Entergy

ENO 2018 IRP
Technical Meeting #2

UPDATED

September 14, 2018

WE POWER LIFE℠

Goals and Agenda of Technical Meeting #2

Goals

- As described in the Initiating Resolution (R-17-430), the main purpose of this meeting is for ENO, the Advisors, and Intervenors to attempt to reach consensus on the Scenarios and Strategies that were initially discussed in Technical Meeting #1 (and which have been refined as described in this presentation), **<u>or</u>**
- To discuss the Planning Scenario and/or Strategies that have been prepared by the Intervenors and provided to the parties in advance of this Technical Meeting

Agenda

1. Analytical Framework and Portfolio Development
2. ENO Capacity Need and Supply Alternatives
3. IRP Inputs and Assumptions
4. Timeline and Next Steps

Technical Meeting #1—Follow Ups

- **Proposed Planning Scenarios**
  - Add narrative descriptions
  - Consider impact of 50/50 renewables-to-gas buildout on LMPs
  - Consider CO_2 pricing adjustments to create better range of macro market futures
- **Proposed Planning Strategies**
  - Propose ideas for Strategy 3 for group discussion, possible consensus building, per IRP Rules, Sec. 7 (D)2
- **IRP Modeling**
  - Further discussion of portfolio development process
- **Inputs Workbook**
  - Produce workbook with relevant IRP modeling inputs
  - Transition from BP18U to BP19

Section 1
Analytical Framework and Portfolio Development

Analytic Process to Create and Value Portfolios

Development of Planning Scenarios and Strategies

Development of assumptions and inputs for Scenarios and Strategies

Market Modeling

Projection of MISO market **<u>outside of ENO</u>** for each Scenario

Portfolio Development

Construction of resource portfolios for each Scenario/Strategy combination

Total Relevant Supply Cost

Production costs and fixed costs are determined for each portfolio under each Scenario/Strategy combination

Action Plan

Identify action plan that balances reliability, cost, and risk

Proposed Scenario Purpose and Drivers

IRP analytics rely on macro market Scenarios designed to allow for the assessment of the total production cost and risk of resource portfolios across a reasonable range of possible future outcomes. The three proposed Scenarios for the ENO 2018 IRP are:

Scenarios	Key Drivers
Scenario 1 (Moderate Change Over Time)	• Flat/declining usage per customer (UPC) in residential and commercial sectors due to increases in energy efficiency and other customer adopted measures • UPC declines partially offset by industrial growth and growth in residential and commercial customer counts • Renewables and gas replace retiring capacity to promote fuel diversity in long-term resource planning
Scenario 2 (Customer Driven Change)	• Low peak load growth and natural gas prices tied to slumping demand • Growth rate of residential and commercial demand and energy usage decreased due to strong customer preferences for EE and DERs • Capacity additions in the MISO market are weighted towards gas-fired generation due to low gas and CO_2 prices
Scenario 3 (Policy Driven Change)	• Growth rate of residential and commercial customer demand and energy usage increased through economic development and moderated energy efficiency gains • Political and economic pressure on coal and legacy gas plants accelerates retirements • High CO_2 pricing along with economic factors drive the replacement of retiring capacity with portfolio of equal amounts of renewables complemented with battery storage and gas-fired technology to replace retiring capacity

Development of ENO Proposed Planning Scenarios – Update

MISO Market Outside of New Orleans

- Aurora market model testing has shown negative Locational Marginal Prices (LMPs), over an extended period of time as a result of the 50/50 renewables-to-gas market additions originally proposed for the MISO market
  - These negative LMPs could result in the suppression of renewable resource additions in portfolios designed for ENO
  - Because it is not realistic to expect the MISO market to experience negative LMPs over an extended period of time, it was necessary to reconsider this assumption

- Based on this testing, two of the three Scenarios proposed at Technical Meeting #1 were modified as shown on following slide:
  - To mitigate the impact that negative LMPs would have on the results and to encourage a range of market prices, ENO:
    - Adjusted the second Scenario to reflect a 25%/75% renewables-to-gas mix for MISO Market additions, and adjusted the CO_2 pricing assumption
    - Adjusted the third Scenario to incorporate battery deployment to address the possibility of negative LMPs due to the 50/50 renewables-to-gas addition assumption
- This helps ensure that the market model doesn't preclude any resource type because of negative LMPs

ENO Proposed Planning Scenarios – Assumptions

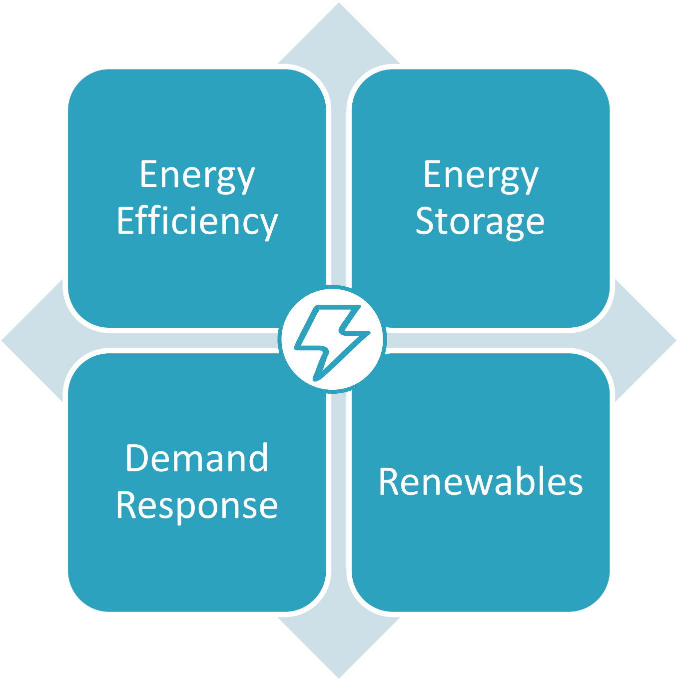
	Scenario 1 (Moderate Change)	Scenario 2 (Customer Driven)	Scenario 3 (Policy Driven)
Peak Load & Energy Growth	Medium	Low	High
Natural Gas Prices	Medium	Low	High
Market Coal & Legacy Gas Deactivations	60 years	55 years *(Modified from 50 years)*	50 years *(Modified from 55 years)*
Magnitude of Coal & Legacy Gas Deactivations[2]	12% by 2028 54% by 2038	31% by 2028 88% by 2038	54% by 2028 91% by 2038
MISO Market Additions Renewables / Gas Mix	34% / 66%	25% / 75% *(Modified from 50%/50%)*	50% / 50%
CO_2 Price Forecast	Medium	Low *(Modified from High)*	High *(Modified from Medium)*

1. Highlighted cells indicate a change since Technical Meeting #1
2. "Magnitude of Coal & Legacy Gas Deactivation" driven by "Market Coal and Legacy Gas deactivation" assumptions (e.g. 55 Years; 31%/88%) and were likewise swapped between Scenarios 2 and 3. Percentages based on BP18U for MISO South; to be adjusted for BP19

ENO Proposed Planning Strategies– Update

Proposed Strategy 3: Renewables, Storage, and DSM Alternative

- **Policy-driven, and possible consensus/reference, strategy under which incremental capacity needs are exclusively met through a diverse array of renewables, battery storage, and DSM**



WE POWER LIFE℠

ENO Proposed Planning Strategies--Assumptions

	Strategy 1[1]	Strategy 2[2]	Strategy 3[3]
Objective	Least Cost Planning	0.2/2% DSM Goal	Renewables, Storage & DSM Alternatives
Capacity Portfolio Criteria and Constraints	Meet 12% Long-term Planning Reserve Margin (PRM) target using least-cost resource portfolio	Include a portfolio of DSM programs that meet the Council's stated 2% goal	Meet peak load need + 12% PRM target using DSM, solar, and battery resources
Description	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on total relevant supply costs	Assess portfolio of DSM programs that meet Council's stated 0.2/2% goal along with consideration of additional supply-side alternatives	Assess demand- and supply-side alternatives to meet projected capacity needs with a focus on adding solar and batteries
DSM Input Case	Navigant Base	Navigant 2%	To be discussed

1 Least Cost Strategy – required by IRP Rules Sec. 7(D)1
2 Policy Goal Strategy – required by IRP Rules Sec. 7(D)3
3 Proposed Consensus/Reference Strategy – required by IRP Rules Sec. 7(D)2

Optimized Portfolio Design

- **Aurora Capacity Expansion Algorithm Portfolios**
  - Used to identify least cost portfolios for each Strategy across a range of Scenarios.

- **Aurora Production Cost Modeling**
  - Select portfolios are later tested across Scenarios in the Aurora Production Cost model in order to calculate the variable supply costs for each portfolio/Scenario combination.

	Benefits	Challenges
Aurora Capacity Expansion	• Capable of finding least cost portfolios given inputs and constraints • 3rd party model-based portfolio development • Considers multiple market and cost inputs • Simultaneously considers multiple competing constraints • Captures intermittent resource attributes • Consistent application of algorithm	• Dependent on and sensitive to changes to inputs in ways that can be unpredictable • May not account for qualitative benefits and considerations • May not account for all stakeholder preferences • Application of constraints without judgment can result in less appropriate resource selection • Lack of transparency for validation and explanation of results

Optimized Portfolio Design

Which Strategy?

Least Cost | 2% DSM | Renewables, Storage, DSM | Stakeholder

Strategy Driver	Least Cost; 2% DSM; Renewables, Storage, DSM; Stakeholder
Design Process	Aurora Capacity Expansion Software
Total Fixed Costs	For each Scenario, Aurora Capacity Expansion creates the least cost portfolio of demand- and supply-side resources to meet the identified need (peak load + 12% PRM)
Total Variable Production Costs	Using Aurora's Production Cost Modeling, select portfolios are analyzed across Scenarios
Total Supply Costs	Total supply costs (fixed + variable production costs) calculated for select portfolios/scenario combinations for comparison and analysis
Sensitivity Analysis	Least cost portfolios subjected to sensitivity analysis to examine effects of differing fuel prices, CO2 costs, etc.

Optimized Portfolio Design *Illustrative*

	Strategy 1 Least Cost	Strategy 2 2% DSM	Strategy 3 Renewables, Storage, DSM	Strategy 4 (Stakeholder)
Scenario 1	Portfolio	Portfolio	Portfolio	Portfolio
Scenario 2	Portfolio	Portfolio	Portfolio	Portfolio
Scenario 3	Portfolio	Portfolio	Portfolio	Portfolio
Scenario 4 (Stakeholder)	Portfolio	Portfolio	Portfolio	Portfolio

Optimized Portfolio Design *Illustrative*

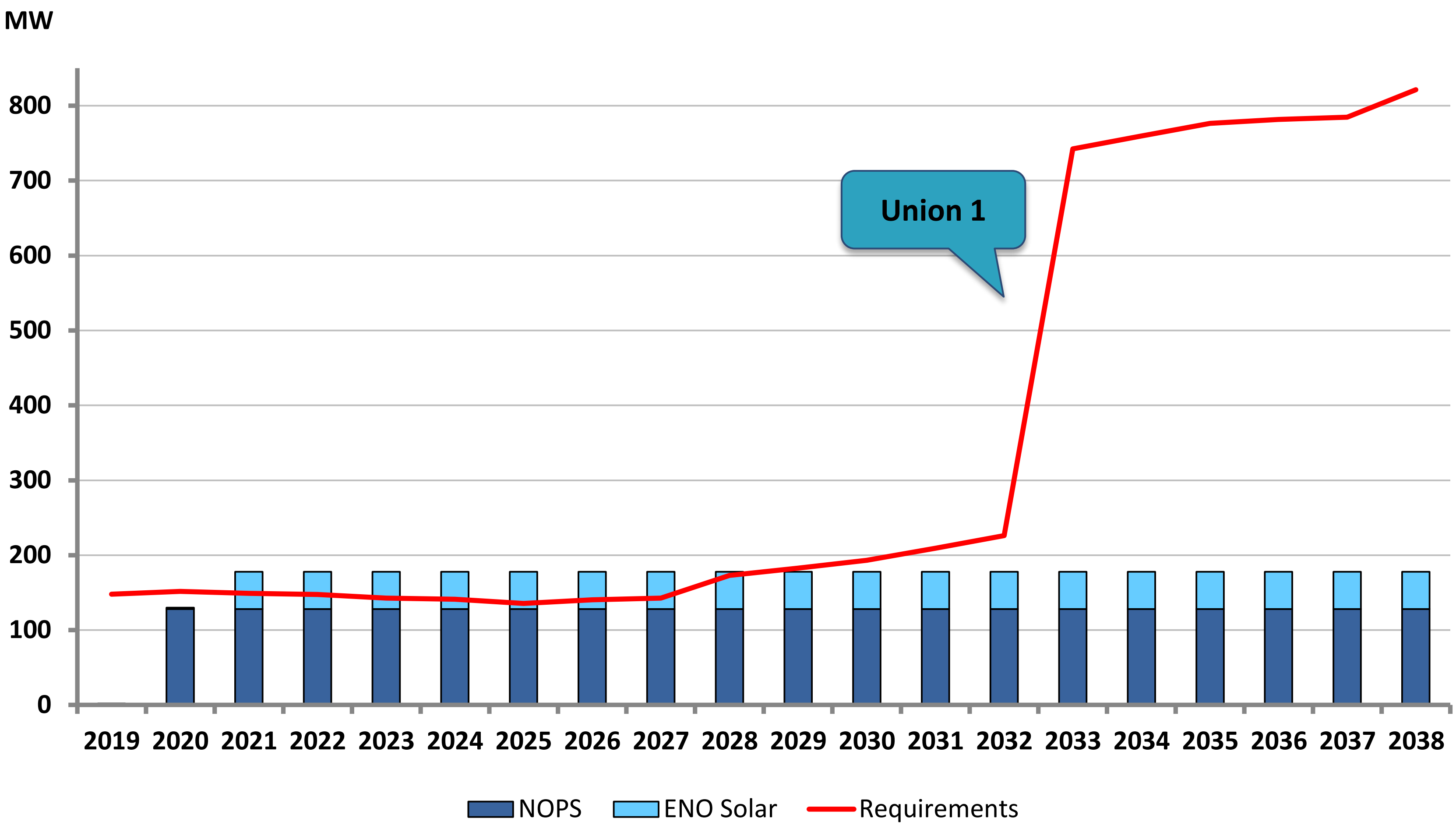
	Strategy 1 Least Cost	Strategy 2 2% DSM	Strategy 3 Renewables, Storage, DSM	Strategy 4 (Stakeholder)
Scenario 1	Portfolio	Portfolio	Portfolio	Portfolio
Scenario 2	Portfolio	Portfolio	Portfolio	Portfolio
Scenario 3	Portfolio	Portfolio	Portfolio	Portfolio
Scenario 4 (Stakeholder)	Portfolio	Portfolio	Portfolio	Portfolio

NOTE: In this example, all 7 of the select portfolios would be tested across the 4 Scenarios in the Production Cost Model, generating 28 Total Relevant Supply Cost Results

Section 2
ENO Capacity Need and Supply Alternatives

ENO's Long-Term Capacity Need

ENO's existing and planned capacity portfolio over the 20 year planning period



Assumptions:

- *Requirements based on non-coincident peak and a 12% reserve margin*
- *ENO Solar additions modeled with 50% effective capacity (100 MW nameplate)*

DSM Resources

- Same process for DSM evaluation as in 2015 IRP; including additional step to enable selection of DSM options that are cost-effective after year 1
- DSM programs will be evaluated based on the characteristics and attributes provided in the potential studies.
  - Demand Response programs described by an average annual load reduction and annual program costs will be evaluated through spreadsheet models outside of the Aurora model based on capacity value net of fixed program costs.
  - Energy Efficiency programs described by an hourly load reduction profile and annual program costs.
- Programs determined to be economic (i.e. positive net benefits) will be selected in the first year.
  - ENO's capacity position (surplus/deficit) will be adjusted to reflect the capacity contribution of selected Demand Response programs.
- Programs not considered economic in year one will be evaluated by AURORA alongside supply side resources in future years (future program inputs to be provided following initial run).
  - DSM programs with hourly load reduction profiles will be evaluated alongside supply side resources in the portfolio design in order to identify the most economic combination of DSM programs and supply side resources.

Supply-Side Technology Resources

- The supply-side technology assessment analyzes potential supply-side generation solutions that could help ENO serve customers’ needs reliably and at the most reasonable cost, including renewables, energy storage, and natural gas technologies.

- ENO’s technology assessment for the 2018 IRP explores in detail the challenges, opportunities, and costs of generation alternatives to be considered when designing resource portfolios to meet the capacity needs of customers.
  - Renewable energy resources, especially solar, have emerged as viable economic alternatives.
  - Trend to smaller, more modular resources (such as battery storage) provides opportunity to reduce risk and manage peak demand.
  - Deployment of intermittent generation has increased the need for flexible, diverse supply alternatives. New smaller scale supply alternatives will better address locational, site specific reliability requirements while continuing to support overall grid reliability.

Renewable Resource Assumptions (Solar PV & Wind)

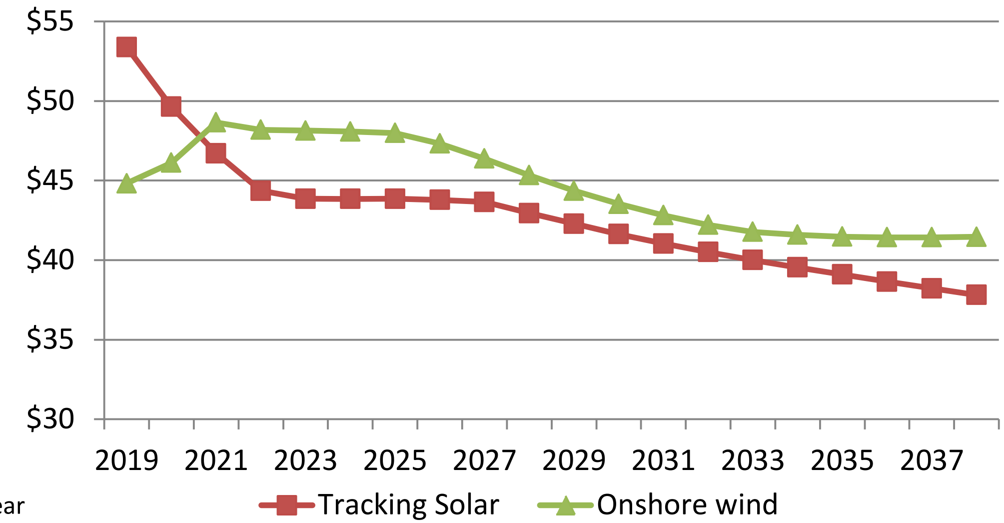
Levelized Real Cost of Electricity (2019$/MWh-AC) [1]

	2019	2020	2021	2022	2023	2026	2029	2032	2035	2038
Solar Tracking [2]	$53.39	$49.64	$46.71	$44.35	$43.86	$43.79	$42.28	$40.51	$39.10	$37.82
Onshore Wind [3]	$44.82	$46.12	$48.65	$48.19	$48.14	$47.32	$44.35	$42.21	$41.47	$41.46

Other Modeling Assumptions

	Solar	Wind
Fixed O&M (2017$/kW-yr-AC)	$16	$36.01
Useful Life (yr)	30	25
MACRS Depreciation (yr)	5	5
Capacity Factor	26%	36%
DC:AC	1.35	N/A
Hourly Profile Modeling Software	PlantPredict	NREL SAM

Levelized Real Cost of Electricity (2019$/MWh) [1]



1. Year 1 levelized real cost for a project beginning in the given year
2. ITC normalized over useful life and steps down to 10% by 2023
3. PTC steps down to 40% by 2020 and expires thereafter

Source: The capital cost assumptions for Wind and Solar are based on a confidential IHS Markit forecast.

Grid-Scale Battery Storage Alternatives

As battery storage technology continues to improve it is important to assess the costs and benefits associated with its deployment to meet long-term needs in the proper context.

Battery storage includes a range of unique attributes that should be considered, such as:

- The ability to store energy for later commitment and dispatch (energy and capacity value)
- Ability to discharge in milliseconds and fast ramping capability (ancillary services)
- Potential deferral of transmission and distribution upgrades
- Rapid construction (on the order of months)
- Modular deployment provides potential scalability
- Portability and capability to be redeployed in different areas
- Small footprint (typically less than an acre), allowing for flexible siting
- Low round-trip losses compared to other storage technologies (such as compressed air)

These attributes should be considered in the appropriate context, not all of which is well understood at this time, including but not limited to:

- Batteries are not a source of electric generation
- Useful life can be much shorter than other grid-scale investments (replacement cost)
- Market rules not yet established to govern participation in wholesale markets
- Discharge less electricity than required to charge due to losses
- Cost of environmentally sound disposal

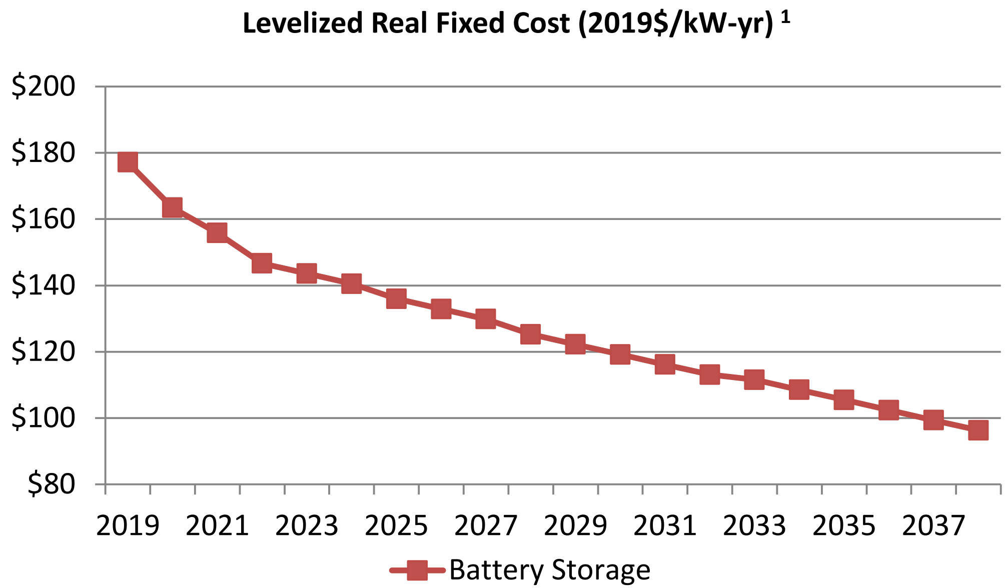
Battery Storage Assumptions

Levelized Real Fixed Cost (2019$/kW-yr) [1]

	2019	2020	2021	2022	2023	2026	2029	2032	2035	2038
Battery Storage	$177	$163	$155	$146	$143	$132	$122	$113	$105	$96

Other Modeling Assumptions

	Battery Storage
Energy Capacity : Power [2]	4:1
Fixed O&M (2017$/kW-yr)	$9.00
Useful Life (yr) [3]	10
MACRS Depreciation (yr)	7
AC-AC efficiency	90%
Hourly Profile Modeling Software	Aurora



1. Year 1 levelized real cost for a project beginning in the given year
2. Current MISO Tariff requirement for capacity credit
3. Assumes daily cycling, no module replacement cost, full depth of discharge

Source: The capital cost assumptions for Battery Storage is based on a confidential IHS Markit forecast.

WE POWER LIFE℠

Gas resource assumptions

Technology		Summer Capacity [MW]	Capital Cost [2017$/kW]	Fixed O&M [2017$/kW-yr]	Variable O&M [2017 $/MWh]	Heat Rate* [Btu/kWh]	Expected Capacity Factor [%]
Combined Cycle Gas Turbine (CCGT)	*1x1 501JAC*	605	$1,244	$16.70	$3.14	6,300	80%
Simple Cycle Combustion Turbine (CT)	*501JAC*	346	$809	$2.37	$13.35	9,400	10%
Aeroderivative Combustion Turbine (Aero CT)	*LMS100PA*	102	$1,543	$5.86	$2.90	9,400	20%
Reciprocating Internal Combustion Engine (RICE)	*7x Wartsila 18V50SG*	128	$1,545	$31.94	$7.30	8,400	30%

*Heat Rate based on full load without duct firing

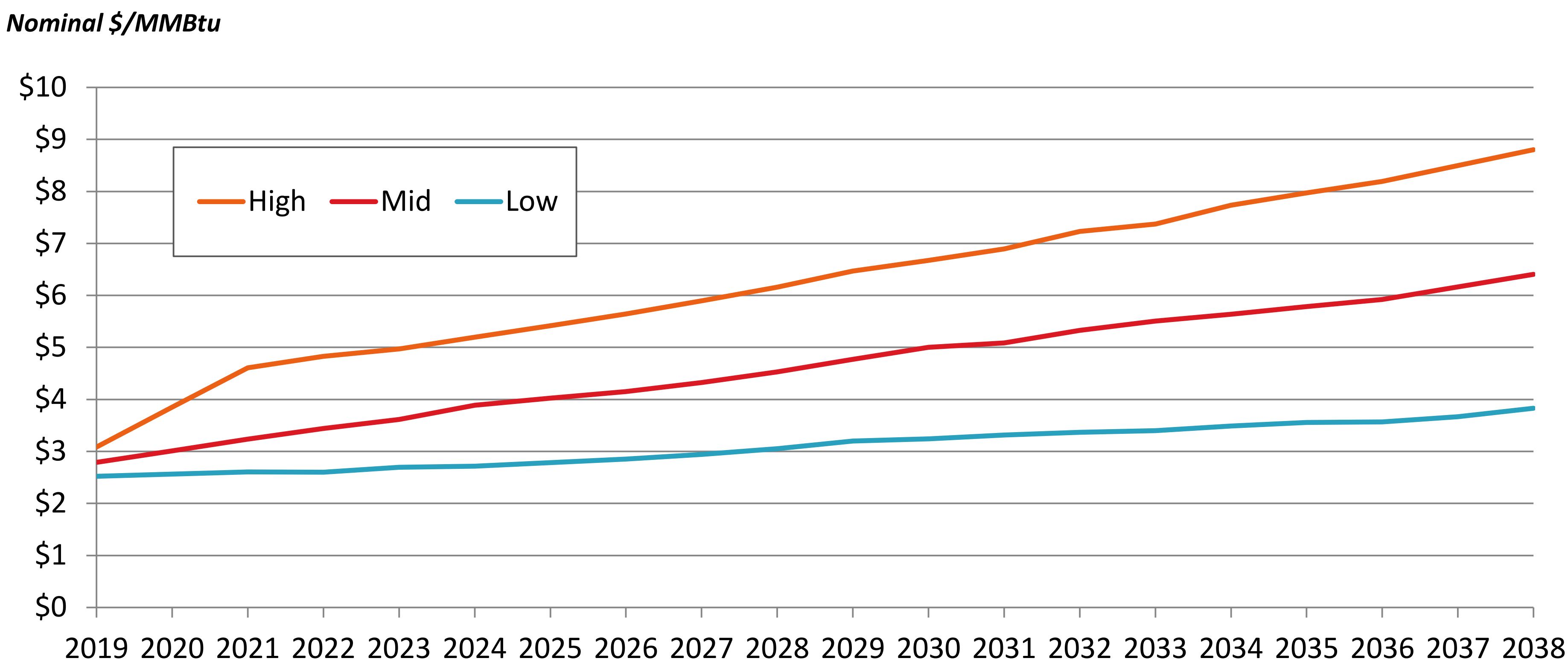
Section 3
Inputs and Assumptions

2018 IRP Inputs and Assumptions

Input/Assumption	MISO Market Modeling	Portfolio Development	Total Relevant Supply Costs
Scenarios & Strategies	✓	✓	✓
Gas Price Forecast*	✓	✓	✓
CO_2 Price Forecast*	✓	✓	✓
Capacity Value*		✓	✓
Supply-Side Resource Alternative Costs*		✓	✓
Load Forecast*	✓	✓	
ENO's Long-Term Capacity Need*		✓	✓
DSM Potential Study Results		✓	✓

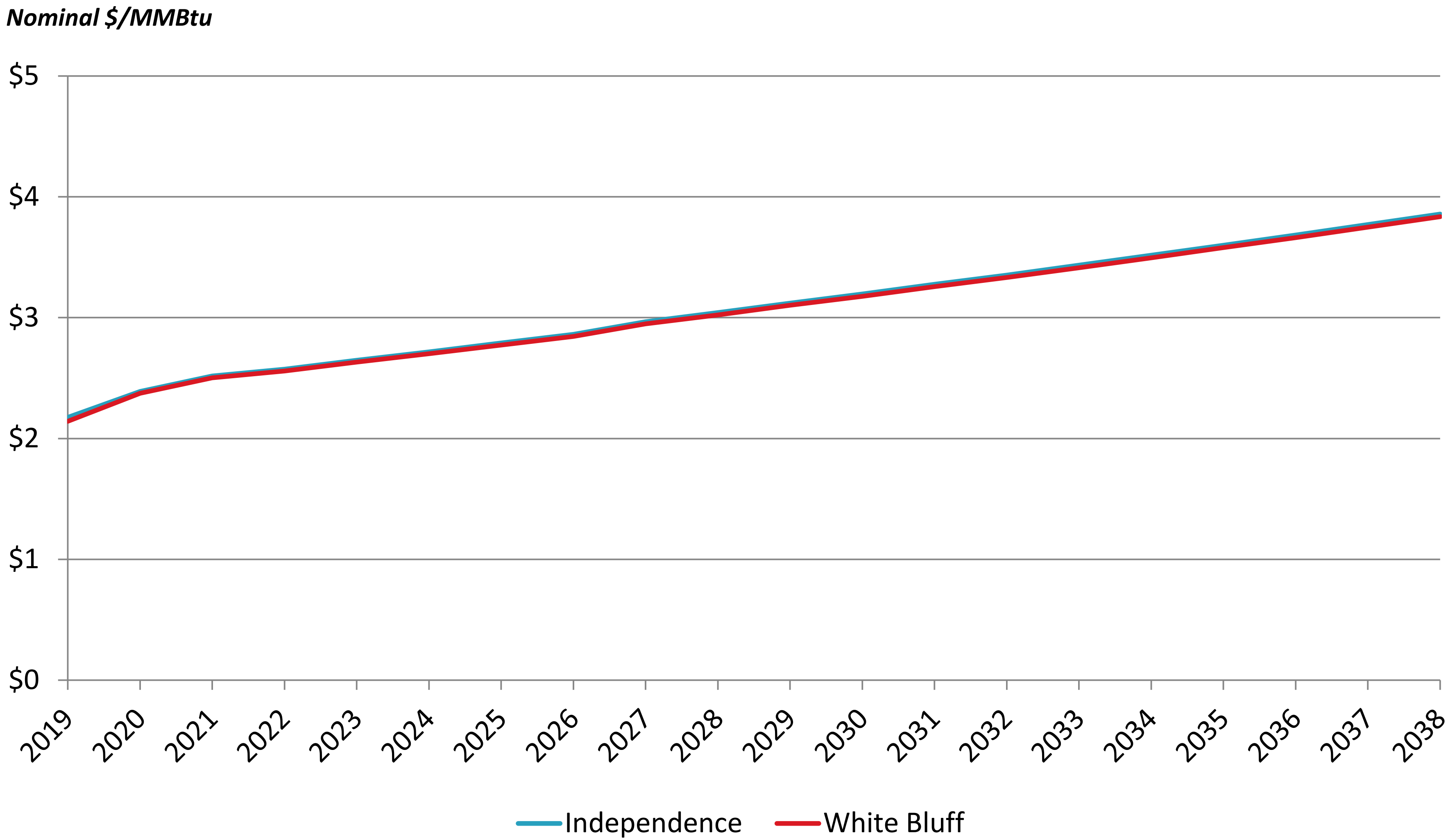
*Updated to Business Plan 19 Inputs since Technical Meeting #1

Gas Price Forecast

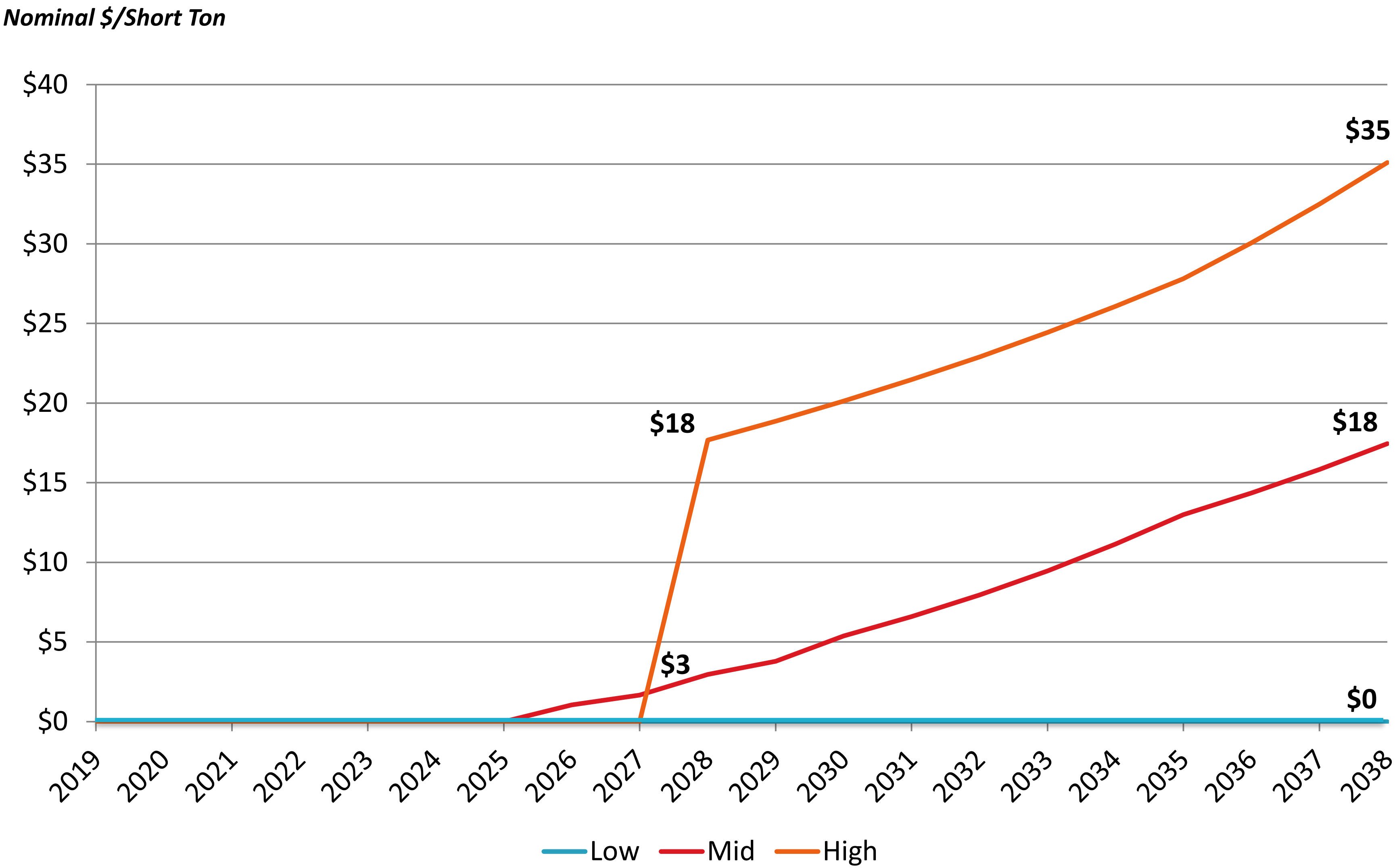


Case	2019	2026	2031	2038
Low	$2.52	$2.86	$3.32	$3.83
Medium	$2.79	$4.15	$5.09	$6.41
High	$3.09	$5.64	$6.89	$8.80

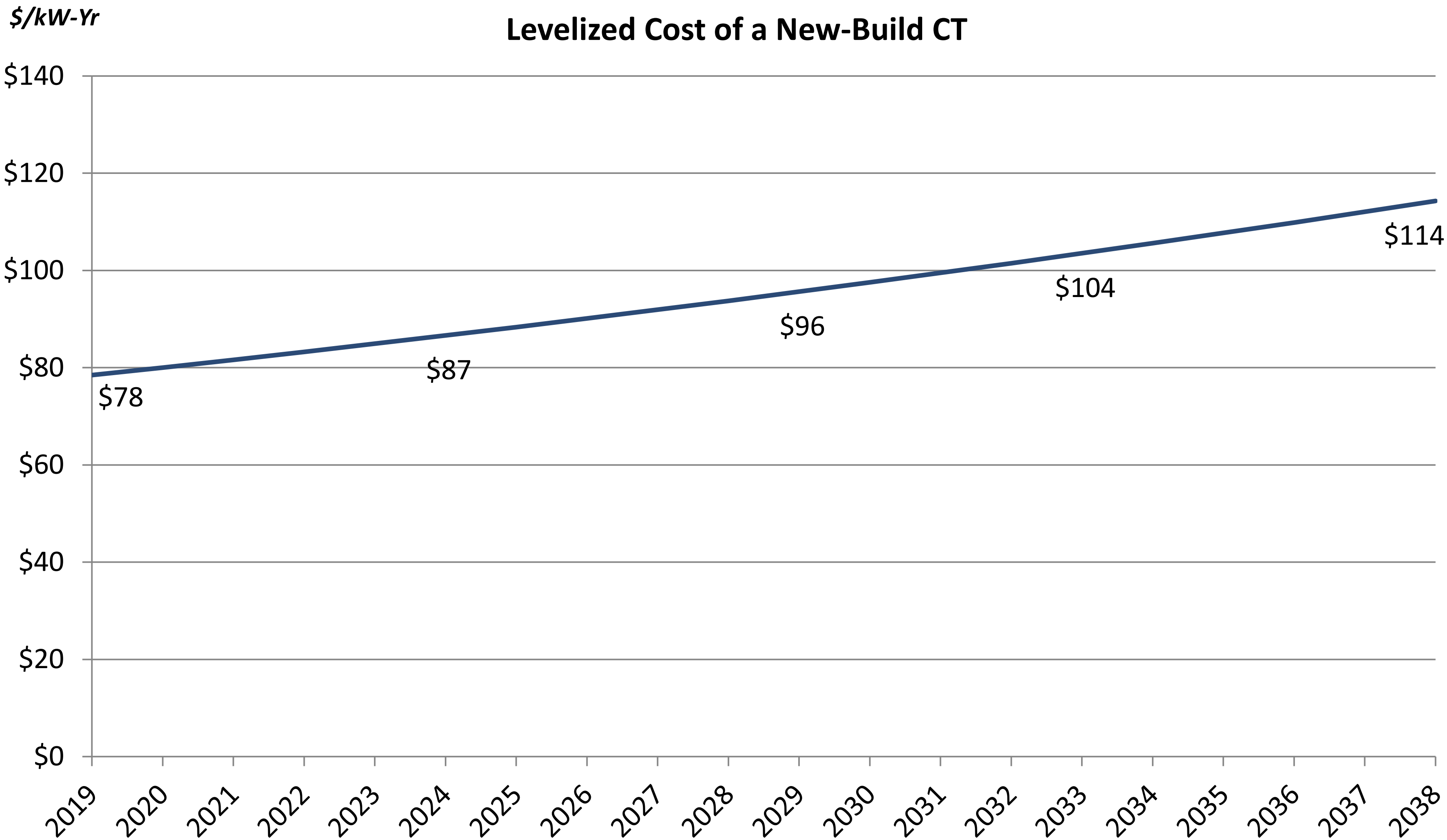
Coal Price Forecast



CO_2 Price Forecast

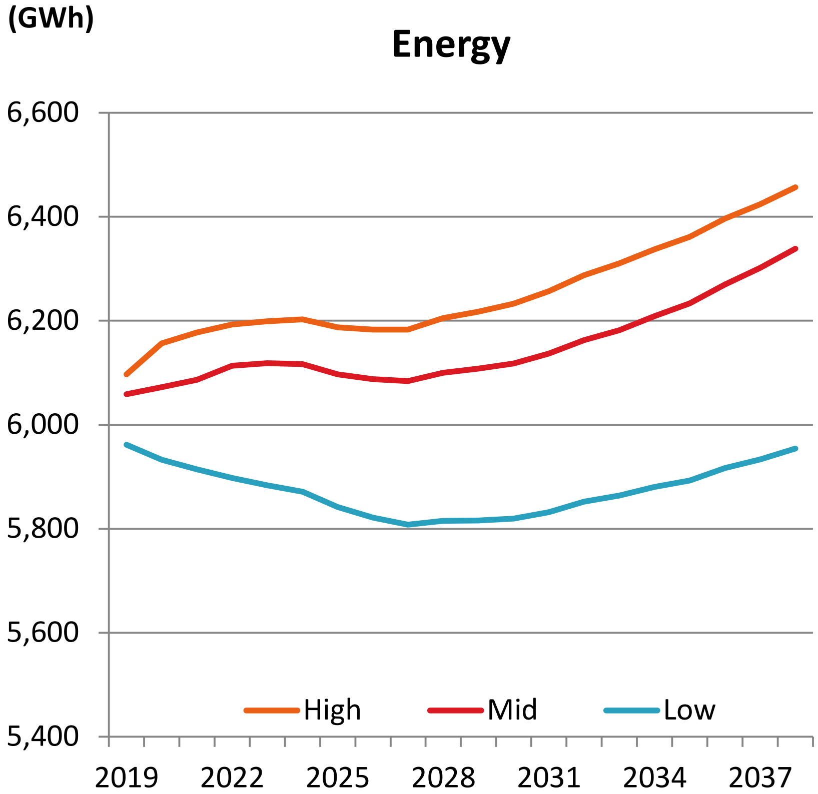


Capacity Value Forecast

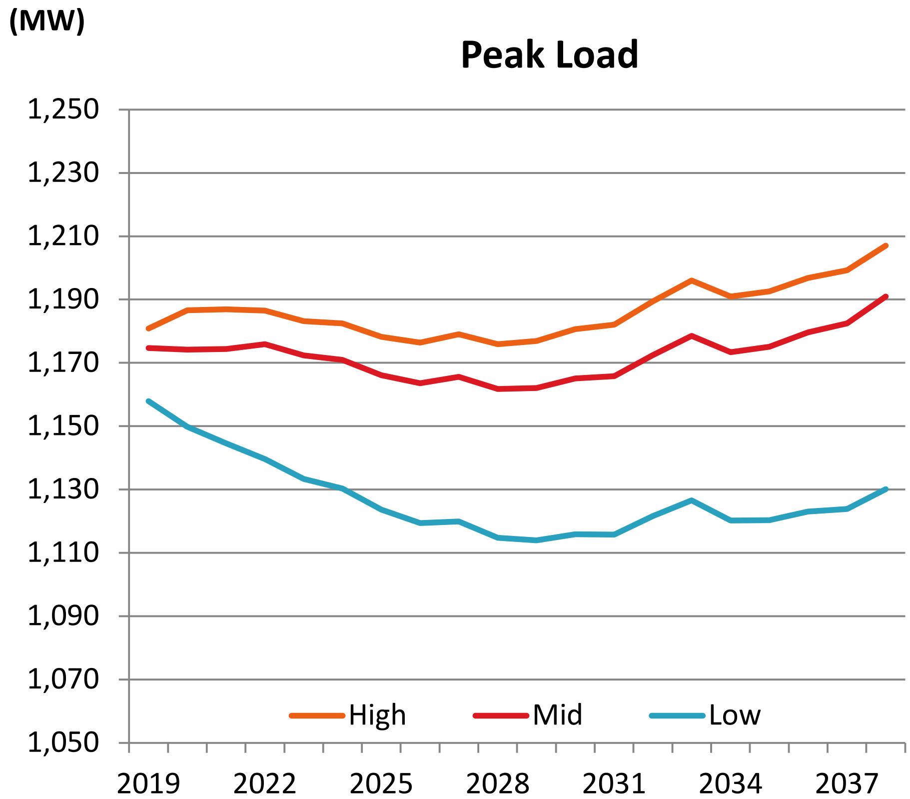


Peak Load & Energy Forecast

3 demand forecasts were created for the ENO IRP: a low, medium, and high



10 Year CAGR (%)	2019 – 2028	2029 – 2038
Low	- 0.28%	0.26%
Medium	0.08%	0.41%
High	0.20%	0.42%



Peak Load (MW)	2019	2024	2029	2033	2038
Low	1,158	1,130	1,114	1,127	1,130
Medium	1,175	1,171	1,162	1,179	1,191
High	1,181	1,182	1,177	1,196	1,207

Section 4
Timeline and Next Steps

Current Timeline

Description	Target Date	Status
Public Meeting #1- Process Overview	September 2017	✓
Technical Meeting #1 Material Due	January 2018	✓
Technical Meeting #1	January 2018	✓
Technical Meeting #2 Material Due	August 2018	✓
Technical Meeting #2	September 2018	✓
Technical Meeting #3 Material Due	November 2018	-
Technical Meeting #3	November 2018	-
IRP Inputs Finalized	**December 2018**	-
Optimized Portfolio Results Due	**April 2019**	-
Technical Meeting #4 Material Due	April 2019	-
Technical Meeting #4	April 2019	-
File IRP Report	July 2019	-
Public Meeting #2 Material Due	July 2019	-
Public Meeting #2 - Present IRP Results	August 2019	-
Public Meeting #3 Material Due	August 2019	-
Technical Meeting #5 Material Due	August 2019	-
Public Meeting #3 - Public Response	September 2019	-
Technical Meeting #5	September 2019	-
Intervenors and Advisors Questions & Comments Due	September 2019	-
ENO Response to Questions and Comments Due	October 2019	-
Advisors File Report	December 2019	-

Appendix

Technical Meeting Purpose

Technical Meeting	Purpose
Technical Meeting 1 (January 22nd)	The purpose of this meeting will be to discuss Planning Scenarios and Strategies. ENO should be prepared to present its Reference (and two alternative) Planning Scenarios, the Least Cost Planning Strategy, and the Utility's proposed Reference Planning Strategy.
Technical Meeting 2 (September 14th)	The purpose of this meeting is to either confirm the consensus Scenario and Strategy or to confirm that ENO is prepared to include the Stakeholder Scenario and Strategy pursuant to the discussions of Technical Meeting 1.
Technical Meeting 3 (November 19th – November 30th)	Purpose is to finalize the Planning Scenarios and Strategies by all parties and lock down of all IRP inputs. The results of the DSM Potential Studies will be provided in the input format required for modeling in the IRP. This meeting will also contain the initial discussion of scorecard metrics.
Technical Meeting 4 (April 22nd – May 3rd)	The purpose of this meeting is to review the Optimized Resource Portfolios, finalize the Scorecard Metrics, and conduct an initial discussion regarding Energy Smart Program budgets and savings goals. For this meeting, ENO should prepare initial proposed Energy Smart Program budgets, and savings goals for discussion.
Technical Meeting 5 (August 28th – September 11th)	The purpose of this meeting is to discuss Energy Smart implementation for Program Years 10-12.