2 Surplus/ (Deficit)	0	24	(217)	(307)	(836)	(1,636)	(1,801)	(1,981)	(2,918)	(3,624)	(4,463)	(4,682)	(4,912)	(5,118)	(5,408)	(5,656)	(5,842)	(6,077)	(6,885)	(7,429)
Future 3 Surplus/ (Deficit)	8	34	(164)	(222)	(713)	(1,468)	(1,583)	(1,708)	(2,610)	(3,266)	(4,054)	(4,213)	(4,373)	(4,518)	(4,704)	(4,866)	(4,970)	(5,103)	(5,793)	(6,229)

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

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Capability Needs Future 1 Assumptions

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
ELL Future 1 Load																				
MISO Coincident Peak	9,917	10,081	10,090	10,084	10,080	10,086	10,105	10,114	10,124	10,152	10,149	10,176	10,223	10,267	10,331	10,378	10,393	10,464	10,547	10,629
Transmission Losses (1.80%)	179	181	182	182	181	182	182	182	182	183	183	183	184	185	186	187	187	188	190	191
Adjusted Load	10,095	10,262	10,272	10,266	10,261	10,268	10,287	10,296	10,307	10,334	10,331	10,359	10,407	10,452	10,517	10,565	10,580	10,653	10,736	10,820
Reserve Margin Percentage	9.38%	9.38%	12.69%	12.69%	12.69%	12.69%	12.69%	12.69%	12.69%	12.69%	12.69%	12.69%	12.69%	12.69%	12.69%	12.69%	12.69%	12.69%	12.69%	12.69%
Reserve Margin	947	963	1,303	1,303	1,302	1,303	1,305	1,307	1,308	1,311	1,311	1,315	1,321	1,326	1,335	1,341	1,343	1,352	1,362	1,373
Total Load Requirement	**11,042**	**11,225**	**11,575**	**11,569**	**11,563**	**11,571**	**11,592**	**11,603**	**11,614**	**11,646**	**11,643**	**11,674**	**11,727**	**11,778**	**11,851**	**11,905**	**11,923**	**12,004**	**12,099**	**12,193**
ELL Resources (UCAP)																				
Owned Resources + Affliate PPAs	**9,639**	**9,762**	**9,639**	**9,622**	**9,180**	**8,963**	**8,947**	**8,924**	**8,240**	**8,225**	**7,520**	**7,483**	**7,467**	**7,466**	**7,465**	**7,440**	**7,439**	**7,438**	**6,958**	**6,640**
Third Party PPAs	**1,171**	**1,246**	**1,545**	**1,526**	**1,507**	**1,017**	**999**	**981**	**830**	**303**	**277**	**259**	**242**	**241**	**239**	**238**	**237**	**222**	**221**	**220**
LMRs	**294**	**292**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**	**301**
Total 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
Surplus/(Deficit)	61	75	(91)	(120)	(575)	(1,289)	(1,345)	(1,397)	(2,244)	(2,818)	(3,545)	(3,631)	(3,717)	(3,770)	(3,846)	(3,926)	(3,946)	(4,044)	(4,619)	(5,032)

Notes:

1. This is reflected on a MISO planning year basis which starts 6/1 and ends 5/31 of the following year.
2. Resources will remain the same for all Futures. Load will be adjusted based on Future. This slide is for visibility into Resource Type. Please reference slide 10 for a view across all Futures.

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*	Riverbend 70	389	Owned Resource/ Affiliate PPA*
Arkansas Nuclear One 1*	22		Roy Nelson 6	211	
Arkansas Nuclear One 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	
J. Wayne Leonard Power Station	912		White Bluff 1*	13	
Lake Charles Power Station	913		White Bluff 2*	12	
Little Gypsy 2	405		WPEC	370	
Little Gypsy 3	504		Agrilectric	9	Third Party PPA
Ninemile 4	724		Carville	243	
Ninemile 5	728		Capital Region Solar	50	
Ninemile 6	438		Oxy-Taft	471	
Ouachita 3	241		Rain CII	28	
Perryville 1	355		Toledo Bend	48	
Perryville 2	101		Vidalia	133	
Riverbend 30	191		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.
- 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. As a result, 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
Sterlington	7a	2022
[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

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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

	Future 1	Future 2	Future 3
Peak Load & Energy Growth	• Reference	• Highest	• Between Reference and Highest
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

Analytic Process to Create and Value Portfolios

Development of Planning Scenarios and Strategies

Development of assumptions and inputs for Futures

Market Modeling

Projection of MISO market <u>outside of ELL</u> for each Future

Portfolio Development

Construction of resource portfolios for each Future

Total Relevant Supply Cost

Production costs and fixed costs are determined for each portfolio under each Future

Risk Assessment

Assessment of each portfolio to measure potential risk

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 total relevant present value of fixed and variable costs to customers

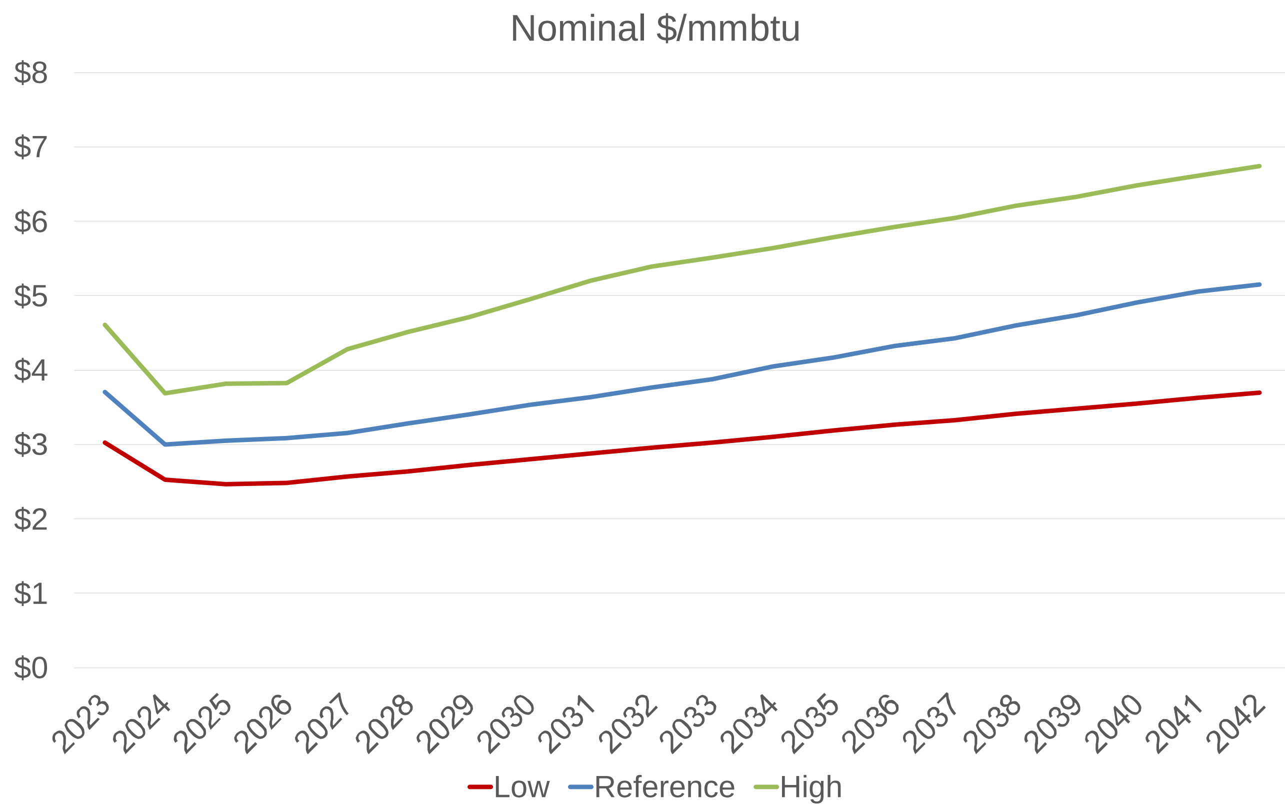
ILLUSTRATIVE ONLY—Actual number of Scenario/Portfolio combinations is TBD

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

Modeling Assumptions

Gas Price Forecast



Forecasting Methodology

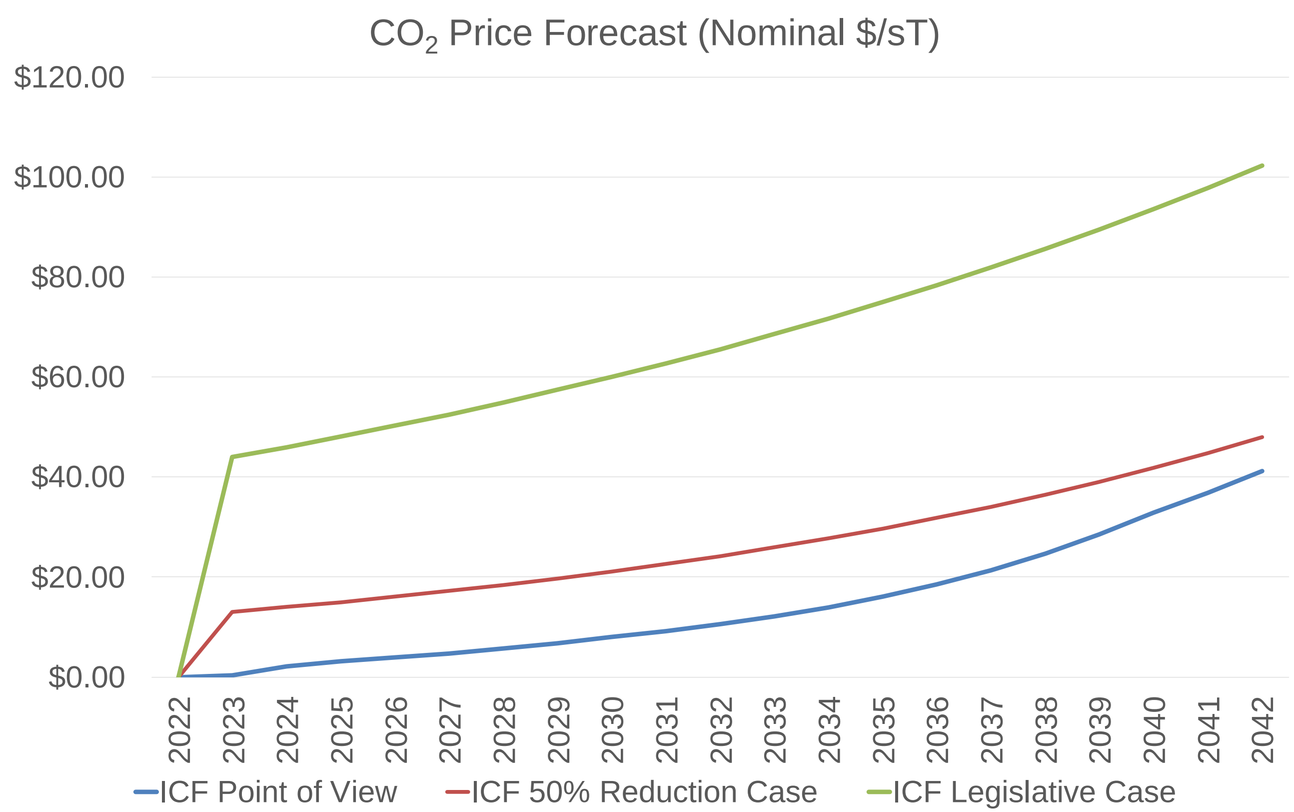
Reference case

- 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

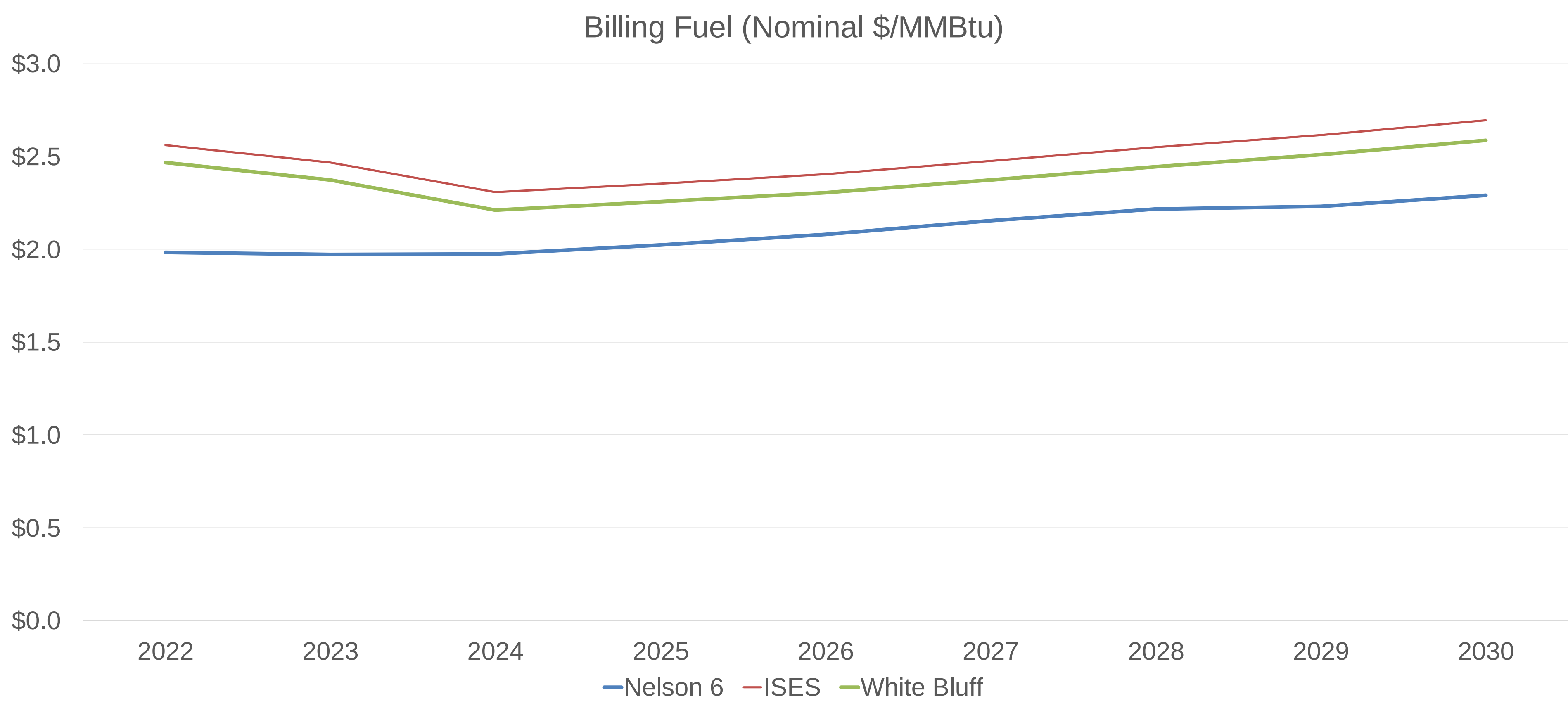
CO2 Price Forecast



Forecasting Methodology

- The ICF Legislative Case is based on the Climate Leadership Council's Carbon Dividend proposal.
- The ICF 50% Reduction Case is representative of price needed to reach national target of 50% reduction from 2020 levels by 2050
- 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.

Coal Price Forecast



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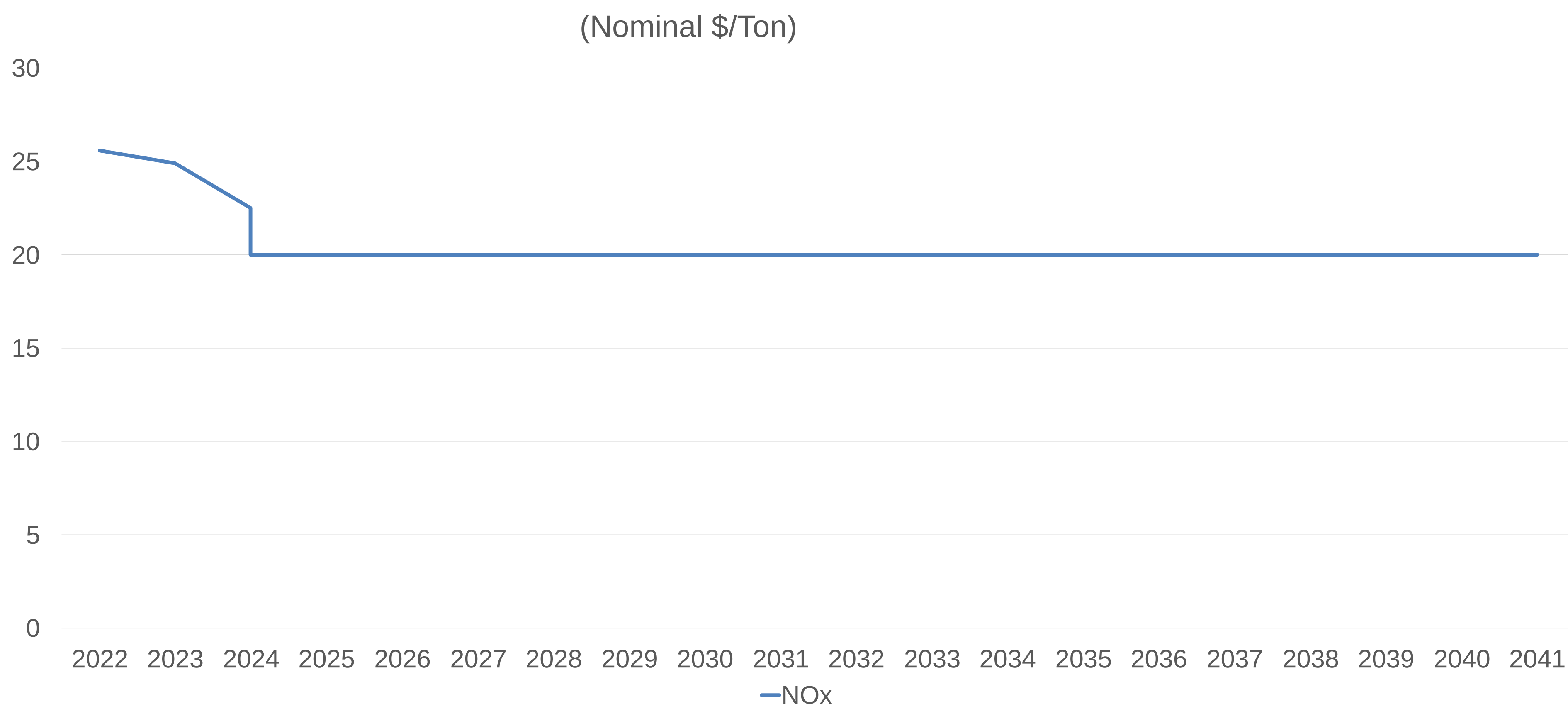
NO_x Price Forecast



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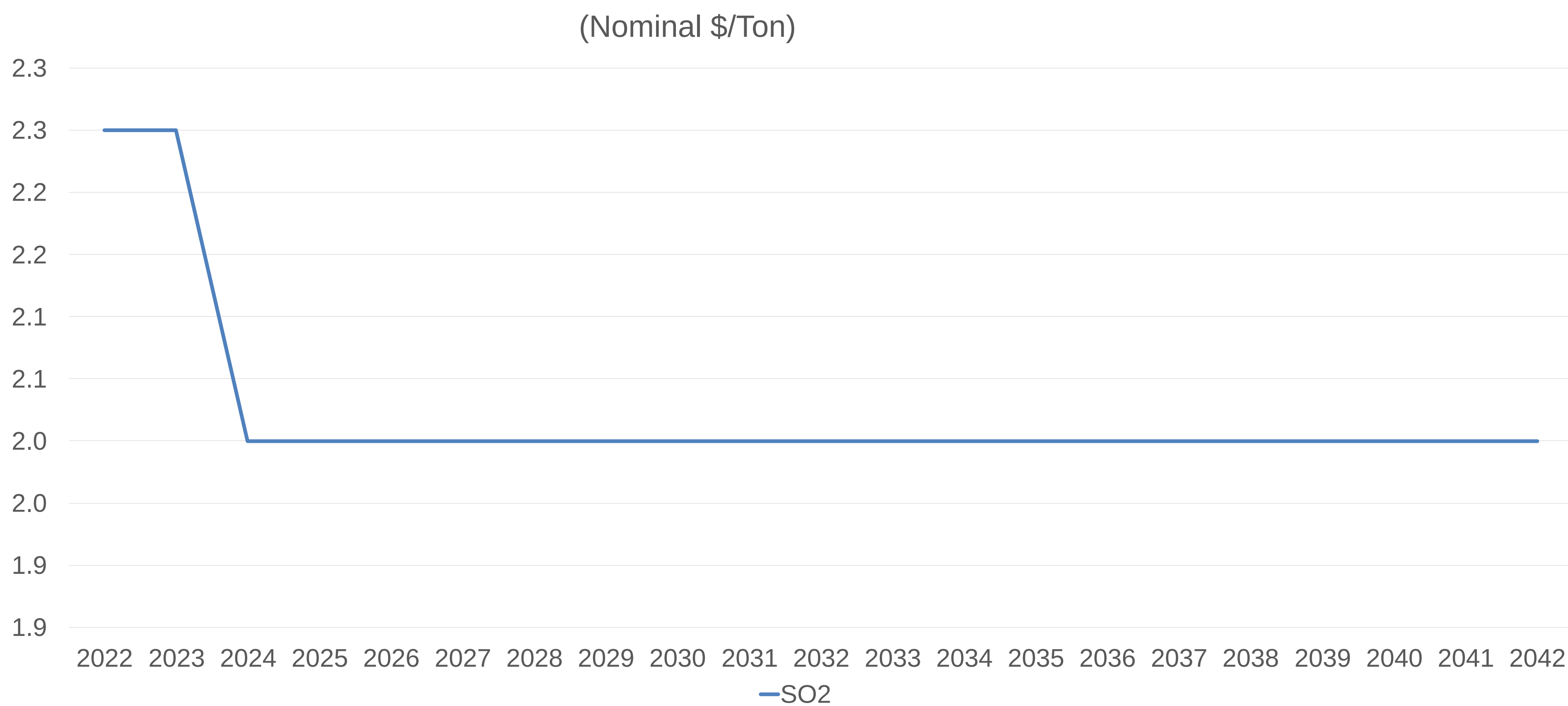
SO_2 Price Forecast



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Capacity Value Forecast

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Inflation Forecast and Financial Assumptions

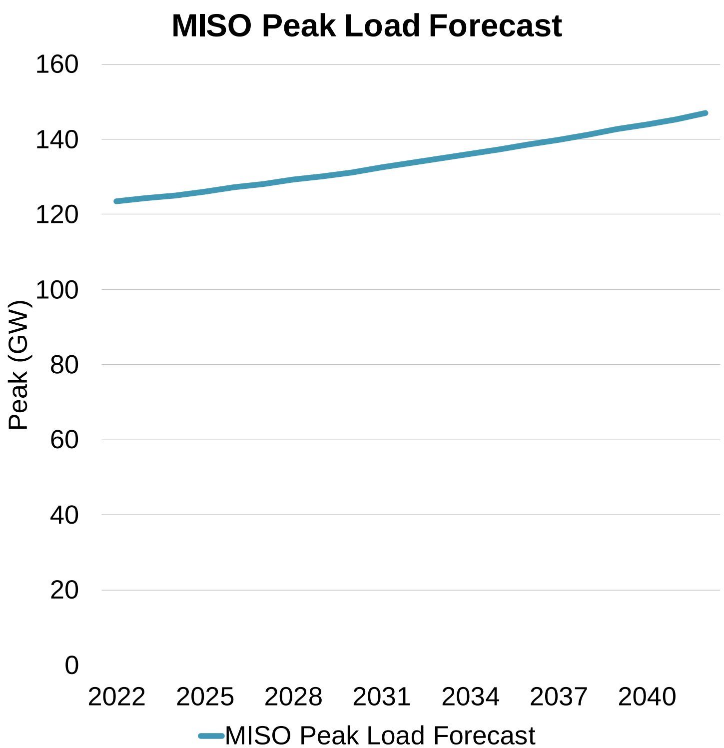
2021 EPG GDP POV	
	Inflation Rate
2023	2.25%
2024	2.00%
2025	2.00%
2026	2.00%
2027	2.00%
2028	2.00%
2029	2.00%
2030	2.00%
2031	2.00%
2032	2.00%
2033	2.00%
2034	2.00%
2035	2.00%
2036	2.00%
2037	2.00%
2038	2.00%
2039	2.00%
2040	2.00%
2041	2.00%
2042	2.00%

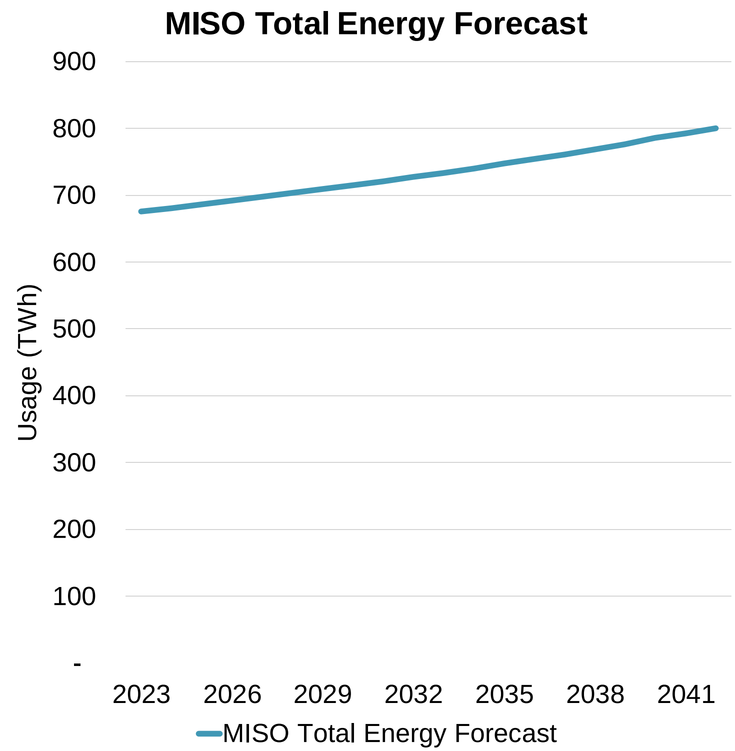
- ELL's WACC is used to assess present value for all potential resource additions to ELL's portfolio

	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

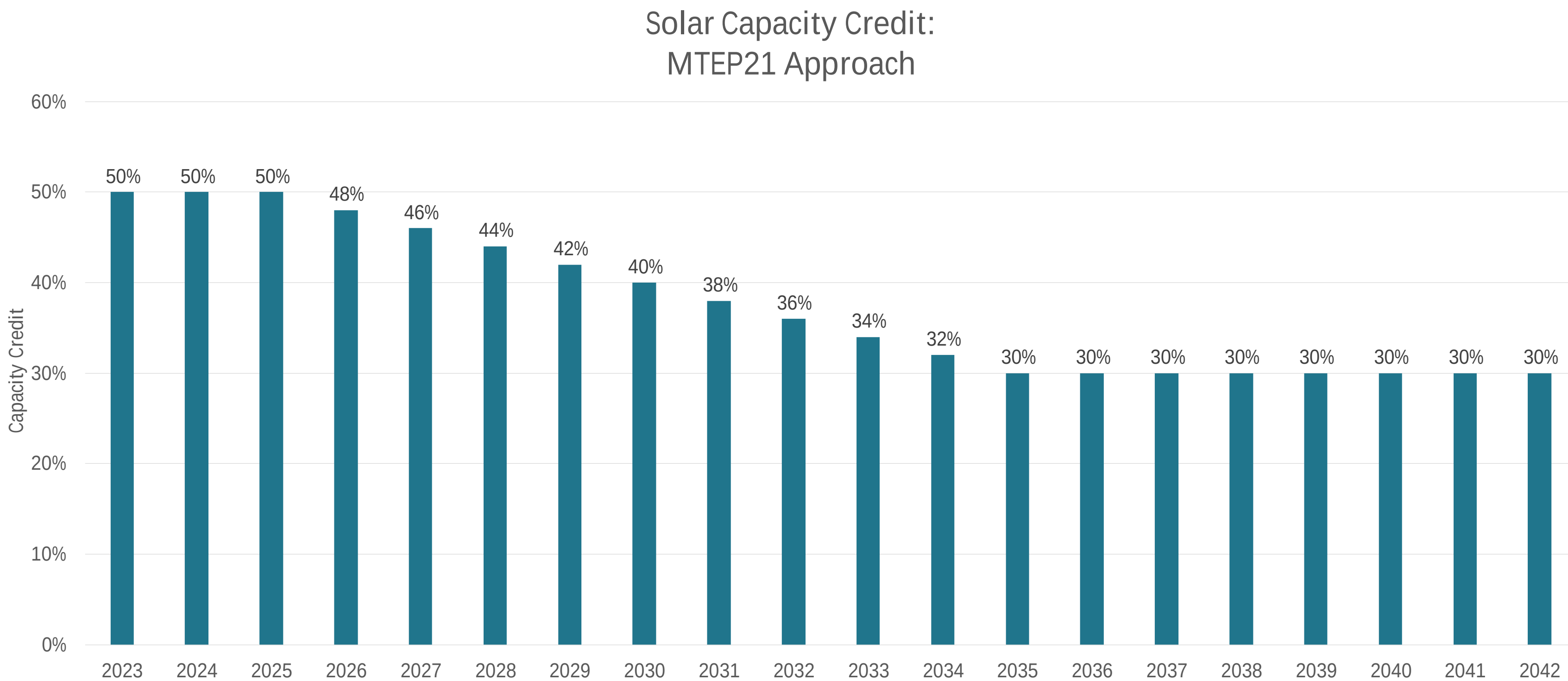




Reference Forecast	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Peak (GW)	124	125	126	127	128	129	130	131	133	134	135	136	137	139	140	141	143	144	145	147
Energy (TWh)	676	681	686	692	697	703	709	715	721	727	733	740	747	754	761	769	776	786	793	801

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.



Renewable Resource Locational Assumptions

ELL 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
- Located in MISO Local Resource Zone 9

Non-ELL MISO Market Assumptions:

- 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

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

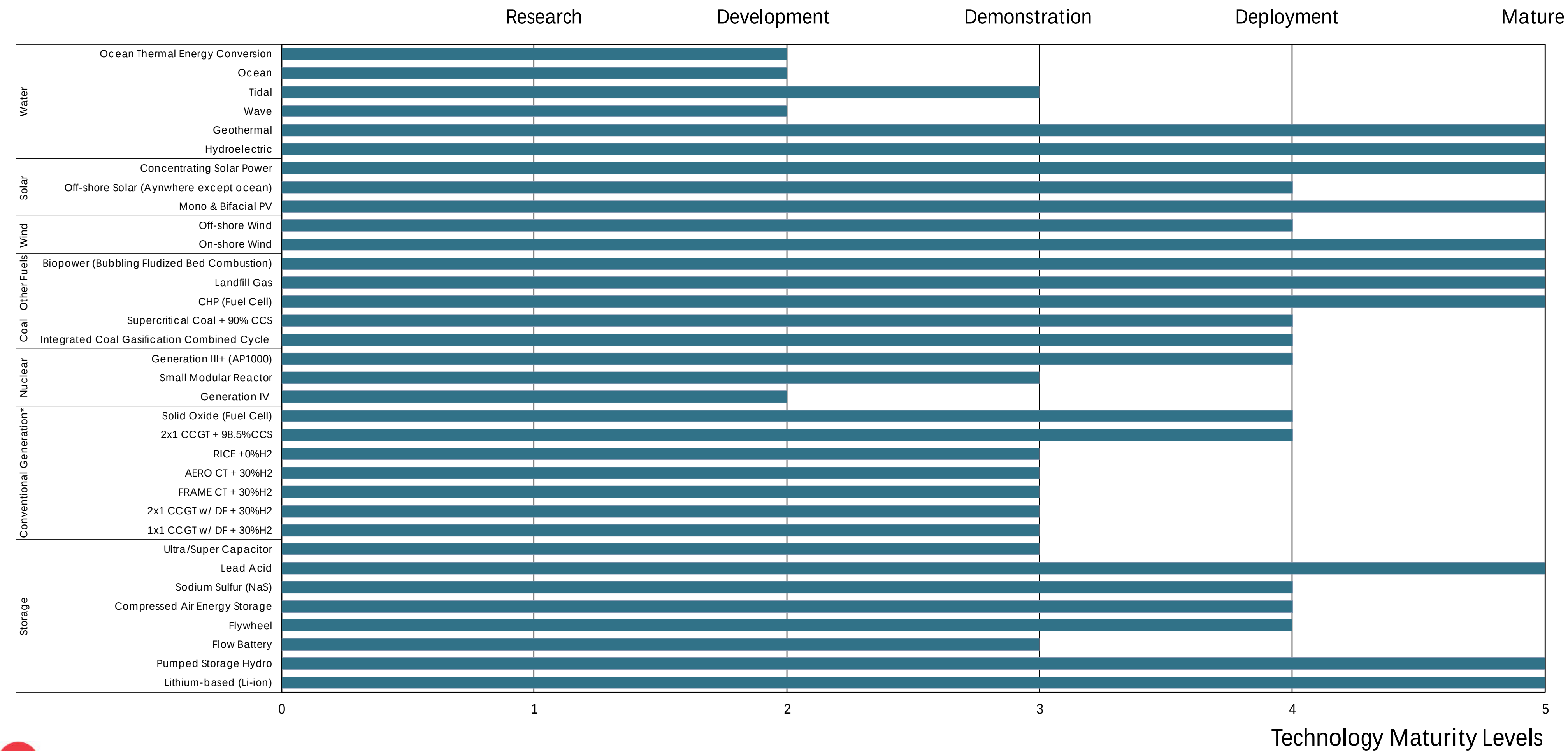
- IRP cost inputs reflect:
  - A generic property tax and insurance assumption of 1.5%
  - A general inflation rate of 2.0%

- 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.

Supply Alternatives

Technology Maturity of Supply Side Resources



Technology Retained for Capacity Expansion

MISO Market Build			Summer Capacity [ICAP MW]
Unit	Configuration	H2 Capability	
CT	M501JAC	30%	365
CCGT	M501JAC (2x1 w/o Duct Firing)	30%	1,055
Solar	Single Axis Tracking	N/A	100
Wind	On-shore Wind	N/A	200
Wind	Off-shore Wind, Fixed	N/A	600
Hybrid	Solar + Battery Hybrid	N/A	100 MW/50 MW
Battery	Lithium-Ion Battery	N/A	50 MW/ 200MWh

ELL Portfolio Evaluation			Summer Capacity [MW]
Unit	Configuration	H2 Capability	
CT	M501JAC	30%	365
CCGT	M501JAC (1x1 w/o Duct Firing)	30%	525
CCGT	M501JAC (2x1 w/o Duct Firing)	30%	1,055
Aero-CT	LMS100PA	30%	100
RICE	Wartsila 18V50SG (7x)	0%	129
Solar	Single Axis Tracking	N/A	100
Wind	On-shore Wind	N/A	200
Wind	Off-shore Wind, Fixed	N/A	600
Hybrid	Solar + Battery Hybrid	N/A	100 MW/50 MW
Battery	Lithium-Ion Battery	N/A	50 MW/ 200MWh

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Gas + Hydrogen Resource Assumptions

Technology			Summer Capacity [MW] [1]	Capital Cost [Nominal, 2022$/kW] [2, 3]	Fixed O&M [Levelized R., 2022$/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	$925	$6.66	$14.74	9,165	2.00%	4.50%
CCGT	M501JAC (1x1 w/o Duct Firing)	30%	525	$1,156[4]	$18.43	$3.47	6,375	2.50%	5.50%
CCGT	M501JAC (2x1 w/o Duct Firing)	30%	1,055	$894	$12.07	$3.48	6,355	2.50%	5.50%
Aero-CT	LMS100PA	30%	100	$1,438[5]	$6.47	$3.21	9,015	0.80%	2.90%
RICE	Wartsila 18V50SG (7x)	0%	129	$1,688[6]	$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 AERO CT (see note 5) and RICE units (see note 6).
3. Hydrogen Capable resource costs will only apply to ELL owned resources. Market resources will not include costs associated with Hydrogen capability.
4. Capital cost assumes that an SCR will be used for NOx emission control.
5. As of date, hydrogen capability has been demonstrated. Cost impacts of hydrogen firing capability are not fully vetted by the industry and therefore excluded.
6. As of date, hydrogen capability is planned but not yet demonstrated. Costs or performance impacts of hydrogen firing capability is therefore excluded.

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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]	26.75%
DC:AC	1.23
Hourly Profile Modeling Software	PVSyst

ITC Assumptions[4,5]

	ITC
2023	30%
2024-2025	26%
2026[6]	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 Fixed O&M excludes property tax and insurance; Solar includes inverter replacement in year 16.
3. Capacity Factor based on MISO South region.
4. ITC Benefit normalized over asset useful life.
5. ITC –eligible portion assumed to be 90% of total capital cost.
6. ITC assumed 10% in 2026 and thereafter.

Source:

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Wind Assumptions

Installed Cost Projections [1]

On-shore Wind		Off-shore Wind, Fixed	
Year	Nominal ($/kW)[2]	Year	Nominal ($/kW)[3]
2023	$1,505	2023	$3,620
2024	$1,503	2024	$3,477
2025	$1,510	2025	$3,346
2026	$1,526	2026	$3,227
2027	$1,545	2027	$3,116
2028	$1,566	2028	$3,011
2029	$1,587	2029	$2,912
2030	$1,608	2030	$2,818
2031	$1,629	2031	$2,768
2032	$1,652	2032	$2,722
2033	$1,676	2033	$2,679
2034	$1,700	2034	$2,638
2035	$1,725	2035	$2,600
2036	$1,749	2036	$2,564
2037	$1,774	2037	$2,529
2038	$1,801	2038	$2,496
2039	$1,828	2039	$2,465
2040	$1,855	2040	$2,436
2041	$1,883	2041	$2,407
2042	$1,913	2042	$2,380

Notes:
1. Installed cost projections do not include transmission costs.
2. First-year determined by averaging five sources. Future years determined by aligning with projected technology cost curve from IHS.
3. Based on Wind Resource Class 6, moderate scenario, calculated as nominal values with 2% inflation factor.
4. Wind Fixed O&M excludes property tax and insurance.
5. Capacity Factor based on MISO South (On-shore Wind) and Gulf of Mexico (Off-shore Wind, Fixed) region.

Source:
ON-SHORE WIND | IHS MARKIT (12.19), LAZARD (10.20), EPRI (12.20), EIA (07.21), NREL ATB (2020)
OFF-SHORE WIND | NREL ATB (2021)

Other Modeling Assumptions

	On-shore Wind	Off-shore Wind, Fixed
Size (MW)	200MW	600MW
Fixed O&M (Levelized R. 2022$/KWac-yr) [4]	$37.72	$76.95
Useful Life (yr)	30	25
MACRS Depreciation (yr)	5	5
Capacity Factor [5]	36.8%	38.3%
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%

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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

Notes:

1. BESS Installed Capital Cost includes 10% initial oversizing in year 1 to account for Depth of Discharge (DoD), followed by replacement of 10% of battery modules every five years (year 6, 11, & 16) to allow for a 20-year life.
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.

Source:

Solar Battery Hybrid Resource Assumptions

Installed Cost Projections[1]

Utility-scale Solar Battery Hybrid	
Year	Nominal ($/kW)
2023	$1,612
2024	$1,571
2025	$1,524
2026	$1,488
2027	$1,468
2028	$1,460
2029	$1,457
2030	$1,455
2031	$1,450
2032	$1,449
2033	$1,450
2034	$1,451
2035	$1,455
2036	$1,460
2037	$1,467
2038	$1,475
2039	$1,482
2040	$1,490
2041	$1,502
2042	$1,514

Other Modeling Assumptions

	Hybrid
Size (MW)	100 MW Solar 50 MW/ 200 MWh Battery
Fixed O&M (Levelized R. 2022$/KWac-yr)[2]	$10.52
Useful Life (yr)	30-year Solar 20-year Battery
Capacity Factor [3]	25.6%
DC:AC	1.25
Hourly Profile Modeling Software	Vibrant Clean Energy

ITC Assumptions

	ITC
2023	30%
2024-2025	26%
2026[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 Fixed O&M excludes property tax and insurance; Solar includes inverter replacement in year 16
3. BESS Installed Capital Cost includes 10% initial oversizing in year 1 to account for Depth of Discharge (DoD), followed by replacement of 10% of battery modules every five years (year 6, 11, & 16) to allow for a 20-year life.
4. Capacity Factor based on MISO South region.
5. ITC assumed 10% in 2026 and thereafter.
6. ITC Benefit normalized over asset useful life.
7. ITC –eligible portion assumed to be 90% of total capital cost.

Source:

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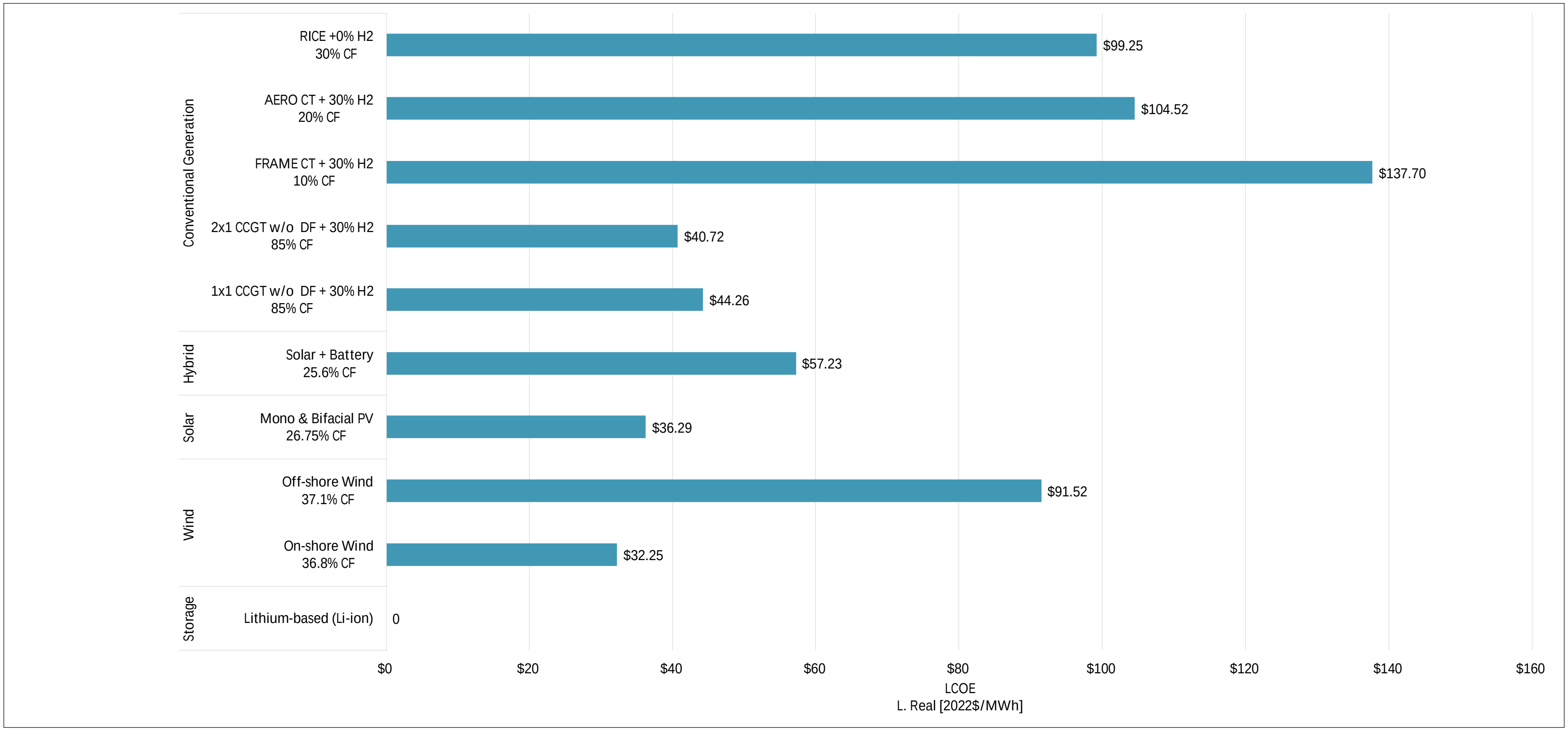
Assumptions: Levelized Cost of Electricity



- Based on a 2023 COD resource.
- LCOE is calculated as levelized total cost over the book life divided by the levelized energy output over the book life.
- LCOE for storage is not shown because as storage just moves MWh from one time to another there is no actual 'output' of energy therefore it's undefined.
- Solar resources include an additional $10M per 100MWs for interconnection costs.
- Offshore wind values do not include costs for transmission.
- Capacity factor (“CF”)

Methodology: Levelized Cost of Electricity:

- LCOE calculates the revenue required to build and operate a generator over a specified cost recovery period and the revenue available to that generator over the same period. In other words, it allows the comparison of different technologies (e.g., wind, solar, natural gas, etc.,) of unequal life spans, project size, different capital cost, risk, return, and capacities. LCOE is often cited as a convenient summary measure of the overall completeness of different generating technologies. However, it is important to note that LCOE does not capture all the factors that contribute to actual investment decisions.
- Key inputs to calculating LCOE include installed capital cost, fixed o&m cost, variable o&m cost (emissions & fuel cost), applicable subsidies (ITC & PTC factored in the revenue requirement calculation) and revenue requirement (tax & discount rate), and assumptions regarding energy production, capacity factor, useful life, and efficiency.
- Following below is a simple way of showing the calculation method of LCOE.

$$\frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

I_t = Investment expenditures in year t (including financing)
M_t = Operations and maintenance expenditures in year t
F_t = Fuel expenditures in year t
E_t = Electricity generation in year t
r = Discount rate
n = Life of the system

Source: Department of Energy (2015)

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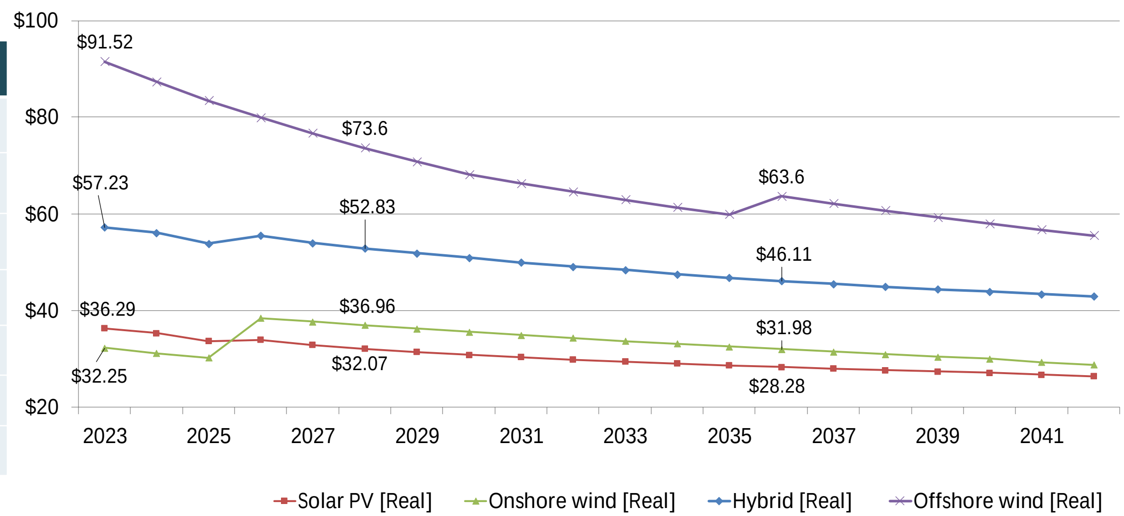
Assumptions: Renewables LCOE (Solar, Wind & Hybrid – MISO South)

Modeling Assumptions

	Solar	Onshore Wind	Offshore wind	Hybrid
Size (MW)	100MW	200MW	600MW	100 MW Solar 50 MW Battery
Fixed O&M (Levelized R. 2022$/KWac-yr) [1]	$10.52	$37.72	$76.95	$10.52 Solar $10.71 Battery
Useful Life (yr)	30	30	25	30-year Solar 20-year Battery
MACRS Depreciation (yr)	5	5	5	5-year Solar 7-year Battery
Capacity Factor	26.75%	36.8%	38.3%	25.6%
DC:AC	1.23	N/A	N/A	1.25
Hourly Profile Modeling Software	PVSyst 7	NREL SAM	NREL SAM	AURORA

LCOE (Levelized Real in 2022$/MWh) [2,3,4,5]



Notes:

1. Solar and Wind Fixed O&M excludes property tax and insurance; Solar includes inverter replacement in year 16.
2. LCOE is calculated as levelized total cost over the book life divided by the levelized energy output over the book life. (based on 9.2021 ELL WACC)
3. ITC normalized over useful life and assumes an extended ITC for Solar, PTC for On-shore Wind, and ITC for Off-shore Wind.
   Assumes solar projects online in 2023 receive 30% ITC. Assumes solar projects online between 2024 and 2025 receive 26% ITC. Solar projects online beginning 2026 and beyond receive 10% ITC.
   Assumes on-shore wind projects online between 2023 and 2025 receive 60% PTC. On-shore wind projects online in 2026 or beyond are not eligible for tax credits.
4. Solar resources include an additional $10M per 100MWs for interconnection costs.
5. Offshore wind values do not include costs for transmission.

Source:

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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	January 27, 2022	✓
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	-

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