Purpose:

• Discuss necessary changes from MTEP18 for the MTEP19 Futures

Key Takeaways:

• MISO proposes no changes to MTEP18 futures (i.e. future names, narratives, and matrix)
• MISO is proposing enhancements in 6 areas
• Base data and uncertainty variables refreshed
• Soliciting further stakeholder feedback on MISO’s MTEP19 futures proposals
MTEP future definitions intended to be used for multiple cycles & may be updated annually

**Business Practice Manual-020:**

“Barring significant changes in policy and economic drivers, Future scenario definitions will continue to be used for multiple MTEP cycles...Futures definitions will be evaluated and may be updated annually for relevant changes to policy and economic drivers”

Are there any significant policy or economic changes?

- Yes → Futures Development
- No → Updates to uncertainty variables & resource forecast

MISO believes general policy, economic & industry trends continue → Update MTEP18 futures
Stakeholders generally supportive of using & updating MTEP18 Futures for MTEP19

• Stakeholder feedback received from 3 sectors
  ▪ Environmental/Other, OMS, & TOs
  ▪ Received feedback posted with today’s meeting materials

• Each respondent believed the four MTEP18 Futures still offered a reasonable set of bookends for the MTEP19 planning cycle
  ▪ The Environmental/Other did propose a 5th “Carbon Regulation Future” as an alternative
  ▪ Veriquest verbally requested a 5th future associated with more regionally distributed resource siting
Proposed MTEP19 Futures

- **Limited Fleet Change**
  - No significant drivers of fleet change
  - Thermal units retire at end of useful life
  - Renewable additions driven by RPS
  - Demand & energy growth < forecasts

- **Continued Fleet Change**
  - Fleet evolution follow historical trends
  - Coal units retire at the historical rate
  - Renewable additions > RPS
  - Demand & energy growth = forecasts

- **Distributed & Emerging Technologies**
  - Emerging & distributed technology added
  - Demand & energy growth > forecast
  - Coal units retire at historical rate / renewables grow

- **Accelerated Fleet Change**
  - Significant fleet evolution
  - Higher gas prices, 20% carbon reduction
  - Coal units retire at the historical rate and operate only in peak season.
### Proposed MTEP19 Assumptions

<table>
<thead>
<tr>
<th>MTEP19 Future</th>
<th>Limited Fleet Change</th>
<th>Continued Fleet Change</th>
<th>Accelerated Fleet Change</th>
<th>Distributed &amp; Emerging Technologies</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Demand and Energy</strong>*</td>
<td>Low* High LRZ9 Industrial</td>
<td>Base (50/50)</td>
<td>High * Low LRZ9 Industrial</td>
<td>Base + EV Energy: 0.96% Demand: 0.42%</td>
</tr>
<tr>
<td><strong>Fuel Prices</strong></td>
<td>Gas: Base -30% Coal: Base -3%</td>
<td>Base</td>
<td>Gas: Base +30% Coal: Base</td>
<td>Base</td>
</tr>
<tr>
<td><strong>Draft Demand Side Additions Total Technical Potential</strong>* &quot;By Year 2033&quot;</td>
<td>EE: 7 GW DR: 6 GW DG: 2 GW</td>
<td>EE: 10 GW DR: 7 GW DG: 2 GW</td>
<td>EE: 11 GW DR: 8 GW DG: 2 GW</td>
<td>EE: 10 GW DR: 8 GW DG: 6 GW; Storage: 2 GW</td>
</tr>
<tr>
<td><strong>Min. Renewable Penetration Level</strong>* &quot;By Year 2033 (% Wind &amp; Solar Energy)&quot;</td>
<td>10%*</td>
<td>15%*</td>
<td>30%*</td>
<td>20%*</td>
</tr>
<tr>
<td><strong>Generation Retirements¹ &quot;By Year 2033&quot;</strong></td>
<td>Coal: 11 GW Gas/Oil: 18 GW</td>
<td>Coal: 21 GW Gas/Oil: 18 GW</td>
<td>Coal: 21 GW+ Gas/Oil: 18 GW</td>
<td>Coal: 21 GW Gas/Oil: 18 GW Nuclear: 3 GW</td>
</tr>
<tr>
<td><strong>CO₂ Reduction Constraint From Current Levels by 2033</strong></td>
<td>None</td>
<td>None</td>
<td>20%</td>
<td>None</td>
</tr>
<tr>
<td><strong>Siting Methodology²</strong></td>
<td>MTEP Standard</td>
<td>MTEP Standard</td>
<td>MTEP Standard</td>
<td>“Localized”</td>
</tr>
</tbody>
</table>

*as proposed by MISO & will be informed by stakeholder feedback after enhancements are presented

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1. In Accelerated Fleet Change Scenario 21 GW of coal retired. In addition, 8 GW of coal dispatched seasonally and must-run removed on all units.
2. “Localized” renewable siting assumes that at least 50% of incremental wind and solar energy will be sourced within each Local Resource Zone. 2/3 of solar sited as distributed.
Proposed Enhancements for MTEP19 Futures

Presentation of MISO proposed MTEP19 Futures enhancements and open stakeholder discussion on each proposed enhancement
Proposed Enhancements (summary)

1. Model/cost assumptions for new wind & solar resources
2. Capacity credit for new solar resources
3. Minimum renewable penetration assumptions
4. Inclusion of units having a CPCN or equivalent
5. Enhanced Applied Energy Group (AEG) DSM programs
6. Demand and energy growth rate bands
Model/cost assumptions for new wind & solar resources
EGEAS Wind & Solar Enhancements

<table>
<thead>
<tr>
<th>Item</th>
<th>Previous Practice</th>
<th>Enhancement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tax Depreciation</td>
<td>15-yr.</td>
<td>5-yr. for Utility Wind and Solar</td>
</tr>
<tr>
<td>Construction Schedule</td>
<td>Utility Solar: 2yr. 50/50 Utility Wind: 2yr. 50/50</td>
<td>Utility Solar: 2yr. 100/0 Utility Wind: 3yr. 80/10/10</td>
</tr>
<tr>
<td>Tax Credits</td>
<td>ITC: cost adjustment PTC: Variable O&amp;M</td>
<td>ITC phase-out PTC phase-out</td>
</tr>
</tbody>
</table>

Benefits:
- More representative of recent project cost attributes
- Impacts of tax credits more accurately modeled
Federal Tax Credit values are based upon a project’s “commenced construction” date

### Actual and Modeled Schedule of Wind and Solar Tax Credits

<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>Utility Wind PTC</td>
<td>Full</td>
<td>80%</td>
<td>60%</td>
<td>40%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>Utility Solar ITC</td>
<td>30%</td>
<td>30%</td>
<td>30%</td>
<td>30%</td>
<td>26%</td>
<td>22%</td>
<td>10%</td>
<td>10%</td>
<td>10%</td>
<td>10%</td>
</tr>
</tbody>
</table>

<table>
<thead>
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</tr>
</thead>
<tbody>
<tr>
<td>Utility Wind PTC</td>
<td>Full</td>
<td>Full</td>
<td>Full</td>
<td>80%</td>
<td>60%</td>
<td>40%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>Utility Solar ITC</td>
<td>30%</td>
<td>30%</td>
<td>30%</td>
<td>30%</td>
<td>30%</td>
<td>30%</td>
<td>26%</td>
<td>22%</td>
<td>10%</td>
<td>10%</td>
</tr>
</tbody>
</table>

Preliminary results show that the tax credits would shift forward renewable in-service date, but would still follow renewable levels

Table from: [https://www.nrel.gov/docs/fy16osti/65571.pdf](https://www.nrel.gov/docs/fy16osti/65571.pdf)
**MTEP19 Wind Capital Cost**

- Mid ("Real 2017") maturity curve sourced from NREL ATB 2017: [http://www.nrel.gov/analysis/data_tech_baseline.html](http://www.nrel.gov/analysis/data_tech_baseline.html)
- High and low maturity curves are +/- 30% in 2033 of mid maturity curve

*Capital Cost shown net of PTC*
MTEP19 Solar Capital Cost

Mid ("Real 2017") maturity curve sourced from NREL ATB 2017: [http://www.nrel.gov/analysis/data_tech_baseline.html](http://www.nrel.gov/analysis/data_tech_baseline.html)

High and low maturity curves are +/- 30% in 2033 of mid maturity curve

\*Capital Cost shown net of ITC
Capacity credit assumptions for new solar resources
High PV capacity credit likely unfit for higher penetration levels

- Similar to wind, the Effective Load Carrying Capacity (“ELCC”) decreases as the penetration level increases.
- As penetration levels increase, the reserve contribution will need to decrease, or risk too little capacity being constructed.
- PV solar received a 50% capacity credit in MTEP18.
  - MISO proposes an enhancement to address this in MTEP19.
PV ELCC Enhancement

• MISO proposes to model a decreasing PV capacity contribution as the amount of forecasted PV increases in and across the Futures
  • Proposal only impacts reserve contribution in the EGEAS model, not operating capacity

• Final reserve contribution amount to be informed by MISO’s Renewable Integration Impact Assessment (RIIA) and stakeholder feedback
  ▪ Results related to the ELCC of PV will be presented at the April PAC
  ▪ Draft estimates range from 20-30% within the penetration levels seen in MTEP18
Renewable Energy
Penetration Assumptions
Need for higher renewables?

- Heard concern that the low bookend too low considering current renewable levels
- Additional question of whether the high bookend is high enough considering future trends
To ensure Futures that bookend renewable energy levels, MISO is soliciting feedback for whether or not to change renewable energy levels.

<table>
<thead>
<tr>
<th>Option</th>
<th>Limited Fleet Change</th>
<th>Continued Fleet Change</th>
<th>Accelerated Fleet Change</th>
<th>Distributed &amp; Emerging Technologies</th>
<th>Rationale</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 1:</td>
<td>10%</td>
<td>15%</td>
<td>30%</td>
<td>20%</td>
<td>With new tariffs, higher construction cost would keep renewable levels unchanged</td>
</tr>
<tr>
<td>(Current level)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Option 2: (+5% to all)</td>
<td>15%</td>
<td>20%</td>
<td>35%</td>
<td>25%</td>
<td>Current wind PPA prices and queue indicates renewable levels will be higher than what is currently modeled</td>
</tr>
<tr>
<td>Option 3: (+10% to AFC)</td>
<td>10%</td>
<td>15%</td>
<td>40%</td>
<td>20%</td>
<td>To ensure bookend, a high renewable penetration Future should be considered</td>
</tr>
</tbody>
</table>
Inclusion of units having regulatory approval
Inclusion of regulatory approved units

- Previous MTEP feedback indicated MISO should include such units in the base economic cases
  - Units with approved CPCN/CON/CPN (or equivalent) are nearly certain to be constructed
  - Would limit Regional Resource Forecast (RRF) unit needs if state approvals included
Economic Base Model* Enhancement

Current base model

- Existing active generating units
- Planned queue units with signed Generator Interconnection Agreement (GIA)

What’s new?

- Non-signed GIA units with approved CPCN/CON/CPN (or equivalent)
- Included as a new unit with specific size, type, location, & timing of the approved unit
- State regulators or utilities will need to send MISO the approved unit-specific information

Units with Certificate of Public Convenience and Necessity (CPCN) have high level of certainty; submissions of such approved units will be included in the base model*

*Update only applied to MTEP Economic Model
Enhanced Applied Energy Group DSM programs
Applied Energy Group DSM Programs

• MTEP17 & MTEP18 utilized AEG DSM programs based on the MTEP16 Futures

• MISO commissioned AEG to develop new DSM programs based off on the MTEP18 Futures
  ▪ MISO just received the newly created DSM programs from AEG
  ▪ The following values are draft & subject to change

• AEG DSM Workshop scheduled - March 22, 2018
# MTEP19 DR, EE, & DG Programs

<table>
<thead>
<tr>
<th>MTEP19 Programs</th>
<th>Limited Fleet Change</th>
<th>Continued Fleet Change</th>
<th>Accelerated Fleet Change</th>
<th>Distributed and Emerging Technology</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Capacity (GW)</td>
<td>Energy (GWh)</td>
<td>Capacity (GW)</td>
<td>Energy (GWh)</td>
</tr>
<tr>
<td>Demand Response (DR)</td>
<td>6.4</td>
<td>470</td>
<td>6.9</td>
<td>505</td>
</tr>
<tr>
<td>Energy Efficiency (EE)</td>
<td>8.1</td>
<td>49,253</td>
<td>9.5</td>
<td>56,809</td>
</tr>
<tr>
<td>Distributed Generation (DG)</td>
<td>1.9</td>
<td>3,774</td>
<td>2.2</td>
<td>4,308</td>
</tr>
</tbody>
</table>

**Technical Potential** represents the maximum feasible potential under each scenario. Existing DR not yet deducted from technical potential. Only economically viable programs will be implemented in the MTEP19 models (each program will be offered against supply-side alternatives).

State mandates & goals met in all MTEP19 Futures, additional DR/EE/DG up to listed potential allowed to be economically selected.

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* AEG Report
** Existing DR programs will be modeled as base assumptions
Demand and Energy Growth Rate Bands
Demand and Energy Growth Rates

- Module E base growth rates have decreased greatly over 4 years
- Prior MTEPs used .5 or 1.5 times the base growth rate for low & high, indicative of 10/90 and 90/10 forecasts
- MISO believes this approach may no longer provide broad bookends

<table>
<thead>
<tr>
<th>MTEP</th>
<th>Demand Growth Rate %</th>
<th>Energy Growth Rate %</th>
</tr>
</thead>
<tbody>
<tr>
<td>MTEP16</td>
<td>0.75%</td>
<td>0.82%</td>
</tr>
<tr>
<td>MTEP17</td>
<td>0.64%</td>
<td>0.65%</td>
</tr>
<tr>
<td>MTEP18</td>
<td>0.47%</td>
<td>0.49%</td>
</tr>
<tr>
<td>MTEP19</td>
<td>0.30%</td>
<td>0.46%</td>
</tr>
</tbody>
</table>
Demand & Energy High/Low

<table>
<thead>
<tr>
<th></th>
<th>MTEP18 Method</th>
<th>MTEP19 Proposed Method</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low (10/90)</td>
<td>Mid (50/50)</td>
</tr>
<tr>
<td>Demand</td>
<td>0.23%</td>
<td>0.47%</td>
</tr>
<tr>
<td>Energy</td>
<td>0.25%</td>
<td>0.49%</td>
</tr>
</tbody>
</table>

- Current proposal to double base rate for the high and no growth for a low
- With no growth, assumption is a net forecast

How should gas-price sensitive LRZ9 industrial loads be treated in no growth situations?
Adjustment ensures breadth of growth assumptions

Source: preliminary Module E data (to be finalized April 2018)
DET growth now closer to AFC

Proposed MISO Energy (TWh)

- MTEP19 Proposed CFC (Mod E 50/50) 0.46%
- MTEP19 Proposed DET 0.96%
- MTEP19 Proposed LFC 0.00%
- MTEP19 Proposed AFC 0.92%

Source: preliminary Module E data (to be finalized April 2018)
Historical Operating, Forecasted Module E, and Proposed Annual Load Factors

Historical, Module E, LFC, CFC, AFC, DET

58% 61% 64% 67% 68%

Refreshed / Updated Uncertainty Variable Data

Presentation & review of refreshed uncertainty variable information from various data sources utilizing the MTEP18 methodologies (i.e. no change in process)
Load Serving Entities’ demand forecast continues to trend lower

Source: preliminary Module E data (to be finalized April 2018)
Regional variations modeled within MTEP demand and energy forecasts*

<table>
<thead>
<tr>
<th>LRZ 1 0.67%</th>
<th>LRZ 2 0.27%</th>
<th>LRZ 3 0.60%</th>
<th>LRZ 4 0.18%</th>
<th>LRZ 5 0.21%</th>
<th>LRZ 6 0.19%</th>
<th>LRZ 7 -0.28%</th>
<th>LRZ 8 0.61%</th>
<th>LRZ 9 0.49%</th>
<th>LRZ 10 0.27%</th>
</tr>
</thead>
<tbody>
<tr>
<td>MISO 0.3%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LBA 1 -0.08%</td>
<td>LBA 02 0.14%</td>
<td>LBA 03 0.55%</td>
<td>LBA 04 0.69%</td>
<td>LBA 05 1.17%</td>
<td>LBA 06 -0.39%</td>
<td>LBA 07 1.06%</td>
<td>LBA 08 -0.25%</td>
<td>LBA 09 0.25%</td>
<td></td>
</tr>
<tr>
<td>LBA 10 0.93%</td>
<td>LBA 11 -0.25%</td>
<td>LBA 12 1.07%</td>
<td>LBA 13 1.06%</td>
<td>LBA 14 0.61%</td>
<td>LBA 15 0.35%</td>
<td>LBA 16 0.53%</td>
<td>LBA 17 0.20%</td>
<td>LBA 18 1.15%</td>
<td></td>
</tr>
<tr>
<td>LBA 19 0.18%</td>
<td>LBA 20 0.46%</td>
<td>LBA 21 0.45%</td>
<td>LBA 22 0.70%</td>
<td>LBA 23 0.16%</td>
<td>LBA 24 0.31%</td>
<td>LBA 25 0.14%</td>
<td>LBA 26 0.77%</td>
<td>LBA 27 -0.66%</td>
<td></td>
</tr>
<tr>
<td>LBA 28 -0.05%</td>
<td>LBA 29 0.18%</td>
<td>LBA 30 0.45%</td>
<td>LBA 31 1.52%</td>
<td>LBA 32 0.59%</td>
<td>LBA 33 0.07%</td>
<td>LBA 34 -0.31%</td>
<td>LBA 35 0.15%</td>
<td>LBA 36 1.38%</td>
<td></td>
</tr>
</tbody>
</table>

*All growth rates represent a 10-year compound annual growth rate, beginning in 2018.
Load Serving Entities’ energy forecast follows similar trend as demand forecast

Source: preliminary Module E data (to be finalized April 2018)
MTEP19 Natural Gas Price Forecast
(Annual Average Values Henry Hub in Nominal 2018 $)

Using the MTEP18 methodology, NYMEX was used for the first two years and an average of the EIA and Wood Mackenzie forecasts for the out years.

Source: EIA Annual Energy Outlook 2018; Wood Mackenzie North America Power & Renewables Long-Term Outlook 2017, NYMEX, retrieved from SNL
MTEP19 Fuel Forecast Bands
(Annual Average Values Henry Hub in Nominal 2018 $)

Source: EIA Annual Energy Outlook 2018; Wood Mackenzie North America Power & Renewables Long-Term Outlook 2017, NYMEX, retrieved from SNL
MTEP19 assumed coal & natural gas/oil retirement by 2033

Age limits based on statistical analysis*
Nuclear license expiration used for DET

*Based on statistical analysis of MISO fleet with support from industry analysis (NREL)
MTEP19 Capital Costs
(Capital costs of unit technology types in 2018 $/kW)

Source: 2017 NREL Annual Technology Baseline (ATB) using updated inflation rate (1.42% actual)  
https://data.nrel.gov/files/71/2017-ATB-data.xlsx

Input Lazard link  

Wind: $1,711, $1,505
Solar Utility: $2,042, $1,419
Geothermal: $5,885, $5,802
Hydropower: $3,886, $3,830
Gas CC: $1,079, $1,048
Gas CT: $922, $899
Coal: $3,750, $3,674
Nuclear: $5,908, $5,609
Biopower: $3,916, $3,860
Energy Storage: $2,710, $1,542

MTEP18  MTEP19
As vetted last year, batteries modeled at 4 hour depth of charge, so $$/kWh \times 4 = $$/kW
# MTEP19 Uncertainty Variables

All costs are overnight construction costs in 2018 dollars; sourced from NREL Annual Technology Baseline 2017; MTEP19 varies cost maturity over time versus having high and low starting points at the front of the study period.

Mid values for years 1 - 10 of demand growth are derived from Module-E; Years 11-20 are extrapolated; H & L values are derived using updated demand growth assumption.

Energy values are calculated using Module E, the corresponding demand forecast and historical load factors. Add .5% EV growth for DET Future.

NYMEX, EIA, and Wood Mackenzie

Powerbase default for oil is $9.87/MMBtu

Powerbase range for coal is $1 to $4, with an average value of $1.84/MMBtu

Tonnage limit applies all units evenly

Lazard used for Li Ion battery costs

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<table>
<thead>
<tr>
<th>Uncertainty</th>
<th>Unit</th>
<th>Low (L)</th>
<th>Mid (M)</th>
<th>High (H)</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Generation Capital Costs¹</td>
<td>($/KW)</td>
<td>3,674</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal</td>
<td>($/KW)</td>
<td>1,048</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CC</td>
<td>($/KW)</td>
<td>899</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CT</td>
<td>($/KW)</td>
<td>5,609</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nuclear</td>
<td>($/KW)</td>
<td>1,505</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind-Onshore¹</td>
<td>($/KW)</td>
<td>3,941</td>
<td></td>
<td></td>
</tr>
<tr>
<td>IGCC</td>
<td>($/KW)</td>
<td>5,092</td>
<td></td>
<td></td>
</tr>
<tr>
<td>IGCC w/ CCS</td>
<td>($/KW)</td>
<td>2,179</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CC w/ CCS</td>
<td>($/KW)</td>
<td>5,458</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pumped Storage Hydro</td>
<td>($/KW)</td>
<td>1,542</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Battery Storage (Lithium Ion)¹,²</td>
<td>($/KW)</td>
<td>1,313</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Compressed Air Energy Storage</td>
<td>($/KW)</td>
<td>1,419</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PhotovoltaicAC¹</td>
<td>($/KW)</td>
<td>3,860</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Biomass</td>
<td>($/KW)</td>
<td>3,830</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Conventional Hydro</td>
<td>($/KW)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

¹ All costs are overnight construction costs in 2018 dollars; sourced from NREL Annual Technology Baseline 2017; MTEP19 varies cost maturity over time versus having high and low starting points at the front of the study period.

² Mid values for years 1 - 10 of demand growth are derived from Module-E; Years 11-20 are extrapolated; H & L values are derived using updated demand growth assumption.

³ Energy values are calculated using Module E, the corresponding demand forecast and historical load factors. Add .5% EV growth for DET Future.

⁴ NYMEX, EIA, and Wood Mackenzie

⁵ Powerbase default for oil is $9.87/MMBtu

⁶ Powerbase range for coal is $1 to $4, with an average value of $1.84/MMBtu

⁷ Tonnage limit applies all units evenly

⁸ Lazard used for Li Ion battery costs
All costs are overnight construction costs in 2018 dollars; sourced from NREL Annual Technology Baseline 2017; MTEP19 varies cost maturity over time versus having high and low starting points at the front of the study period.

Mid values for years 1 - 10 of demand growth are derived from Module-E; Years 11-20 are extrapolated; H & L values are derived using updated demand growth assumption.

Energy values are calculated using Module E, the corresponding demand forecast and historical load factors. Add .5% EV growth for DET Future.

NYMEX, EIA, and Wood Mackenzie

Powerbase default for oil is $9.87/MMBtu

Powerbase range for coal is $1 to $4, with an average value of $1.84/MMBtu

Tonnage limit applies all units evenly

Lazard used for Li Ion battery costs

<table>
<thead>
<tr>
<th>Uncertainty</th>
<th>Unit</th>
<th>Low (L)</th>
<th>Mid (M)</th>
<th>High (H)</th>
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<tbody>
<tr>
<td>Demand and Energy</td>
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</tr>
<tr>
<td>Baseline 20-Year Demand Growth Rate</td>
<td>%</td>
<td>0.0%</td>
<td>0.3% (.42% in DET)</td>
<td>0.6%</td>
</tr>
<tr>
<td>Baseline 20-Year Energy Growth Rate</td>
<td>%</td>
<td>0.0%</td>
<td>0.46%</td>
<td>0.92% (0.96% in DET)</td>
</tr>
<tr>
<td>Demand Response &amp; Energy Efficiency Levels - EE trimmed by estimated Mandates &amp; Goals</td>
<td>%</td>
<td>AEG Limited Fleet Change</td>
<td>CFC: AEG Reference Case (Mid Growth)</td>
<td>AEG Accelerated Fleet Change</td>
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<tr>
<td>Natural Gas</td>
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<tr>
<td>Natural Gas</td>
<td>($/MMBtu)</td>
<td>Forecast-30%</td>
<td>Combined NYMEX, EIA, and Wood Mackenzie</td>
<td>Forecast +30%</td>
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<tr>
<td>Fuel Prices (Starting Values)</td>
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</tr>
<tr>
<td>Oil</td>
<td>($/MMBtu)</td>
<td>Powerbase default</td>
<td></td>
<td>Powerbase default</td>
</tr>
<tr>
<td>Coal</td>
<td>($/MMBtu)</td>
<td>Powerbase default -3%</td>
<td>Powerbase default</td>
<td></td>
</tr>
<tr>
<td>Uranium</td>
<td>($/MMBtu)</td>
<td></td>
<td>Powerbase default</td>
<td></td>
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Tonnage limit applies all units evenly

Lazard used for Li Ion battery costs
MTEP19 Futures Schedule & Next Steps

Review of MTEP19 futures development schedule and near-term next steps, including a request for stakeholder feedback.
MTEP19 Futures Schedule

January PAC
- Schedule & Expectations

February PAC
- Review uncertainty variables
- Discuss impacts of equal weightings
- Solicit feedback

March Workshop
- Further discuss any changes
- Discuss feedback received & present proposed futures

June PAC
- Finalize MTEP19 future definitions

September PAC
- Final MTEP19 futures results & draft siting results
Feedback Request

- Feedback due Friday, April 20, 2018
  - Feedback form posted with today’s meeting materials
  - Please send feedback to MTEPFutures@misoenergy.org

- Feedback specifically requested on:
  - Renewable modeling proposal
  - Updated solar capacity credit
  - Renewable energy levels
  - Demand and energy growth rates
Next Steps

- Futures definitions finalized & workshop feedback report
- Distributed bus siting survey posted for feedback

Retirement assumptions posted for feedback

Final resource expansion results presented & draft siting results posted

April PAC

June 1st

June PAC

July 27th

Sep. PAC

Oct 12th

Feedback Due
Approved CPCN/CON units and retirement assumption updates for inclusion in MTEP19 resource expansion model

Feedback Due
Distributed bus siting survey

Feedback Due
Draft siting results
Questions?
Contact Information

MTEP Futures Team:
MTEPFutures@misoenergy.org

Tony Hunziker:
AHunziker@misoenergy.org
Appendix Slides
Future Narrative: Limited Fleet Change

Existing generation fleet remains relatively static without significant drivers of change. Some coal fleet reductions are expected as units reach the end of useful life. Renewable additions are driven solely by current Renewable Portfolio Standards under low demand & energy growth rates.

- Footprint wide, demand & energy growth rates are low; however, as a result of low natural gas prices, industrial production along the Gulf Coast increases.

- Natural gas prices are low due to increased well productivity and supply chain efficiencies along with low demand & energy.

- Low demand & energy and natural gas prices reduce the demand for and economic viability of new generation technologies.

- Thermal generation retirements are driven by unit useful life limits. Nuclear units are assumed to have license renewals granted and remain online.

- Lower levels of demand-side management programs are assumed due to low demand & energy.
Future Narrative: Continued Fleet Change

The fleet evolution trends of the past decade continue. Coal retirements reflect historical retirement levels based on average age of retirement. Renewable additions continue to exceed current Renewable Portfolio Standard Requirements as a result of economics, public appeal, and the potential for future policy changes. Natural gas reliance increases as a result of new capacity needed to replace retired coal capacity.

- Demand and energy growth rates are modeled at a level equivalent to a 50/50 forecast.
- Natural gas prices are consistent with industry long-term reference forecasts.
- Renewable additions continue along current trends. Wind & solar serve 15% of MISO energy by 2032.
- Maturity cost curves for renewable resources reflect some advancement in technology and supply chain efficiencies.
- Oil and gas generators retired at the useful life limit age. Coal units will be retired reflecting age and historical retirements beyond age limits. Nuclear units are assumed to have license renewals granted and remain online.
- Demand-side management programs modeled to reflect growth and technical potential of current programs.
A robust economy with increased demand & energy drives higher natural gas prices. Carbon regulations targeting a 20% reduction from current levels are enacted in response to increased demand & energy, driving coal to both retirement and decreased production. Increased renewable additions are driven beyond renewable portfolio standards by need for new generation, technological advancement, and carbon regulation. Natural gas reliance increases as a result of new capacity needs driven by the need to replace retired capacity and provide flexibility to support the integration of intermittent renewable resources.

- Demand & energy grows at a high rate due to a robust economy; however, as a result of high natural gas prices, industrial production along the Gulf Coast decreases.
- Natural gas prices are high due to increased demand.
- Retirements, economics, and potential regulations drive renewable additions. Maturity cost curves for renewable technologies applied reflecting advancement in technologies.
- Oil and gas generators will be retired in the year the age limit is reached. Coal units will be retired reflecting age and economics. Nuclear units are assumed to have license renewals granted and remain online.
- A 20% carbon reduction for current levels is modeled to reflect future national or state-level carbon regulation.
- High demand & energy levels and carbon regulation drive greater potential for demand-side management programs.
Future Narrative: Distributed & Emerging Technology

Fleet evolution trends continue, primarily driven by local policies and emerging technology adoption. State level policies reflect desires for local reliability and optionality. Mid-level coal retirements reflect economics and age limits. Increased renewable additions are driven by favorable economics resulting from technological advancements and state-level renewable portfolio standards and goals with targeted increases in distributed solar. Natural gas reliance increases as a result of new capacity needs driven by load growth largely driven by electric vehicles, the need to replace retired capacity and provide flexibility to support the integration of intermittent renewable resources.

- Demand and energy forecast begins level equivalent to a 50/50 forecast and has high growth rate to reflect adoption of electric vehicle technology on a broader scale. Energy grows faster than demand reflecting smart-charging.
- Natural gas prices are consistent with industry long-term reference forecasts.
- Generation siting shows a strong preference for localized energy and capacity self-sufficiency within state jurisdictions.
- Maturity cost curves for renewable technologies applied reflecting advancement in technologies and supply-chain efficiencies. Renewable additions reach about 20% of MISO energy by 2032, increase from 15% in Continued Fleet Change Future comes primarily from solar.
- Increased deployment of energy storage devices driven by economies of scale resulting from commercial mass production of lithium ion batteries and other viable technologies.
- Oil and gas generators will be retired in the year the age limit is reached. Coal units will be retired reflecting age and economics. Nuclear units are assumed to have license renewals granted and remain online.
- Demand-side management programs grow in scale and scope due to technological advancement and economies of scale.
MTEP19 Future Weights

- Beginning in MTEP19, Futures will be equally weighted

<table>
<thead>
<tr>
<th>MTEP19 Future</th>
<th>MTEP Future Weighting</th>
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<tbody>
<tr>
<td>Limited Fleet Change</td>
<td>25%</td>
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<tr>
<td>Continued Fleet Change</td>
<td>25%</td>
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<tr>
<td>Accelerated Fleet Change</td>
<td>25%</td>
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<tr>
<td>Distributed &amp; Emerging Technologies</td>
<td>25%</td>
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</tbody>
</table>
MTEP19 Futures Matrix

<table>
<thead>
<tr>
<th>Future</th>
<th>Uncertainties</th>
<th>Maturity Cost Curve</th>
<th>Demand and Energy</th>
<th>Fuel Cost (Starting Price)</th>
<th>Fuel Escalations</th>
<th>Emission Costs</th>
<th>Other Variables</th>
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<tr>
<td>Limited Fleet Change</td>
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<td>Continued Fleet Change</td>
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<td>Distributed and Emerging</td>
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<td>Accelerated Fleet Change</td>
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The Levelized Cost of Energy (LCOE) calculations were prepared using rough assumptions of how specific types of units would be dispatched in the EGEAS model.

The capacity factor used reflects average unit type dispatches seen from previous MTEPs: CT- 9%, CC- 60%, Wind - 43%, Solar- 20%, Battery – 30%

Capital cost and fuel forecast aligns with MTEP modeled assumptions presented today.

Tax assumptions used are based off of Attachment-O.