3.23.22 Draft of MIRPP Scenario #2

This scenario aligns with he Miso's December 2021 Futures Report, Future 3. It incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines and assumes that 100% of the utility and state goals are met. This scenario incorporates the retirement announcements and assumptions throughout the MISO footprint, as identified in Future 3. As subsequent Futures Reports are released, updated retirement assumptions identified in the Future most similar to Future 3 of December 2021 Futures Report may be used. Market energy purchases are modeled at a carbon intensity consistent with the relevant RTO system average. MISO expected system averages are identified in Future 3.

This scenario assumes significant advancements toward electrification that drives a total energy and demand growth rates to 1.71% and 1.41% respectively. Emissions decline, driven by state goals and utility plans throughout the MISO footprint, creating at least an 80% carbon reduction by 2040 from the baseline year of 2025 for the MISO region. Assume similar reductions from PJM. This trajectory of carbon reduction is expected to continue beyond 2040. Utilities should use the most recent EIA AEO East North Central Census Region Reference Case[1] for forecasted EV adoption rates with a multiplier of 5 to illustrate significant advancements in EV adoption. Using this information, utilities may develop their own demand and energy forecasts with description and detail how their forecast has included the impacts of climate change[2], electrification, demand side resources, and customer owned distributed generation and how these factors change overall load and demand.

- Natural gas prices utilized are consistent with Reference Case projections from the United States Energy Information Administration's (EIA) most recent annual Energy Outlook.
- Current demand side resources and utility distributed generation programs remain in place and additional growth in those programs would happen if they were economically selected by the model to help comply with the specified carbon reductions in this scenario.
- EV adoption and customer electrification adoption cause adjustments in overall load profiles throughout the planning horizon.
- Non-nuclear, non-coal generators will be retired in the year the age limit is reached and driven by announced retirements. Coal units will primarily be retired based upon carbon emissions and secondarily based upon economics. Nuclear units are assumed to have license renewals granted and remain online.

[1] http://www.eia.gov/outlooks/aeo/tables_ref.php

[2] Midcentury datapoints for several climate change variables are available through Great Lakes Integrated Sciences and Assessments (GLISA) and Center for Climatic Research (CCR) at the University of Wisconsin-Madison. This information should be used to aid in establishing forecasts that include the impacts of climate change.

- Utilities should use the most recent EIA AEO Reference Case[3] for forecasted EV adoption rates. Using this information, utilities may develop their own demand and energy forecasts with description and detail how their forecast has included the impacts of climate change[4], electrification, demand side resources, and customer owned distributed generation and how these factors change overall load and demand.
- Specific new units are modeled if under construction or with regulatory approval (i.e., IRP cost pre-approval, CON, or signed GIA).
- Not less than 35% of the state's electric needs should be met through a combination of EWR and renewable energy by 2025, as per MCL 460.1001 (3).
- The utility can illustrate how the plan is expected to meet state goals for greenhouse gas emissions specific to the power industry sector.
- Existing renewable energy production and storage tax credits and renewable energy investment tax credits continue pursuant to current law. Federal policy timing may impact modeling.
- Long and short duration storage resources are considered. Energy storage resources are modeled using available best practice methodologies to the extent that such guidelines exist. Allow for multiple market revenue streams where applicable.
- Technology costs for wind, solar, storage and other renewables decline with commercial experience and forecasted at levels 30% reduction from scenario 1 by the end of the study period.
- Non-carbon dioxide emitting resources will be increased, due to the constraint on allowable carbon emissions in the model.
- Technology costs and limits to the total resource amount available for EWR and demand response programs will be determined by the~~ir~~ respective state-wide potential study.

- Existing PURPA contracts are assumed to be renewed. Existing PURPA QFs up to the utility's "must buy" obligation MW threshold are assumed to be renewed unless the QF indicates otherwise either publicly or directly to the utility.
- Existing PURPA QFs greater than the utility's "must buy" obligation MW threshold are assumed to continue operations within the wholesale market beyond the termination date of the contract unless the QF indicates otherwise either publicly or directly to the utility.

Scenario #2 Sensitivities:

1. Fuel cost projections

Increase the natural gas fuel price projections from the base projections to at least the high EIA gas price in the most recent EIA Low Oil and Gas

[3] http://www.eia.gov/outlooks/aeo/tables_ref.php

[4] Midcentury datapoints for several climate change variables are available through Great Lakes Integrated Sciences and Assessments (GLISA) and Center for Climatic Research (CCR) at the University of Wisconsin-Madison. This information should be used to aid in establishing forecasts that include the impacts of climate change.

Supply forecast natural gas fuel price projections at the end of the study period. [28]

2. 80% carbon reduction in the utility's service territory, modeled as a hard cap on the amount of carbon emissions, by 2030 as a sensitivity.[29]

3. Ramp up the utility's EWR savings to at least 2.0%[30] of prior year sales over the course of four years, using EWR cost supply curves provided in the 2021 supplemental potential study for more aggressive potential.[31] EWR savings remain at 2% throughout the study period.