MODELING SUBCOMMITTEE MEETING MATERIALS

Modeling Subcomittee Meeting Attendance

First Name	Last Name	Organization	Meeting 1 3/18/20	Meeting 2 5/28/20	Meeting 3 7/29/20	Meeting 4 9/30/20
Alissa	Bemis	Great Plains Institute			X	X
Jessica	Burdette	MN Department of Commerce	X			
John	Christensen	Minnesota Power		X	X	X
Riley	Conlin	Stoel Rives	X			
Chris	Davis	MN Chamber of Commerce	X			
Trevor	Drake	Great Plains Institute	X	X	X	X
Jay	Eidsness	MN Center for Environmental Advocacy				X
Allen	Gleckner	Fresh Energy	X	X	X	X
Chelsea	Hotaling	Energy Futures Group	X	X	X	
Will	Kenworthy	Vote Solar	X	X	X	X
Taylor	McNair	GridLab	X	X		
Evan	Mulholland	MN Center for Environmental Advocacy	X	X	X	X
Eric	Palmer	Minnesota Power	X	X	X	X
Audrey	Partridge	Center for Energy and Environment	X	X	X	
Doug	Scott	Great Plains Institute	X			
Anna	Sommer	Energy Futures Group	X	X	X	X
Kate	Sullivan	Great Plains Institute	X	X	X	X
Andrew	Twite	Fresh Energy			X	X
Laurie	Williams	Sierra Club - Minnesota Chapter	X	X	X	X

Minnesota Power
2020 Integrated Resource Plan

Modeling Subcommittee Meeting 1
Wednesday, March 18th 10:30am-2:00pm

****Zoom Meeting -- click here a few minutes before 10:30am:****
https://betterenergy.zoom.us/j/5371528831

Meeting Objectives:

1. Develop collective objectives and ground rules for this group
2. Build a shared understanding of how EnCompass will be used in the IRP
3. Explore and discuss perspectives on an initial set of key modeling assumptions
4. Identify next steps for future meetings (and how many meetings might be needed)

Agenda:

**** Please join meeting a few minutes before 10:30am so we can start on time****

10:30AM **WELCOME, INTRODUCTIONS, AGENDA REVIEW**

10:35AM **OBJECTIVES AND GROUND RULES**

- Objectives – what does everybody want to get out of this group?
- What are a set of appropriate ground rules for conducting these conversations in advance of the formal regulatory process?

11:00AM **OVERVIEW ON ENCOMPASS MODELING**

11:15AM **DISCUSSION WITH MN POWER ON MODELING ASSUMPTIONS**

- Supply- and demand-side resource alternatives
- Load forecast methodologies
- List of sensitivities
- Perspectives on solar + storage, with example

12:00PM **BREAK FOR LUNCH**

12:45PM **DISCUSSION WITH MN POWER (CONTINUED)**

2:00PM **ADJOURN**

MINNESOTA POWER 2020 INTEGRATED RESOURCE PLAN

Modeling Subgroup Meeting 1

Wednesday, March 18th 10:30am-2:00pm

Via Zoom

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2019 NTEC Order Point:

In developing the modeling analysis to be used in its next resource plan, Minnesota Power shall consult with stakeholders, including but not limited to the Department of Commerce and the Clean Energy Organizations, regarding the Company's modeling inputs and parameters.

OBJECTIVES AND GROUND RULES:

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OBJECTIVES AND GROUND RULES CONTINUED:

- MP is seeking feedback from stakeholders on assumptions used in the IRP modeling analysis.

- Any comments or suggestions made by stakeholders or the Company during these meetings is not intended to bind parties later in the IRP proceeding and associated modeling analysis.

- Notes will be taken and submitted in the IRP, although comments or suggestions will not be tied to a specific party or individual.

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Topics and Questions

Potential inputs to model:

- Re-firing of Boswell to include green hydrogen feedstocks
- Renewable resources
- Distributed generation
- Carbon capture

Modeling details:

- What are the scenarios?
- What assumptions are being made?
- What are the sensitivities?
- What is the base case?

Would like actual data characterizing inputs that MN Power intends to use

What is the plan and timeline for involving stakeholders?

OVERVIEW ON ENCOMPASS MODELING

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DISCUSSION WITH MN POWER ON MODELING ASSUMPTIONS

- Supply- and demand-side resource alternatives
- Load forecast methodologies
- List of sensitivities
- Perspectives on solar + storage, with example

Supply & Demand Side Alternatives

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Baseload
- Coal w/ 80% CCS
- Nuclear - Modular

Bilateral Contracts
- "Bridge" Purchases

Intermediate
- 1x1 CC

Peaking
- Combustion Turbine
- Reciprocating Internal Combustion Engine
- Aeroderivative
- Solar + Li-on

Renewable
- Wind
- Solar Existing Infrastructure

Storage
- Li-on
- Flow Battery
- Pumped Hydro
- Compressed Air

Customer Products
- Large Power DR
- Residential / Commercial Load Control
- Energy Efficiency

Other Alternatives That Should be Considered?

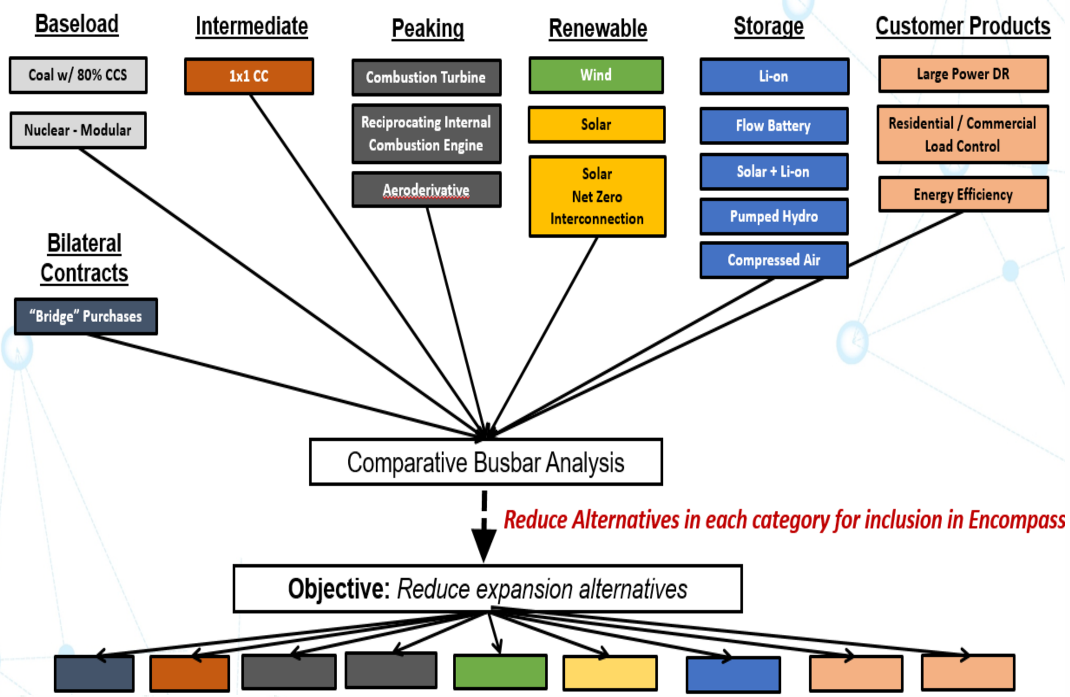
Comparative Busbar Analysis

Reduce Alternatives in each category for inclusion in Encompass

Objective: *Reduce expansion alternatives*

Considerations for Alternatives

Data Source



Annual Forecast Report Process

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1. Data Gathering
- Energy, customer count by sector
- Peak demands
- Weather (HDDs,CDDs, Peak day temperature and humidity)
- Electric revenue and prices, by sector
- National and Regional economic metrics

2. Data Preparation and Development
- Data screen and correction
- Weather data analysis
- Projections of industrial production indices (IPI)
- Simulations of regional economic development under each scenario (REMI)
- Detrend, deseasonalize, difference
- Identify any changes in variables from last year's database

3. Specification Search
- Examine plausible variable combinations
- Explore alternative binary structures
- Generate and Rank all models by Out-Sample forecast error (CV testing)
- Filter model list for
  - Redundant/duplicate models
  - Statistical criteria (P-values & VIF)

4. Forecast Determination
- Assess plausibility of models
  - Projected growth rates
  - Intuitiveness of predictor variables
- Narrow potential model list

5. Forecast Review, Verification
- Gain consensus on optimal models
- Produce summary of findings and recommendations

6. Company Review and Approval

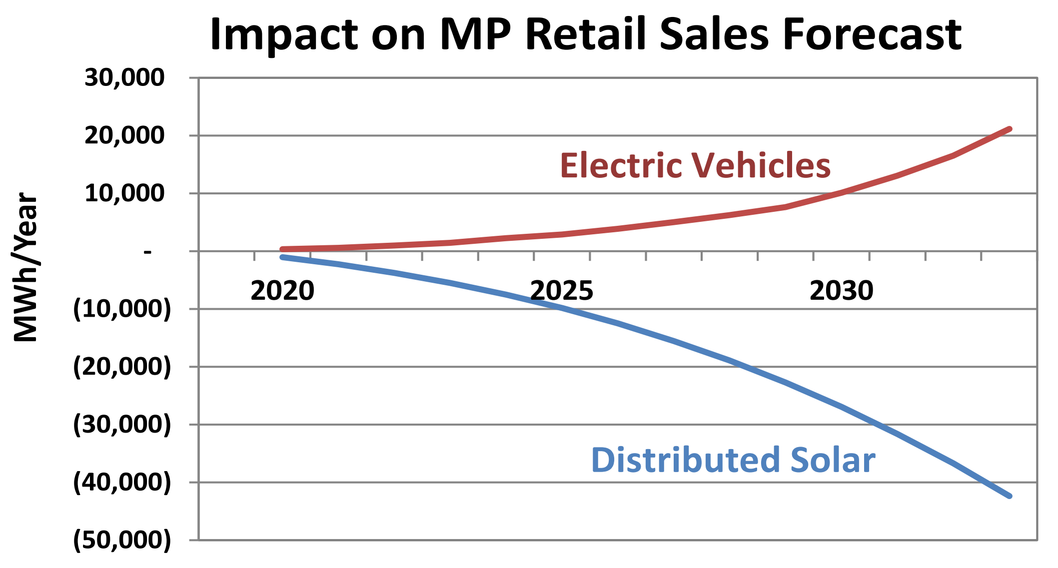
Conservation, EV & Solar

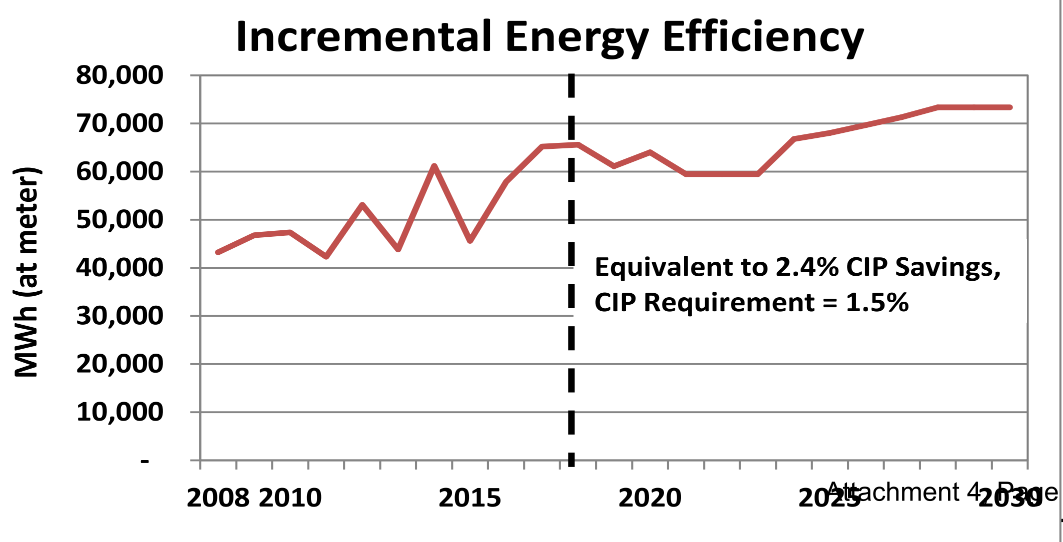
Note: AFR 2020 Preliminary Assumption

- Reduces sales by 60-75 GWh/yr
- Assumptions are consistent with updated CEE potential study, CIP Triennial, & IRP
- EE included in residential, commercial, public authorities, & resale models
- Industrial savings are assumed to be inherent in forecast

- Only residential adoption (fleet vehicle inclusion being monitored for future filings)
- Currently serving 135 vehicles (0.12% penetration)
- Forecasting about 4,200 vehicles (3.7% penetration) by 2030

- Modeled residential & commercial
- Currently about 3.3 MW of <40 KW capacity (74% of small scale mandate)
- Projecting 27 MW of new installed capacity (~30 MW total) by 2030
- New installs will displace about 27,000 MWh (1.2%) of MP sales to residential & commercial classes





Minimum Required State Futures for Resource Planning

Scenarios:	Before 2025		2025 and Thereafter	
	Environmental Cost	Regulatory Cost	Environmental Cost	Regulatory Cost
Low Environmental Cost	Low End	-	Low End	-
High Environmental Cost	High End	-	High End	-
Low Environmental/ Regulatory Costs	Low End	-		$5/Ton
High Environmental/ Regulatory Costs	High End	-	-	$25/Ton
Omitting CO_2 Cost Considerations	-	-	-	-

MINNESOTA POWER 2020 INTEGRATED RESOURCE PLAN

LUNCH BREAK

Modeling Subgroup Meeting 1

Wednesday, March 18th 10:30am-2:00pm

Via Zoom

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Sensitivities for Consideration

Renewable Availability

Technology Innovations

Commodity Market Volatility

Energy Market Volatility

Fuel Market Volatility

Customer Outlook Uncertainty

Seasonal Demand Changes

Resource Adequacy

Energy Adequacy

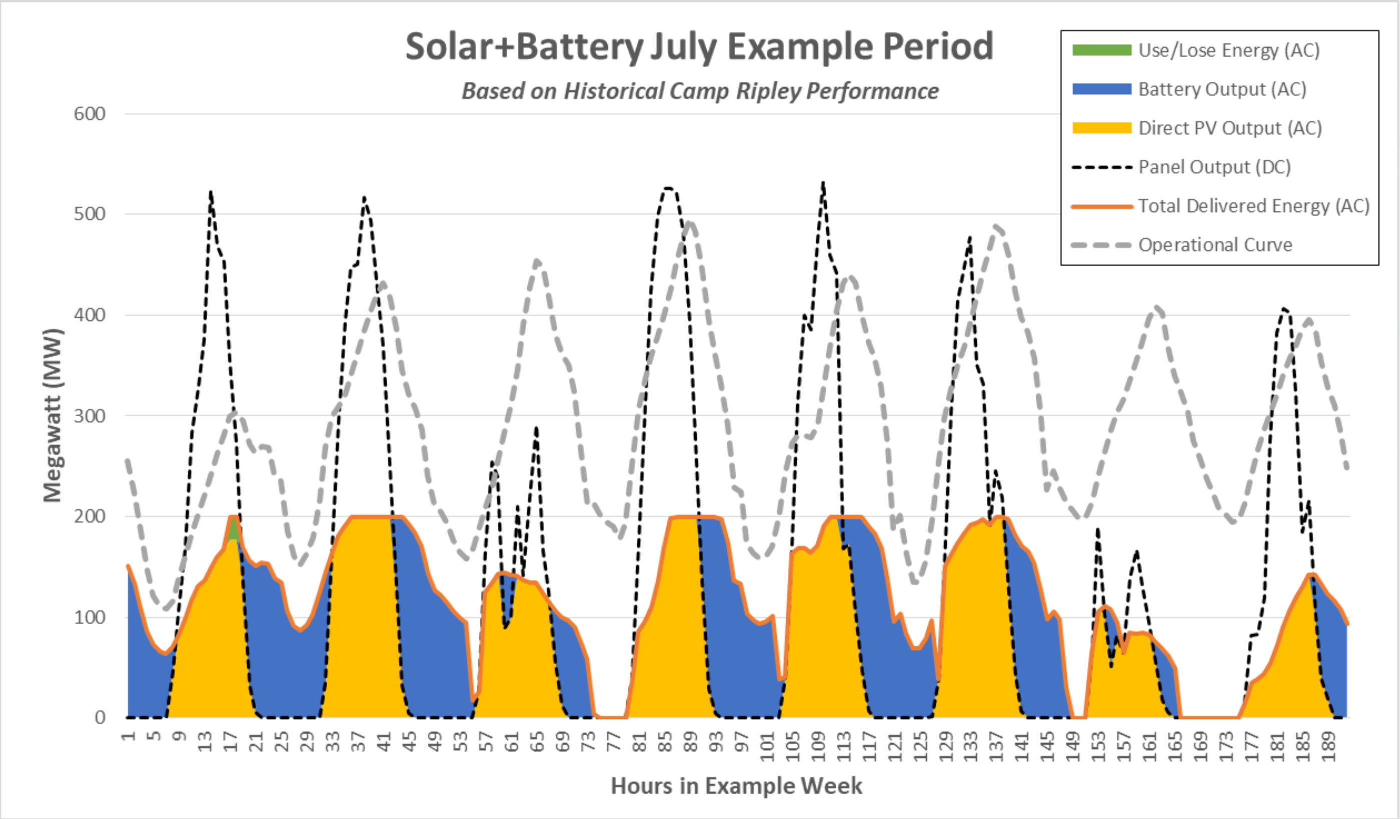
Solar-Storage Approach in IRP Modeling

- High DC/AC Solar PV Ratio
- Long-term Storage Duration
- Shared AC Infrastructure (Collector Systems, Control Systems, Inverters, etc.)
- Reduced Energy Losses

Solar-Storage Approach in IRP Modeling

- 200 MW of AC Inverter Capacity
- 3.0 DC/AC Ratio
- 8 Hours of DC-Coupled Storage

- Key Specifications:
  - ~775 GWh of DC energy
  - ~700 GWh of AC energy
    - *45% used in real-time*
    - *55% stored for future*
  - ~41% Capacity Factor



Next Steps

- **How often does this subgroup want to meet?**
- **What do stakeholders want to hear about at next meeting?**

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MP IRP Modeling Subcommittee Meeting

March 18th, 2020

Via Zoom

Participants: Trevor Drake, Kate Sullivan, Audrey Palmer, Eric Palmer, John Christenson, Allen Gleckner, Chelsea Hotaling, Taylor McNair, Riley Conlin, Evan Mulholland, Will Kenworthy, Anna Sommer, Chris Davis*, Jessica Burdette*, Laurie Williams

**The Department of Commerce is an observer in this process*

Goal of this subgroup is for MN Power to get feedback from stakeholders on assumptions used in IRP modeling analysis

Discussion with MN Power on Encompass

- Minnesota Power has the tool in house and started to set up the tool for the IRP.
- Energy Futures Group used EnCompass previously in New Mexico and will be using it in the Xcel IRP
- A participant noted that users are running the expansion plan analysis looking at only two days a month versus the typical 7 day week modeled in Strategist. The two day approach is done to minimize run time for the expansion plan analysis.

Discussion with MN Power on modeling assumptions

Supply and demand side resource alternatives

- Key groups – always considered, but sometimes not modeled due to costs
- Initial assumptions to include in this IRP
    - Baseload: coal with 80% carbon capture and nuclear (but limited by moratorium)
    - Bilateral contracts: bridge purchases available to the model, to avoid building something early than needed.
    - Intermediate: 1 on 1 combined cycle turbine (600MW range) – won't look at 2 on 1's unless receive feedback otherwise
    - Peaking: new solar + lithium ion options
    - Renewable:
        - wind in upper Midwest
        - solar
        - and solar at existing infrastructure
    - Storage:
        - Lithium ion – 4-8 hour duration
        - Flow battery – 8-16 hour
        - Pumped hydro – long duration
        - Compressed air – new option looking at

    - Customer products: large power demand response, additional EE, and residential/commercial load control
- Questions/comments:
    - Does the categorization apply to just the organization of this graphic? Or will that impact the modeling?
        - Mostly just the slide. If we look at three different options for storage, and one was far out for cost but had similar characteristics, we might screen it out. We stack all these resources against each other in the model and let the model pick.
        - You can look at more alternatives in EnCompass than in strategist.
    - Hybrid resources – something that may become more of a realistic option as this process moves forward.
        - Energy Systems International Group has some resources
        - GridLab has never modeled it but could do some digging. Mark Ahlstrom has been thinking about it.
        - In EnCompass you must represent battery and wind separately, and there's a switch to flip to show that the battery needs to be charged with the wind resource, but what matters more is the accredited capacity.
            - MISO is working determining capacity credit for hybrid storage resources.
        - ITC – can claim this for hybrid projects with ITC-eligible resources (e.g., wind)
        - Costs you assign to a hybrid – if the cost is representative of one inverter, or a shared inverter, or less standalone components, that impacts whether it gets chosen when compared to standalone projects.
        - Comes down to whether we're talking AC or DC coupled devices.
    - Can you explain what solar existing infrastructure means?
        - Solar that would be installed at an existing point of interconnection, avoiding the need for new investment in utility infrastructure to interconnect

Data source considerations

- Have previously purchased technology estimates from third-party engineering companies, but tends to limit transparency
- Lots of opportunities to leverage public data. Might still turn to engineering companies as needed but will try to use publicly available data as much as reasonable.
- Questions/comments:
    - NREL sometimes overestimates the cost of solar – can introduce more uncertainty around those cost estimates, but not sure about 2019 ATB.
    - Coal with 80% carbon capture is a wide range with a lot of cost uncertainty.
    - Seems like Minnesota Power is on the right track with these data sources. There was a general understanding why Minnesota Power would use a third-party engineering company estimate for certain technologies.
    - How will previous 2016-2017 Minnesota Power RFP's be incorporated into this round of modeling?
        - MP feels they are dated and will likely not incorporate them
        - Other utilities have done more recent RFP's, can MP incorporate their findings?

            - Consistently coming in lower than people expect, so factoring that dynamic in would be preferable – **MP would be willing to look at NIPSCO data and follow up.**
  - RMI might also be another source for data on storage, in addition to Lazard. Unsure if this information is publicly available though.
  - On energy efficiency, has MP thought through this beyond load forecasting? Having it participate on a cost basis?
    - Included EE as a resource alternative and plan to include higher levels of EE in this round of modeling, as done in previous IRPs
    - CEE is helping to put together EE modeling scenarios based on the State wide Potential Study
    - Will have a savings assumption in the base case, plus additional EE based on cost.
    - Preliminary – within the state potential study 3 scenarios. This lines up to how Xcel approached it as well.
      - Program level – aligns with 2015 IRP order point. Base case.
      - Potential max as alternative
      - Mid-point in between those two.
  - Is pipeline cost included?
    - On a generic level they are – not site specific, costs to get gas to facility
    - Locations are not pre-determined, for IRP they consider size, type and timing
    - For that resource, location can be a cost driver.
    - Could be an argument for NTEC included in this bucket for optimization.
      - For this IRP, NTEC has been approved by commission so including it in the base case assumption.
  - Does what zone you are looking at impact anything?
    - For the large thermal resources, looking at zone 1
    - Modeling everything zone 1 for other assets as well. RFP's could look outside zone 1. No capacity congestion hedging tool in MISO right now.
  - Do you have a preliminary methodology for estimating interconnection capital cost for wind and solar?
    - Likely will using historical record with adjustments to fit current state
      - Still have some discussion on internal side to figure out how to apply this in modeling.
    - This is a newer problem of higher interconnection costs and more projects dropping out of the interconnection queue due to network upgrade costs, don't have a solution but something to flag
    - Want to see a larger conversation around the transmission cost assumption
  - Emphasize this approach of multiple open data sources is a great idea.
  - A participant would like to see company minimize reliance on third party data that will be confidential. If using this, would like to see it benchmarked against publicly available resources.

Load forecasting methodologies

- AFR process

    - Data gathering → data preparation and development → specification search → forecast determination → forecast review and verification → company review and approval
    - Is a separate docket, filed July 1st each year.
- They have incorporated conservation, EV, and solar impacts to the energy sale outlook.
- How do you do regression analysis? Do you use Metrics MD?
    - Set up in SAS for any mathematical modeling
    - **MP to follow up with more detail**
- Is the industrial model econometric or a projection?
    - Econometric based on pellet demand
- How is MP looking at electrification?
    - MP is watching general electrification trends, currently don't have a good data set/source to model with confidence in an IRP that meets integrity requirements for including in a AFR. At this point, aren't sure it can be included in IRP as a sensitivity.
    - **MP to follow up**
    - Currently only including EV's in the base and as sensitivities
- How does outreach/education of customers play into the model for electrification? Is there a forecast for how much the company plans to spend on promotion?
    - **MP to follow up**
    - For EE, modeled based on spending for rebates and education
    - Some happens through conservation programs, but it's unique because some of it is fuel switching. E.g., ASHP program targeted at electric heat customers, but submitted request to use with gas heating customers
- Can you give an on overview of how the AFR will fit into the IRP – are you making adjustments? (EE example)
    - The AFR load forecast will be the base case for the IRP
    - EE levels ordered in the 2015 IRP are already imbedded in the energy sales outlook, but also, there will be additional alternatives with incremental costs for higher EE savings that will be modeled in the expansion planning analysis.

List of futures and sensitivities

Futures: (base cases) - Futures are base cases that scenarios are run on top of

- MP has been ordered to use these as base cases and not sensitivities
- Questions/comments:
    - Are these all carbon related costs? Or are they accounting for other environmental regulation?
        - Environmental costs also include criteria pollutants (mercury was taken out)
        - **MP can provide the full list of externality values in the environmental cost column**
        - Regulatory cost – before 2025 assigning high- or low-end CO2 cost from externalities docket. After 2025 use the social cost of carbon.
    - What about coal ash compliance costs?
        - The same across all 5 State ordered planning futures.
    - How are they planning on modeling these costs?
        - Ordered to include them in the expansion modeling

    - How do you look at externality and regulatory values, and what is the preferred approach?
        - Not sure how EnCompass will handle including externality costs in the expansion planning
        - Stakeholder familiar with Encompass from other proceedings mentioned that Encompass might not be capable of optimizing an expansion plan based on State externality costs.
        - Regulation costs for carbon is incorporated as impact on dispatch in the modeling
        - Phantom costs – costs that impact decisions, but don't necessarily get accounted for in customer rates or energy markets.
        - **MP to think more on this and reach out to peers.**

Sensitivities: holding everything constant expect one factor - Provide some bounding and different perspectives on the modeling

- Slide 15 provides past sensitivities that MP has run – run 30-40 sensitivities across each future
- Questions/things to dig into more:
    - Could we set this up to see sub-optimal plans in the way that strategist allowed?
        - Might be able see that in the swim lane analysis.
        - The analysis could be completed in stages. For example, the 2013 IRP first evaluated retirements, than expanded list of potential alternatives, lastly the results were narrowed down into a handful of plausible swim lanes/generation portfolios.
            - We had to give strategist a limited set of alternatives, then based on those results would lock in retirement decisions and expand on alternatives available in the next phase of the analysis
        - Encompass is a new tool that needs to be explored further to see if a step process is required.
    - Lesson from last time – if we're more on the same page with the base case, the sensitivity analysis will be more meaningful.
    - **A participant would like more discussion on the amount renewable generation that can be built given the existing system**
    - **Resource/energy adequacy – want to know what would be changing in the modeling** – the methodology/mechanics of modeling
    - Boswell 3 and 4 economic offers versus the way it's currently offered – **interested in seeing that in some form.**
    - Seasonal load – increasing, or altered based on electrification?
        - Historically have had some load sensitivities – **MP can talk to load forecasters and bring back more info.** Otherwise, do high/low load outlooks.

Perspective on solar with storage

- The example shown was tot dispatched using the Encompass model.
- MP approach to modeling solar/storage is to have an energy resource available to meet peak demand with longer duration storage capability.

- DC coupled solar plus energy storage is different from AC solar with storage
    - Benefits:
        - less loss due to fewer conversion between AC and DC
        - Sharing AC infrastructure with solar panels, which reduces costs.
        - Opportunity to store the excess DC energy, which can then be discharged when needed..
    -
- How do you plan on modeling capacity accreditation for this technology?
    - MISO doesn't yet have clear rules or guidance – currently being vetted in the stakeholder process
    - MP has done a ELCC type study to determine a potential capacity credit value for solar/storage hybrid
    - Do we know what they are doing on that in Arizona?
        - Different because they don't have an organized market – they need to meet their own resource adequacy standards
- A participant asked about how this resource type would be "operationalized", in terms of when battery is charged/discharged?
    - Figure shows there are times when solar isn't used, and charges instead, even when solar is producing and energy is needed given the load curve.
    - Tried giving the model a 48-hour outlook on demand and energy prices but didn't change dispatch and charging pattern much. Better to optimize storage for tomorrow, rather than a couple days out.

Minnesota Power
2020 Integrated Resource Plan

Modeling Subcommittee Meeting 2
Thursday, May 28th 2:00pm - 4:00pm

Meeting Objectives:

1. Follow-up on questions from previous meeting
2. Minnesota Power presentation on planning futures being considered
3. Minnesota Power presentation on list of sensitivities for modeling

Agenda:

**** Please join meeting a few minutes before 2:00pm so we can start on time****

2:00PM	**WELCOME, INTRODUCTIONS, AGENDA REVIEW**
2:05PM	**REVIEW QUESTIONS FROM LAST MEETING**
2:30PM	**PRESENTATION AND Q&A: PLANNING FUTURES BEING CONSIDERED**
3:15PM	**PRESENTATION AND Q&A: LIST OF SENSITIVITIES**
4:00PM	**ADJOURN**

MINNESOTA POWER 2020 INTEGRATED RESOURCE PLAN

Modeling Subgroup Meeting 2

Thursday, May 29th 2:00pm-4:00pm

Via Zoom

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TOPICS FOR DISCUSSION WITH MN POWER ON IRP ANALYSIS

- Follow-up on questions from previous meeting
- Planning futures
- List of sensitivities

State Environmental Costs

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- Environmental Costs are presented in 2020 and 2030 values below, however values are escalated yearly for modeling use.
- Use of Low/Mid/High values is based on the Planning Futures ordered by the MN PUC in Docket DOCKET NO. E-999/CI-07-1199; E-999/DI-17-53.

Environmental Costs for Criteria Pollutants (Metropolitan Fringe)*

	SO2			NOx			PM2.5		
$/Short Ton	Low	Mid	High	Low	Mid	High	Low	Mid	High
2020	$4,999	$9,072	$12,452	$2,714	$5,889	$8,072	$7,097	$12,900	$17,691
2030	$6,136	$11,136	$15,285	$3,332	$7,229	$9,908	$8,711	$15,835	$21,715

Environmental Externality Values (Metropolitan Fringe)^

	CO			PB		
$/Short Ton	Low	Mid	High	Low	Mid	High
2020	$1.22	$1.69	$2.16	$2,625	$2,898	$3,170
2030	$1.46	$2.03	$2.59	$3,154	$3,482	$3,809

Note: All values are nominal dollars

**Commision Docket E999/CI-14-643, Criteria Pollutants - January 3, 2018*

^Environmental Externality Values, Docket Nos. E-999/CI-93-583 and E-999/CI-00-1636 - June 6, 2016

State CO2 Environmental & Regulatory Cost

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Environmental Costs for CO2*

$/Short Ton	Low	Mid	High
2020	$10	$28	$46
2030	$15	$42	$69

Regulatory Costs for CO2*

$/Short Ton	Low	Mid	High
2020	$5	$15	$25
2030	$6	$17	$28

Note: All values are nominal dollars

**Future cost of carbon, DOCKET NO. E-999/CI-07-1199; E-999/DI-17-53 - June 11, 2018*

Planning Futures Being Considered

	Carbon Dioxide (CO_2)					
	Prior to 2025		2025 and Thereafter		Other Pollutants	
Futures	**Environmental Cost**	**Regulation Cost**	**Environmental Cost**	**Regulation Cost (2025 Value)**	**Environmental Costs**	**Resource Adequacy Period**
Low Environmental Cost*	Low	-	Low	-	Low	Summer
High Environmental Cost*	High	-	High	-	High	Summer
Low Env/Reg Costs*	Low	-	-	$5/Ton	Low	Summer
High Env/Reg Costs*	High	-	-	$25/Ton	High	Summer
Reference Case^	Mid or High	-	-	$15 or $25/Ton	Mid or High	Summer
Current Customer Cost Perspective*	-	-	-	-	-	Summer
Low Environmental Cost	Low	-	Low	-	Low	Winter
High Environmental Cost	High	-	High	-	High	Winter
Low Env/Reg Costs	Low	-	-	$5/Ton	Low	Winter
High Env/Reg Costs	High	-	-	$25/Ton	High	Winter
Reference Case	Mid or High	-	-	$15 or $25/Ton	Mid or High	Winter
Current Customer Cost Perspective	-	-	-	-	-	Winter

** Required per future cost of carbon proceeding, DOCKET NO. E-999/CI-07-1199; E-999/DI-17-53 - June 11, 2018*

^ New future required per the Commission hearing on future cost of carbon on April 30, 2019. (Docket No. E-999/CI-07-1199, E-999/DI-19-406)

Electrification in MP's IRP

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- Electrification is a broad topic that covers many different economic segments
  - Delivered Fuels (Home/Business Heating, Agriculture, etc.)
  - Vehicular Fuels (Gasoline, Fleet Fuels, Mining, etc.)

- Electrification is difficult to forecast right now due evolving and developing technology
  - *MP does not have AFR quality data yet on the impacts of Electrification in each category*

- AFR2020 will include base assumptions for growth of residential EVs. The IRP modeling will include a High EV Sensitivity.

- MP Load Forecasting is investigating other data sources which could be used to develop a forecast for Electrification of Home & Business Heating Fuels. We will report back on this item at the next Modeling Subgroup Meeting.

Wind ITC Eligibility

Question: Is utility scale wind eligible for ITC after the PTC expires?

Answer: Somewhat, the ITC for Wind is scheduled to expire at the end of 2020.

<u>MP's Approach to modeling PTC/ITC in IRP Analysis:</u>

Wind

- 2022 – 2024: 60% PTC
- 2025+: No PTC

Solar and Solar/Storage*

- 2022 – 2023: 26% ITC
- 2024+: 10% ITC

December 2019 Extension of Wind ITC

If construction begins by...	The credit for large wind turbines is...
Dec. 31, 2018	18% of expenditures
Dec. 31, 2019	12% of expenditures
Dec. 31, 2020	18% of expenditures
Dec. 31, 2021	N/A
Dec. 31, 2022	N/A
Future years	N/A

** ITC for battery starts when 75% of energy used to charge is from solar. The ITC is then pro-rata between 75% to 100% of energy used to charge is from solar.*

Sensitivities for Consideration

Renewable Availability

Energy Market Interaction

Technology Innovations

Commodity Market Volatility

Energy Market Volatility

Fuel Market Volatility

Customer Outlook Uncertainty

Seasonal Demand Changes

Resource Adequacy

Energy Adequacy

Commodity & Energy Market Volatility

Biomass:

+/- XX% --- in progress, based on input from MP’s Fuel Group

Coal:

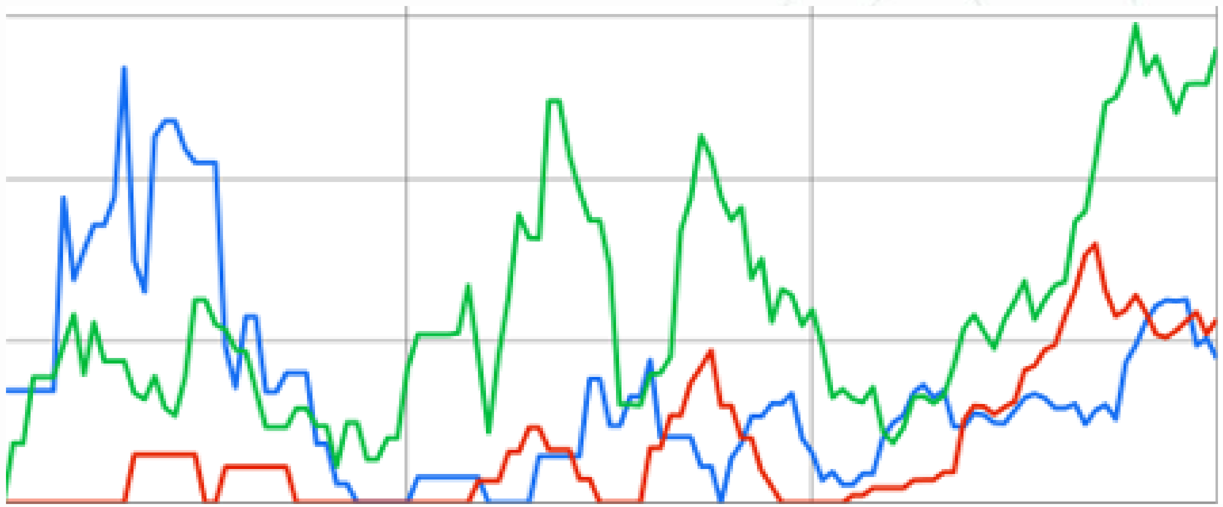
+/- XX% --- In progress, based of third-party study

Natural Gas:

-50%, -25%, +25%, +50%, 100%

Wholesale Electric Market:

-50%, -25%, +25%, +50%



Capital Cost Volatility for Alternatives

<u>Capital Costs for non-wind/battery storage/solar alternatives:</u>

+/- 30% -- Based on recommendation *from Purchased Third-Party Technology Estimate*

Innovations – Uncertainty in Technology Curves

Wind Cost:

Wind cost decline XX% from base assumption

Solar Technology Cost Curve Decline

Technology curve declines +/- XX% from the base assumption

Battery Technology Cost Curve Decline

Technology curve declines +/- XX% from the base assumption

Renewable Uncertainty

<u>Network Upgrade Cost for Renewable Interconnections:</u>

Lower than base assumption

<u>Renewable Energy Production</u>

Annual renewable energy production XX% lower than base

<u>ITC/PTC for Wind & Solar</u>

The ITC/PTC is extended XX years

Energy Market Interactions

- No sales into the market
- No sales and purchases in market
- Lower market access than what is allowed in base assumptions

Customer Outlook Variability

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- Lower customer demand
- Higher customer demand
- Energy efficiency high
- Energy efficiency higher scenario
- Residential “time of use” rate scenario

Seasonal Demand Changes

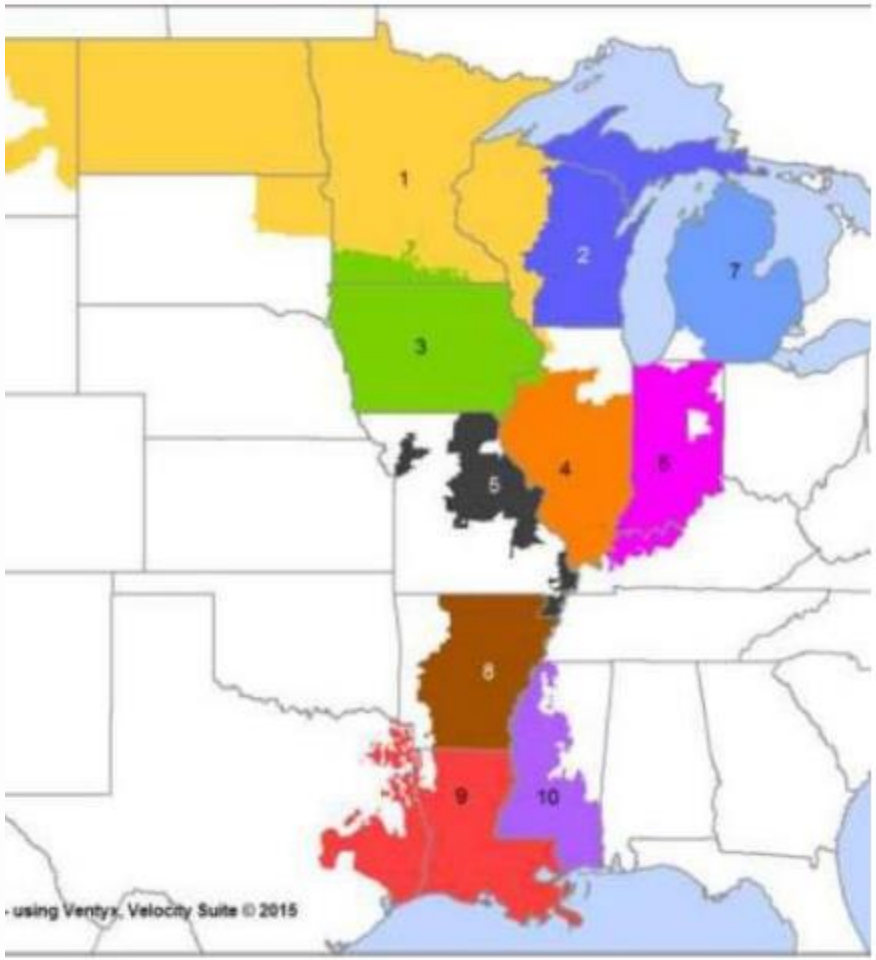
High DG Solar Growth

High EV Growth

High DG Solar + EV Growth

Resource Adequacy Uncertainty

- +/- 2% change in planning reserve margin
- +/- 2% change in MP's MISO coincident factor for peak demand



Next Steps

- Answer remaining open questions

- What do stakeholders want to hear about at next meeting?

- When does the subgroup want to meet next?

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MP IRP Modeling Subcommittee Meeting

May 28th, 2020

Via Zoom

Participants: John Christensen, Trevor Drake, Allen Gleckner, Chelsea Hotaling, Will Kenworthy, Taylor McNair, Evan Mulholland, Eric Palmer, Audrey Partridge, Anna Sommer, Kate Sullivan, Laurie Williams

Goal of this subgroup is for MN Power to get feedback from stakeholders on assumptions used in IRP modeling analysis

State Environmental Costs

- Use the metropolitan fringe data
- Discussion around how Strategist vs Encompass handle externalities
    - They are added at the end, but resource selection is not influenced by externalities
    - Encompass only comes up with one plan
        - MP can attempt to come up with suboptimal plans, but this will differ from Strategist
        - Option in encompass to include externalities in resource function - potential issue with that because you won't get a realistic dispatch result
    - In order to capture the impacts of these scenarios we need to specify a broad range of portfolios

Carbon regulation penalties

- Two types of costs: Environmental costs and Regulatory costs

Planning futures being considered

- Required to run 5 of the cases
- Looking at winter and summer peaking

QUESTIONS:

- Operationally, how are you looking at summer and winter peaking loads?
    - MISO doesn't currently have a winter adequacy requirement so it would be applying summer reserve margins to winter peaking
        - Tradeoff between simplicity and accuracy
        - **Flag for more conversation**
    - Same resource accreditation
    - Is this a sensitivity?
        - Layered in as a base assumption

        - Is this an on/off switch? Or should we treat it more like a sensitivity?
        - **Flag for more conversation**
- Do you have a sense of how much of a difference these considerations make?
    - Haven't tested anything yet – still setting Encompass up
    - Are you running all the sensitivities on these futures?
        - Yes, purchasing forecasting information from someone else

Electrification in the IRP

- Difficult to forecast due to developing technologies
    - Current data does not meet AFR quality that will hold up under regulatory scrutiny
    - Looking at other data sources that can be used to forecast electrification
        - **will report back on this**
    - Include reference to the carbon limit set by MN GHG goals

Wind ITC Eligibility

- Not including ITC in the modeling after PTC expires after 2024 for wind

Sensitivities

- Commodity and energy market volatility
    - Biomass, coal, NG, and wholesale electric market
    - Independent sensitivities

  QUESTION:

    - How do different resource decisions change sensitivities – end with one portfolio?
        - Correct
        - What if instead you had multiple portfolios and assed each of them?
            - Plan is to do both
- Capital cost volatility for alternatives
    - Can you benchmark this against other resources, like the ATB?
    - Estimate is based on our region
- Innovations – uncertainty in technology curves
    - Certain that wind costs will decline – less certain about solar and battery technology
- Renewable uncertainty
    - Renewable energy production percentage – can you model different weather years?
        - Not sure how they are going to model this yet – use a previous methodology that tries to capture the typical months use. MP has done some risk analysis – its not a random number, given what they know 10% variation is reasonable
        - Open to discussion on this topic
        - Need to balance the goals with the time invested in this sensitivity

    - Working on finalizing base assumption for network upgrade cost for renewable interconnections
        - will ultimately try and model it at a $/kw
        - **stakeholders want to review this number**
        - MP does plan on modeling solar with zero interconnection cost
- Energy Market Interactions
    - This sounds reasonable, but need time to see the numbers and know how its operationalizing in the model
- Customer Outlook Variability
    - How are you thinking about customer demands given the uncertainty today?
        - Can speak to what MP has done in the past – load forecasters are working on impacts since COVID
        - Related mostly to industrial customers
        - Traditionally it has been a 10% swing of total load
        - Will have more info once the AFR is published
- Seasonal Demand Changes
    - High DG solar growth, high EV growth, high DG solar and EV growth
    - Do you know how you will forecast these?
        - Doing it as part of the AFR – using social/economic data to determine rate of adoption
- Resource adequacy uncertainty
    - MISO is moving to resource accreditation for renewables and thermal units – how will this impact MP?
        - Reclassifying planned outages as forced if not planned far enough out – MP has already taken this into account, and it won't change much with resource adequacy
    - How is energy adequacy captured in the sensitivities?
        - Currently it is a placeholder
        - Heard of people transition away from traditional capacity adequacy and looking at it as energy adequacy
            - Open to feedback on this

Minnesota Power
2020 Integrated Resource Plan

Modeling Subcommittee Meeting 3
Wednesday, July 29th 1:00pm - 3:00pm

Meeting Objectives:

1. Review process objectives
2. Continue to develop a shared understanding of the sensitivities that MN Power has put forth and discuss barriers, opportunities, and recommendations
3. Address and discuss stakeholder concerns

Agenda:

**** Please join meeting a few minutes before 1:00pm so we can start on time****

1:00PM **WELCOME, INTRODUCTIONS, AGENDA REVIEW**

1:05PM **PROCESS OVERVIEW**

1:15PM **TOPIC DISCUSSIONS**

- Conservation Base Assumptions and Alternatives
- MISO Interconnection Cost for New Wind
- MP's Approach to Modeling New and Existing Wind & Solar in IRP
- Follow-up on Open Questions

3:00PM **ADJOURN**

MINNESOTA POWER
2020 INTEGRATED RESOURCE PLAN

Modeling Subgroup Meeting 3

Wednesday, July 29th 1:00pm-3:00pm

Via Zoom

Topics for Discussion

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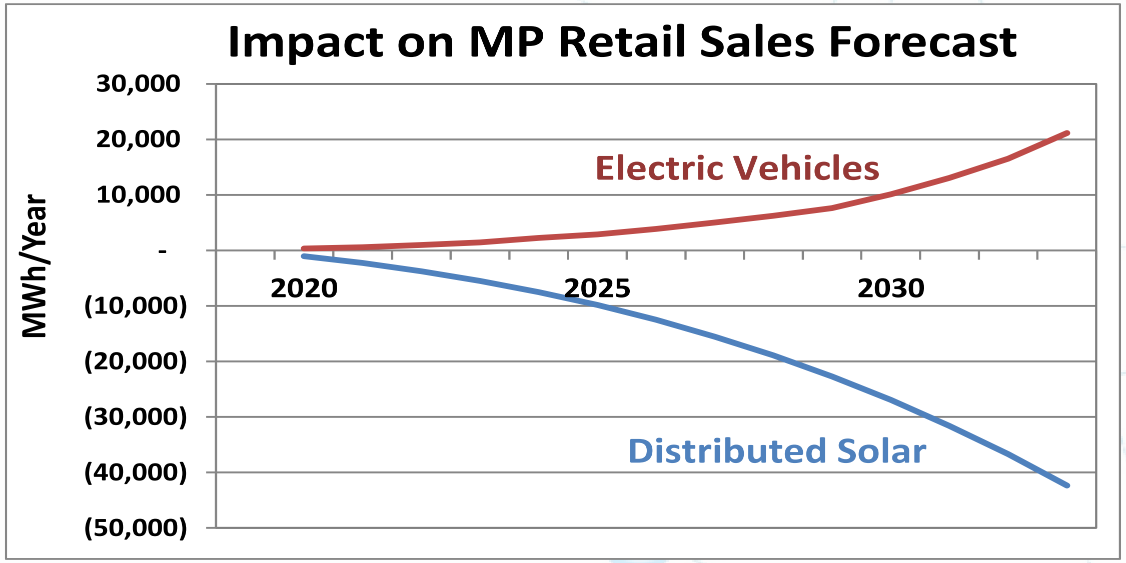
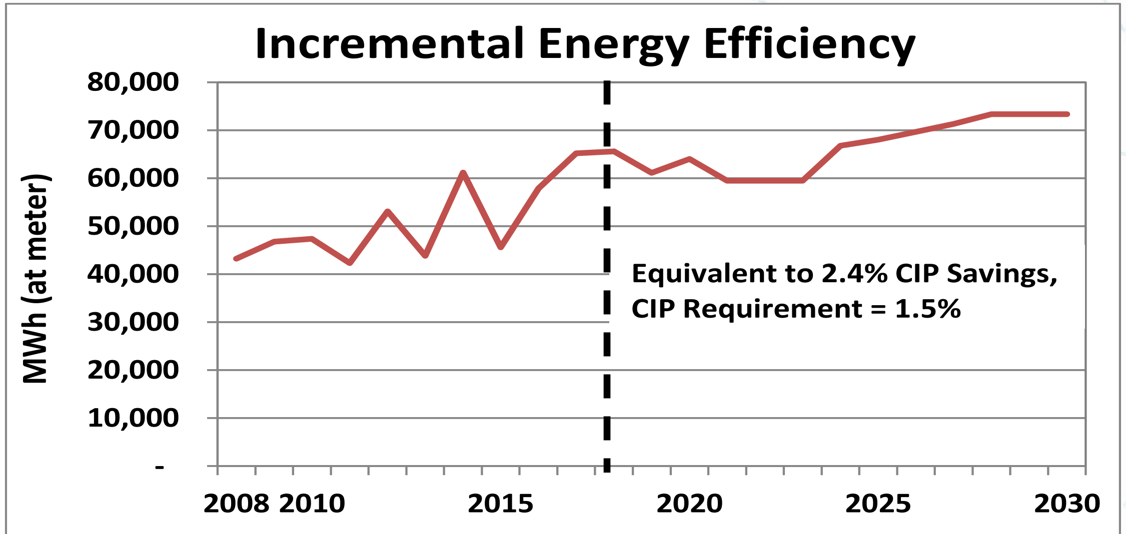
1. Conservation Base Assumptions and Alternatives
2. MISO Interconnection Cost for New Wind & Solar
3. MP's Approach to Modeling New and Existing Wind & Solar in IRP
4. Follow-up on Questions/Comments

EE & Technology Outlooks Used in IRP Load Forecast

- **Conservation**
  - Assumptions are consistent with updated CEE potential study, CIP Triennial, & IRP
  - EE included in residential, commercial, public authorities, & resale models
- **Electric Vehicles**
  - Only residential adoption (fleet vehicle inclusion being monitored for future filings)
  - Currently serving 135 vehicles (0.12% penetration)
  - Forecasting about 4,160 vehicles (3.7% penetration) by 2030
- **Distributed Solar**
  - Modeled residential & commercial
  - Currently about 3.3 MW of <40 kW installations
  - Projecting 27 MW of new installed capacity (~30 MW total) by 2030
  - New installations will displace about 27,000 MWh (1.2%) of MP sales to residential & commercial classes





Electric Vehicle Scenarios Planned for IRP Analysis

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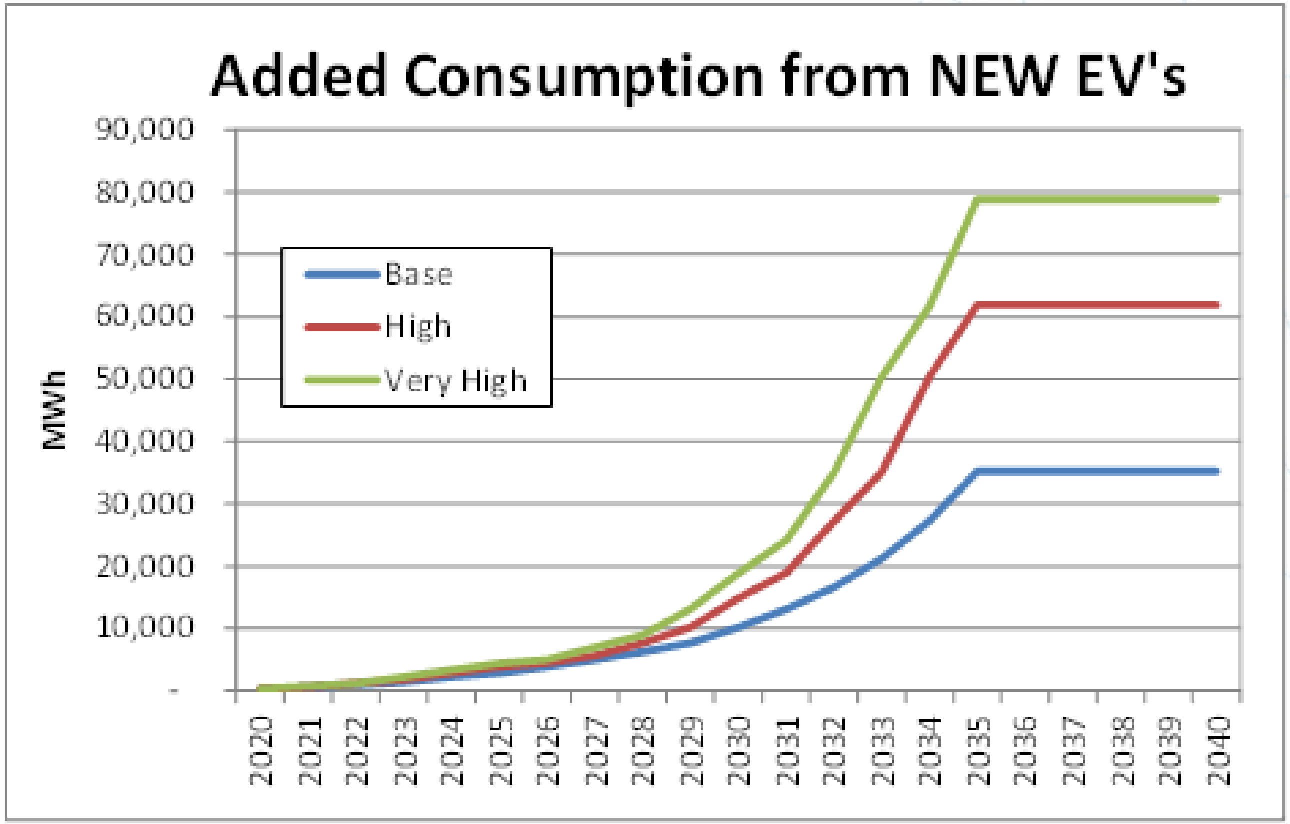
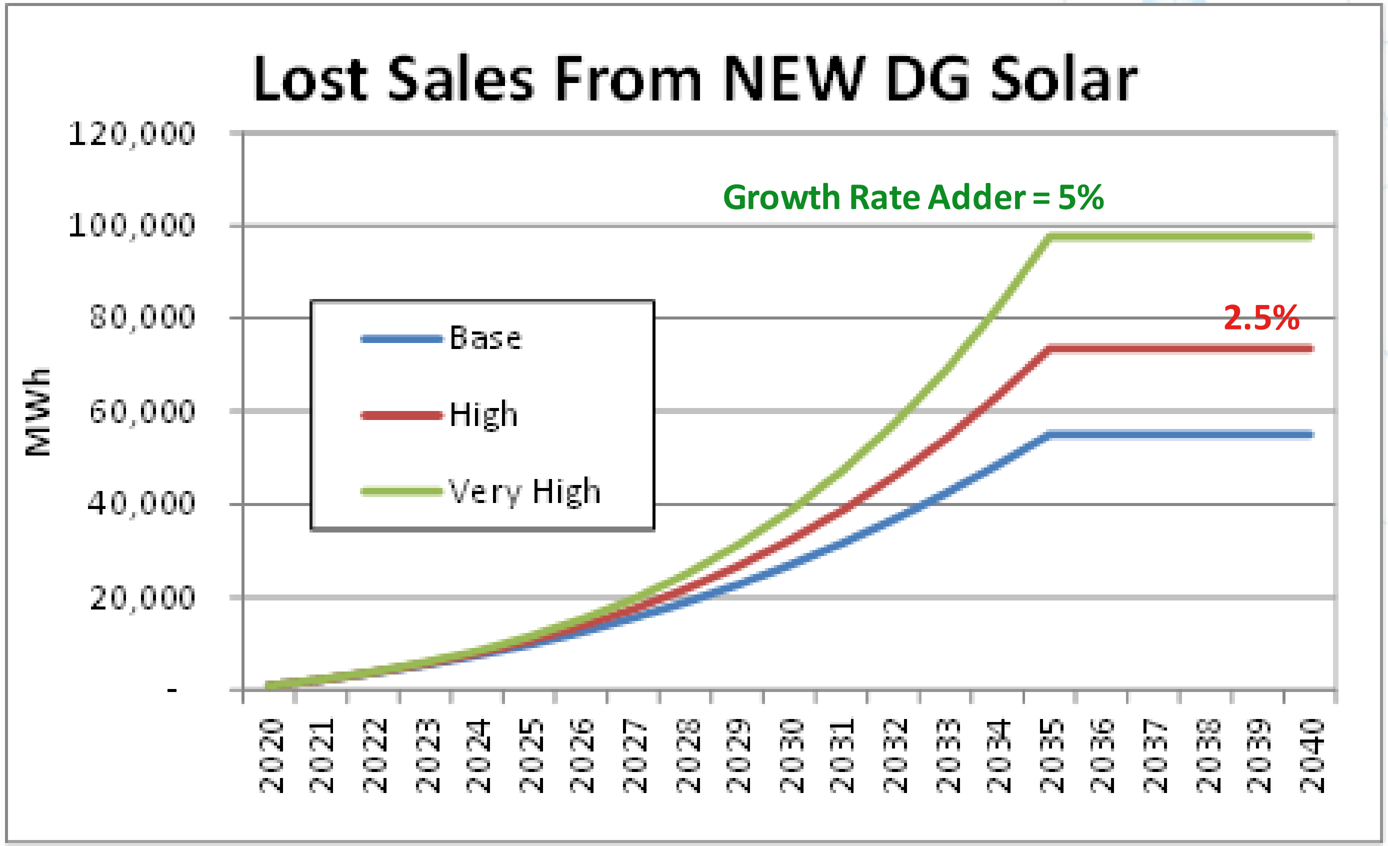
- **Base Case:**
  - ~1,300 EV's on MP's grid by 2025, 14,000 by 2035
  - Saturation lags Overall US by 6 yrs.
- **High EV Scenario:**
  - ~1,700 EV's on MP's grid by 2025, 25,000 by 2035
  - Saturation initially lags US by 6 yrs, but accelerates. By 2035, MP is only 3.5 yrs behind US.
- **Very High EV Scenario:**
  - ~1,900 EV's on MP's grid by 2025, 31,000 by 2035
  - Saturation initially lags US by 6 yrs, but catches up. By 2035, MP is only 2 yrs behind US.



DG Solar Summer Daily Peak & Sales Impact

<u>DG Solar Summer Day Peak Hour</u>

- Base Case
  - 2025 = 3 MW
  - 2035 = 14.5 MW
- High Case
  - 2025 = 3.2 MW
  - 2035 = 19 MW
- Very High Case
  - 2025 = 3.5 MW
  - 2035 = 24.5 MW



Conservation Scenario for IRP

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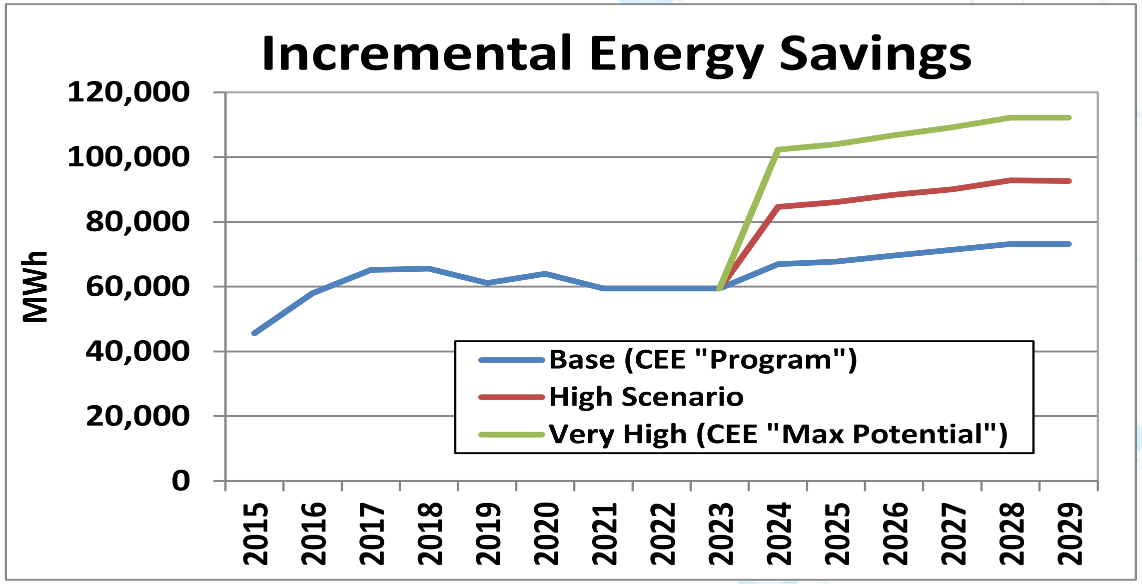
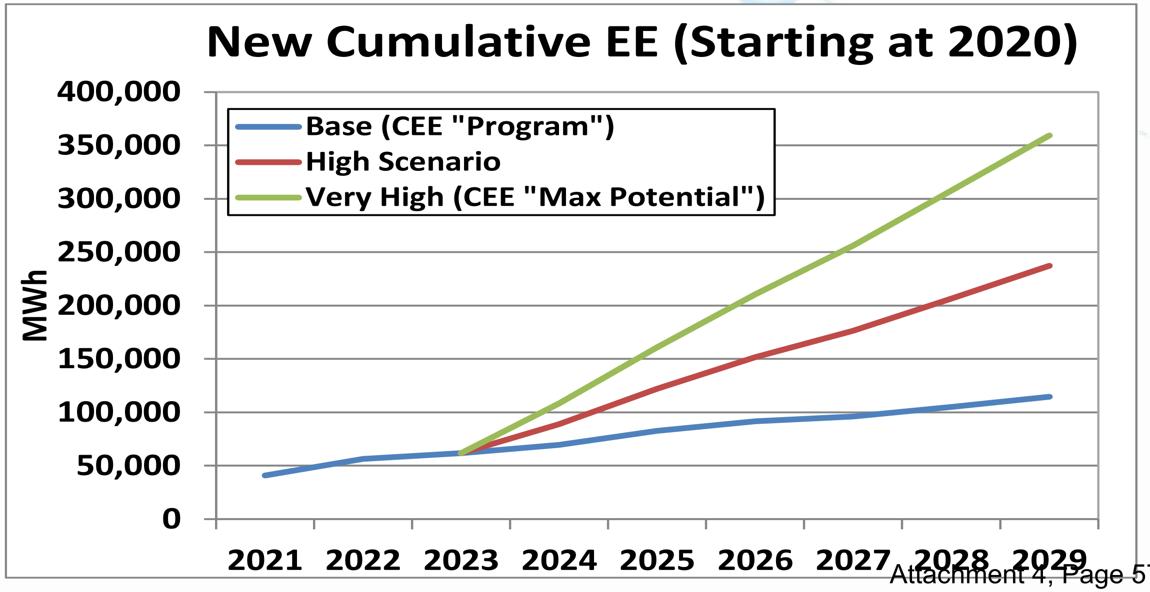
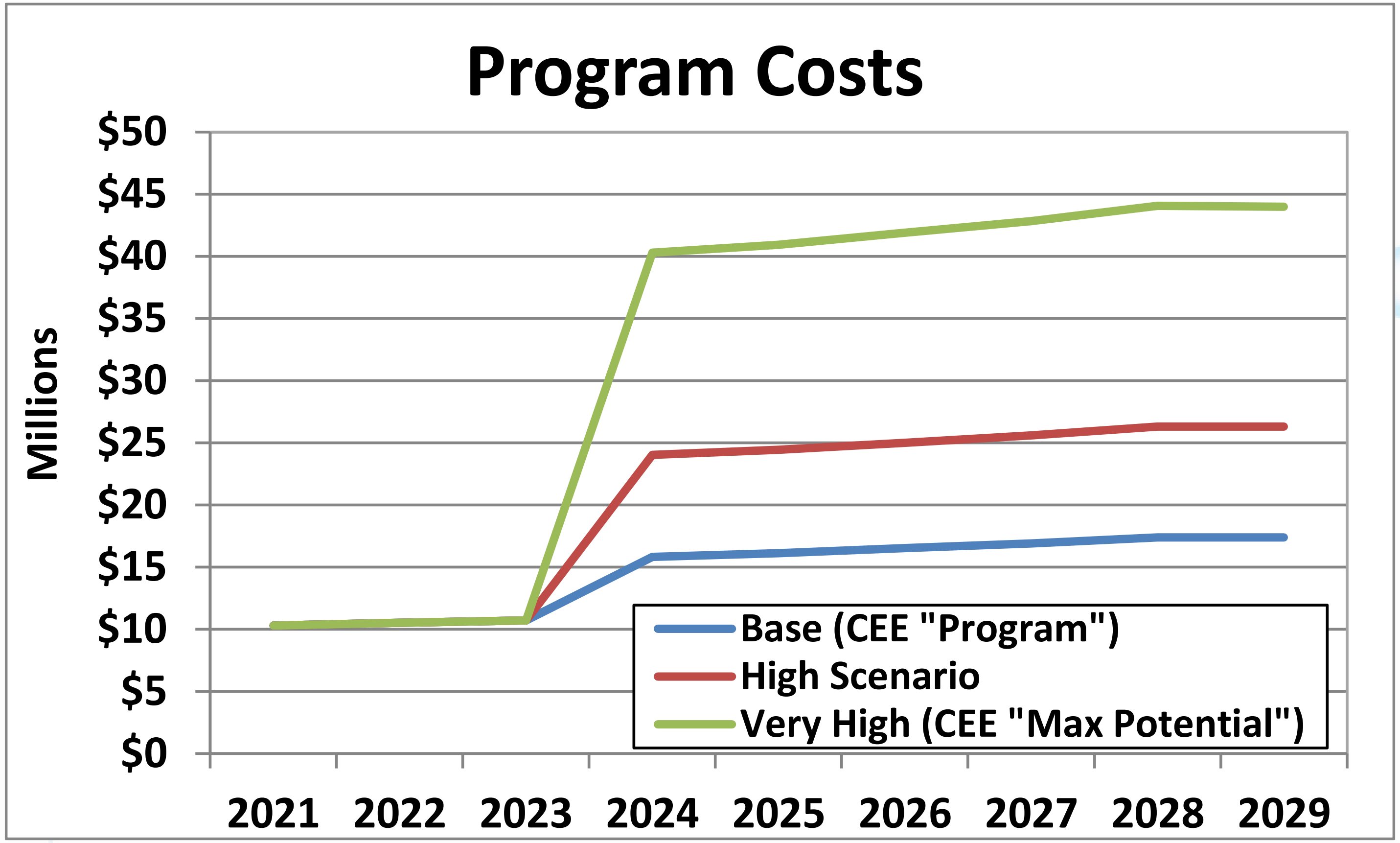
- MP Plans to evaluate the following conservation scenarios in the IRP Analysis
- The incremental energy savings above base will be included as alternatives.
  - High Scenario & Very High
- Base case (CEE “Program”) and sensitivity outlook developed using CEE’s Potential Study working papers, updated per sales outlook and CIP exemptions





Conservation Program Costs

The incremental program costs above the Base (CEE "Program") define the costs for alternatives considered in the analysis.



Transmission Interconnection Costs - Methodology

- MP's approach uses historical costs for generation projects in MISO Interconnection Queue
  - All the projects in the West Cycles (Feb '16 -> April '18) were included
  - Projects were grouped by "fuel type" – i.e. Wind, Solar, etc.
  - Network Upgrade Costs were divided into three buckets:
    - **C1**: Base MISO (POI Substations, Thermal Upgrades, etc.)
    - **C2**: Backbone Upgrades (Base Case Upgrades, MWEX Upgrades, LPC, etc.)
    - **C3**: Affected System Upgrades (PJM, SPP, etc.)
  - Projects' cost impacts to the "buckets" were weighted by the size (MW) and the "depth" into the DPP Process obtained

Phase 1	Phase 2	Phase 3	GIA or Complete
6%	14%	29%	51%

New Renewable Alternative Interconnection Costs

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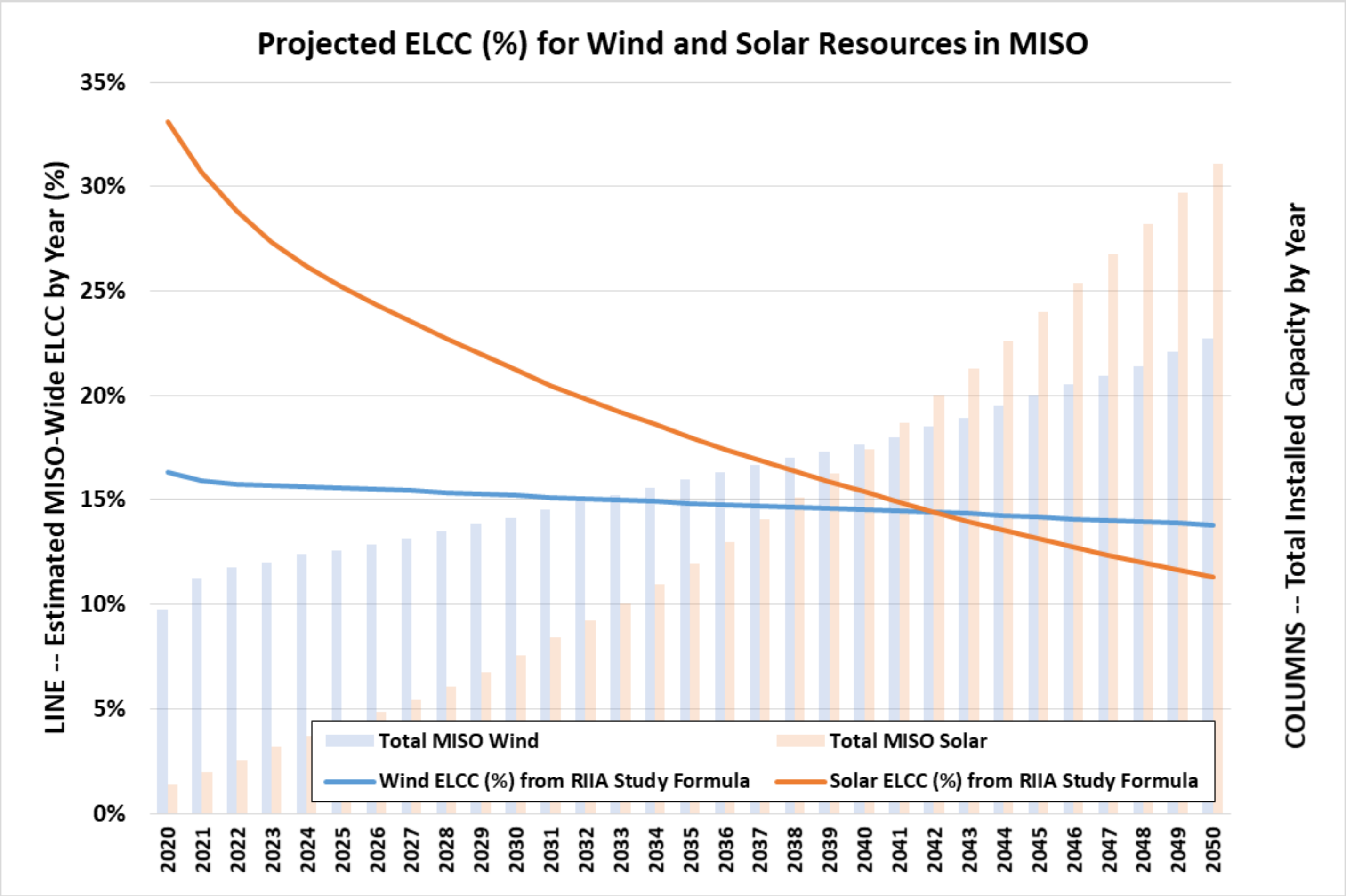
(2020 $)	Wind	Solar*
C1: Base MISO	$111/kW	$63/kW
C2: Backbone	$232/kW	$3/kW
C3: Affected Systems	$148/kW	$126/kW
Base Case Interconnection Cost	**$491/kW**	**$192/KW**
Low Interconnection Sensitivity (No C3)	*$343/kW*	*$66/kW*

- Note – We are assuming Energy Storage Systems can be sited where the transmission system requires little to no upgrades (i.e. BTMG, Hybrid Interconnection, Combination with Renewables), thus no interconnection costs assumed.

** The solar costs above will apply to Generic Solar only. Net Zero Solar will be shown as a $0/kW interconnection in both the "Base Case" and the "Low Interconnection Cost" Sensitivity.*

RIIA ELCC Formulas & IHS Spring 2020 Forecast

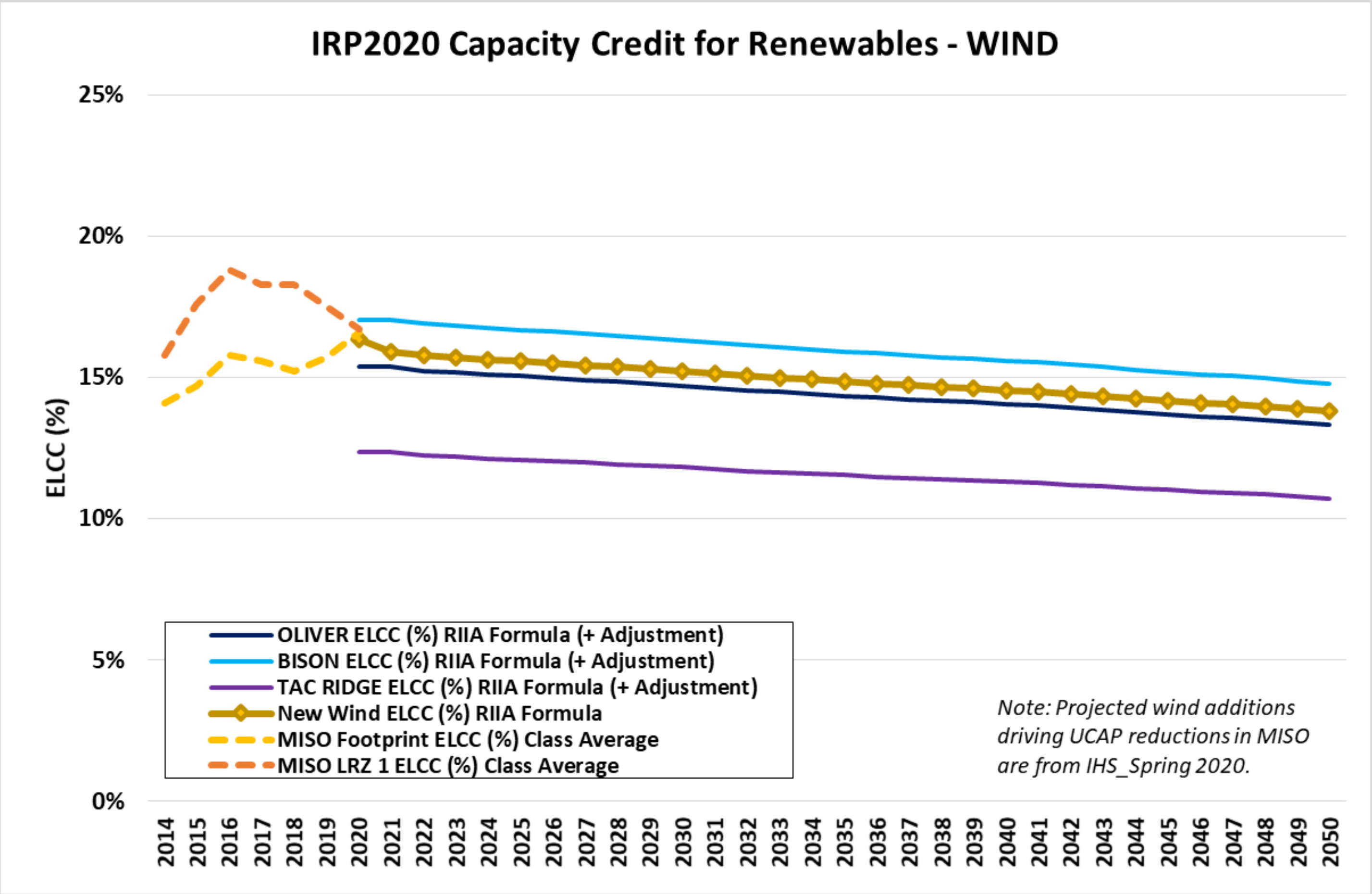
- MISO published formulas for approximating the Effective Load Carrying Capabilities of Wind and Solar based on Installed Capacity as part of RIIA.
- Inserting the projections for installed Wind and Solar in the MISO footprint from the IHS Spring 2020 forecast provides a projection of future ELCC values.
- MISO is developing plans for a Solar ELCC as part of the RAN initiative. We expect that implementation of the plans will occur over the next 3-5 years.



ELCC Projections for New and Existing Wind

MP's Plan for Accredited Capacity Value for New & Existing Wind

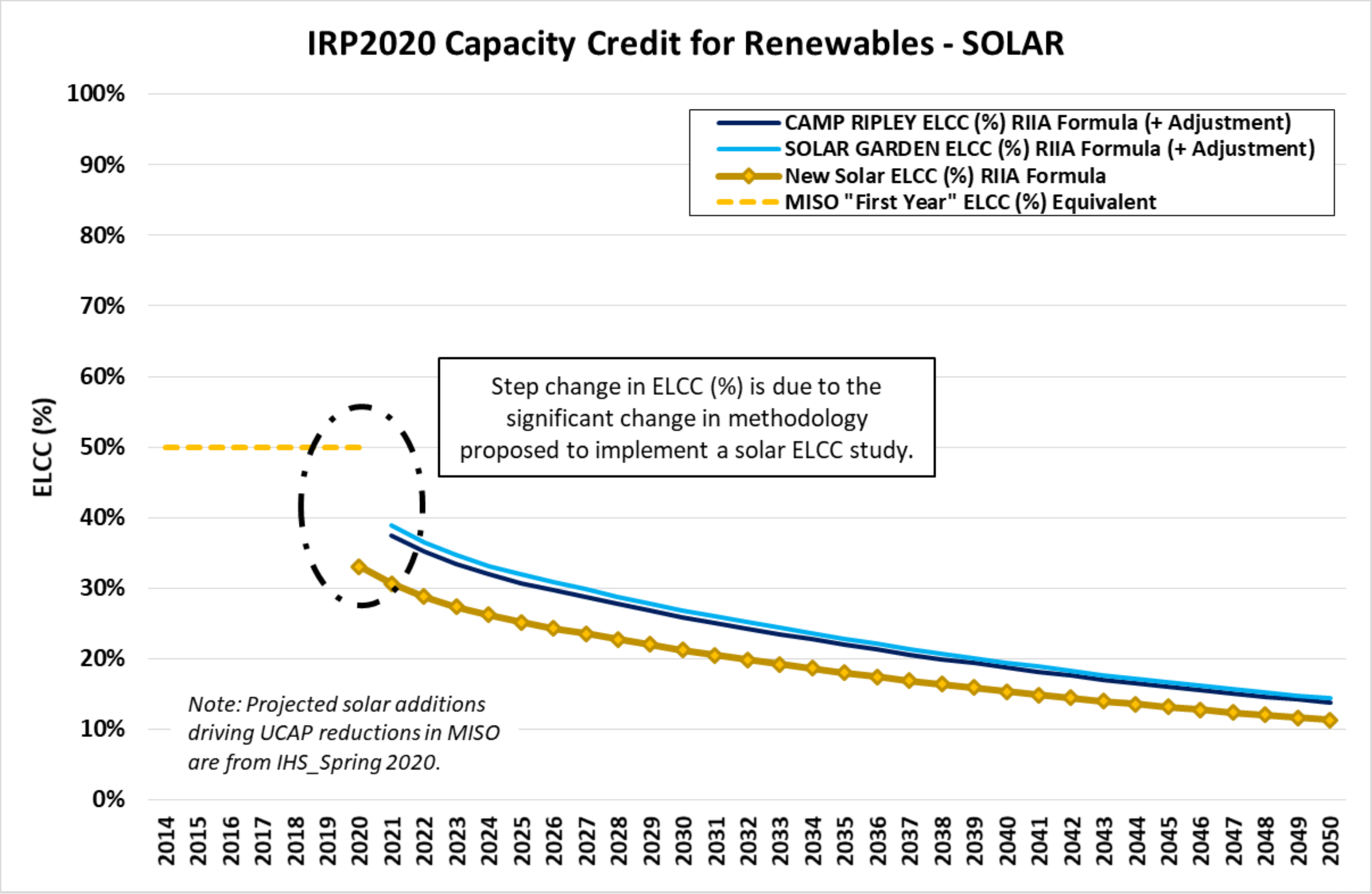
- MP's ND wind typically performs near or above MISO class average
- We plan to use historical performance to adjust the RIIA ELCC formula projection for each existing farm.
- New wind farms will use the RIIA formula based projection.



ELCC Projections for New and Existing Solar

MP's Plan for Accredited Capacity Value for New & Existing Solar

- MP's solar facilities have historically performed better than the MISO "First Year" accreditation value due to higher generation levels during MISO peak ("time zone benefit").
- We currently plan to adjust our existing solar facilities to reflect the "time zone benefit", will continue to monitor RIIA and RAN initiatives.



Approach to Modeling Existing ND Wind and New ND Wind

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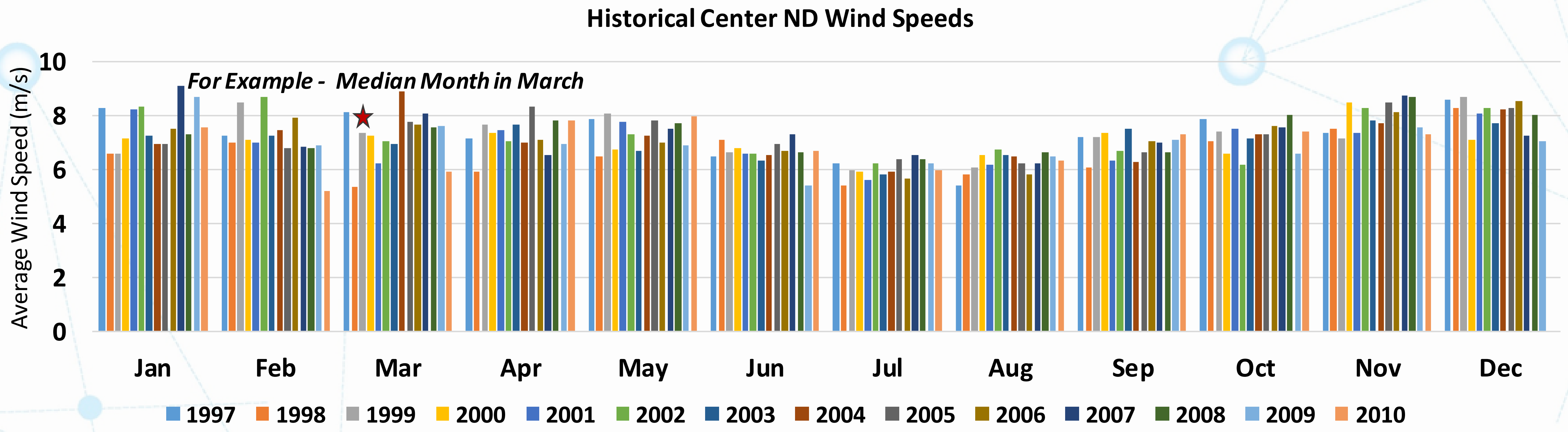
Hourly Wind Profiles for Center ND from 1997 to 2010 → Selected Monthly Wind Profile that Represent Median Wind Speed Conditions → Convert Wind Speeds into Energy Production → Adjust Output to Realistic Annual Production*

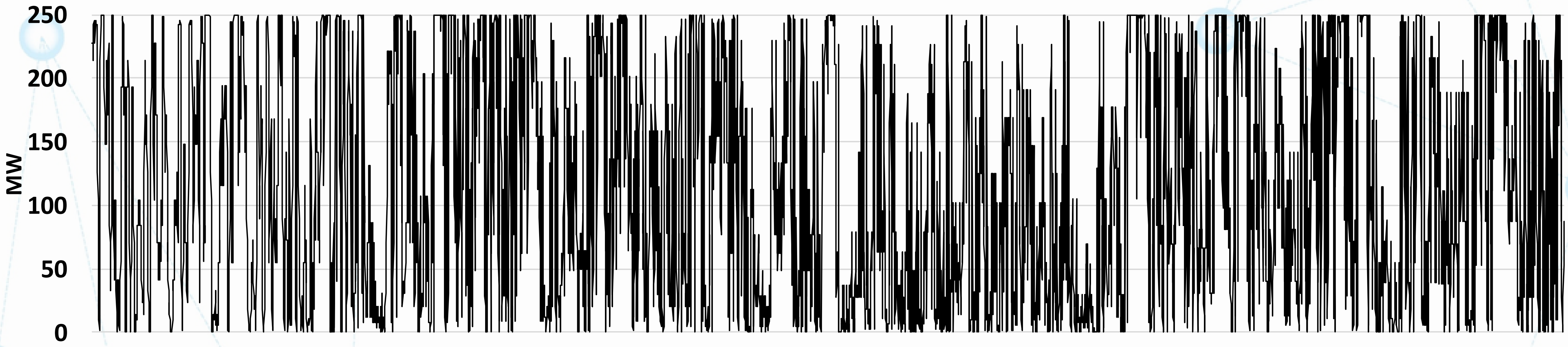


*Adjustment accounts for wind quality, wake effect, and forced and planned outages.

Approach to Modeling Nobles 2 and New MN Wind

Gathered MERRA^ Data that Aligned with Periods Modeled for ND Wind → Scaled Wind Speeds to Nobles 2 Hub Height → Convert Wind Speeds into Energy Production → Adjust Output Realistic Annual Production*

Projected Nobles 2 Hourly Generation

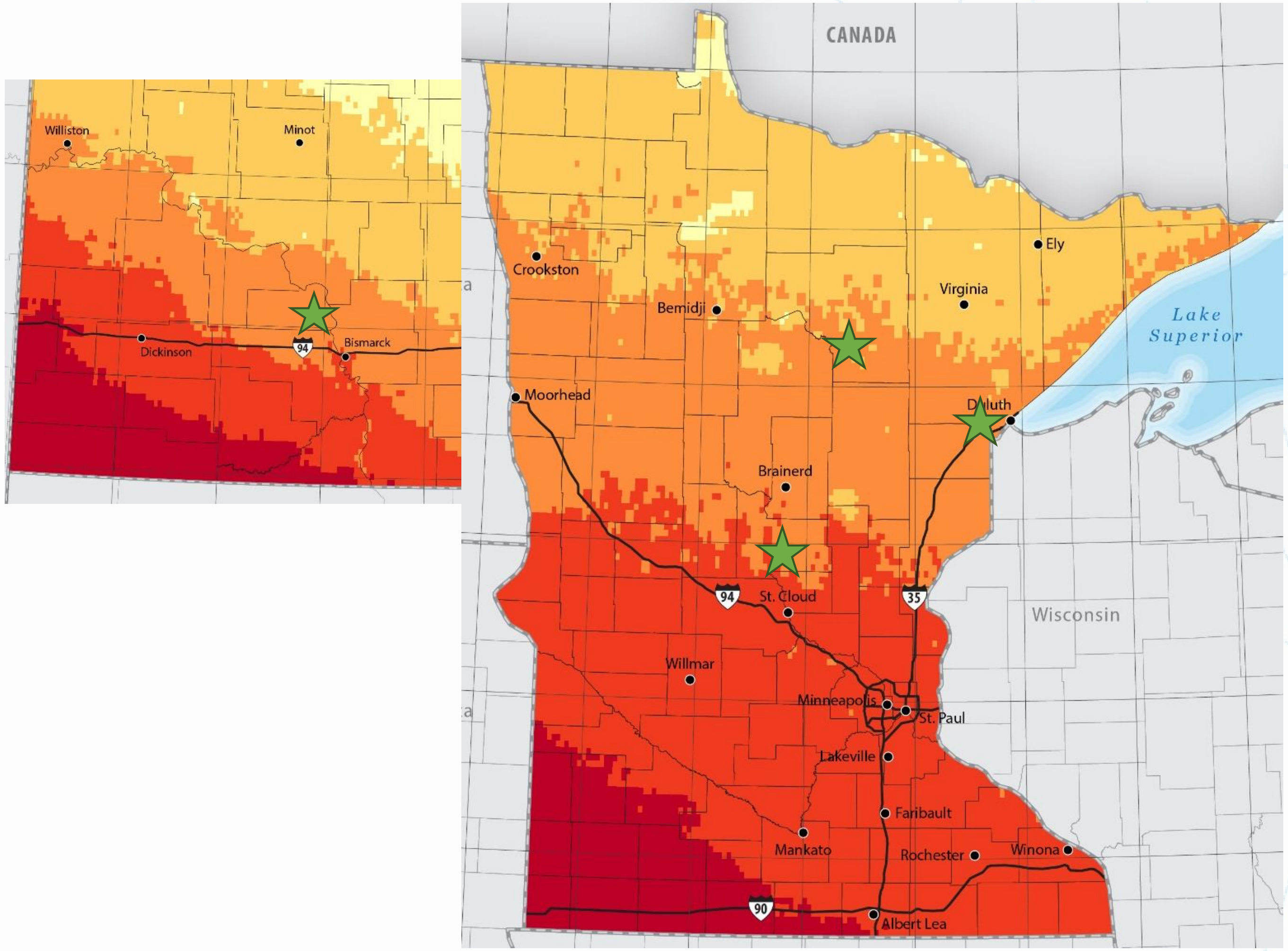


^ The Modern-Era Retrospective analysis for Research and Applications (MERRA) is a dataset released by NASA. The data set spans the period 1979 through February 2016.

**Adjustment accounts for wind quality, wake effect, and forced and planned outages.*

Approach to Modeling New Solar Facilities

- We used the NREL SAM tool (with SolarAnywhere data) to model 100 MW single-axis tracking facilities at four sites as 8760 datasets:
  - St. Louis County, MN (Duluth Area)
  - Itasca County, MN (Grand Rapids Area)
  - Morrison County, MN (Little Falls Area)
  - Oliver County, ND (Center Area)
- The SolarAnywhere data was selected because of the inclusion of snow data which is vital for solar modeling in MN and ND.
- We plan to use some or all of these profiles in Encompass for new solar resource alternatives considered in the IRP.



Response to Questions/Comments Since Last Meeting

- **Modeling winter resource adequacy requirements**
  Response: MP will monitor in the load forecast used for the IRP the difference between summer and winter peak. MP will return if the differential warrants a dual season approach to resource adequacy and address with stakeholders. MP is also monitoring MISO's RAN and RIIA and any outcomes that could impact modeling resource adequacy.

- **Not all sensitivities listed were discussed from slide 7**
  Response: MP assumes this is in reference to the "Energy Adequacy" sensitivity. MP will return to the stakeholder group if the Company decides to move forward with including "Energy Adequacy" as a sensitivity in the IRP analysis.

- **Using technology curves and incorporating future cost declines for wind, solar and batteries**
  Response: MP will commit to showing the capital cost curves for wind/solar/storage at the next modeling subgroup meeting. MP will also review the IPL IRP PowerPoint and will return with our perspectives.

- **Network interconnection cost issue for wind/solar…assumptions should be grounded is reasonable data.**
  Response: Agree, and as discussed today, MP's approach is to use public data from the MISO interconnection process

- **Renewable energy production uncertainty…recommend a weather variability modeling approach rather than a static percentage discount on energy production. NREL data could be used to develop this.**
  Response: Agree, this could be a fine tuner. MP will need to evaluate if there is adequate time to include in the IRP analysis. MP's perspective this is a lower priority adjustment for this IRP.

Response to Questions/Comments Since Last Meeting

- **Limits in market access used in the "base assumptions" are supported as to why those limits were chosen are reasonable.**
  Response: Would like to explore perspectives on how other utilities are approaching market access and discuss reasonable sensitivities.

- **For EE and TOU…magnitude of variation from the "base assumptions" will be important, as well as design details of the EE and TOU sensitivity.**
  Response: EE we discussed today. MP will expand on the TOU sensitivity details at the next stakeholder meeting.

- **Resource adequacy uncertainty…use historical data to determine the PRMR and Coincident Factor range.**
  Response: Agree, this could be a fine tuner. MP will need to evaluate if there is adequate time to include in the IRP analysis. MP's perspective this is a lower priority adjustment for this IRP.

Next Steps

- When should we meet next?
- Follow-up on technology curves for wind/solar/storage and TOU sensitivity.
- Other follow-up items?

MP IRP Modeling Subcommittee Meeting

July 29th, 2020

Via Zoom

Participants: John Christensen, Eric Palmer, Will Kenworthy, Audrey Partridge, Trevor Drake, Kate Sullivan, Alissa Bemis, Allen Gleckner, Andrew Twite, Anna Sommer, Chelsea Hotaling, Even Mulholland, Laurie Williams

Process Discussion:

- What is the purpose of the stakeholder workshops?
  - Looking for feedback to take into consideration for the modeling instead of trying to have debates through IR and comments/reply comments
  - Share ideas and identify opportunities to improve or change
- Is that what the stakeholders expected out of the workshops?
  - Yes, because the group is cooperative/collegial – as such, don't need a ton of structure
  - Goal was collaboration instead of mediation
    - Wanted to create understanding with stakeholders
    - This is reducing the number of discovery questions that are usually asked by pax

Presentation:

EV Scenario Planned for IRP Analysis

- Base case assumes current rate of saturation (lags US overall by 6 years)
- High/Higher scenarios: saturation rate increases (still lag US overall but by fewer years)
- Have you looked at different load shapes for EV? What are you looking at for charging patterns?
  - Don't have percentages, have seen shapes that show primarily evening charging, with scattered charging throughout the day
  - Fresh Energy is interested in this – **MP to follow up with hourly load profiles**
  - It won't be a huge driver of the shape in general

DG solar

- Numbers presented are the impact on summer day peak – don't have installation rate **(MP will follow up)**
- How did you drive these forecasts?
  - Base rate continues current, for high and very high they were accelerated

  - Certain propensity for customers to have cash to spend on this which is why there is a non-linear graph
- Is this the amount online during the summer day peak? Does that tie back to the amount online in the previous scenario?
  - Yes.
- Is this how other utilities are approaching this?
  - Depends on geography – but MP is wondering how they would compare
  - Hard to say based on these numbers, would be better to compare sales
  - Some have started using a cash flow model to asses rooftop solar adoption
- **MP will follow up on methodology for DG solar**

Conservation scenarios

- High scenario is a blend between very high and base.
- What percent of sales do these scenarios reflect?
  - Base case represents close to 2.4% which is in line with order point from 2015 IRP
  - **MP to follow up on percentages.**
  - Rough estimate is 3-4% in higher scenarios.
  - The 3-4% does not include CIP exempt customers (if it did it would be really high)

Conservation program costs

- Incremental increase in program costs from the base
- Adding $10 mil from the base case for the high and $15 mil for the very high
- These costs and potential are based on the CEE study
- Why are the cost curves so "lumpy?"
  - 2021, 2022, and 2023 are based on current triennial and in 2024 it will be set with the next triennial, which is why it jumps.
- Would the step changes influence how the model chooses EE, because it's a big jump in cost?
  - It is more of a program cost over a period of time, not all in the first year.
- Can MP provide more info on the CIP program and how it will be incorporated in the model?
  - **Yes, MP to follow up**
  - Similar to how Xcel set up the cases for CIP

Follow-Ups:

- Would like to see load profiles for EV's.
- Installation rate for DG solar.
- How you're going to put this information (e.g., EE bundles) into Encompass.

Transmission and interconnection costs

- MWEX == MN-WI Exchange

- LPC = Local Planning Criteria
  - IN MN, the LPC tripping, is that mainly GRE?
  - It varies. We've seen different costs pop up at different times. GRE related to loss of Coal Creek is the biggest one.
- Affected system upgrades – mostly SPP
- Trying to find a way to include projects in the interconnection queue and the costs associated with them (include the depth of the queue)
- Looked all the projects that have been studied in the west study
  - If a project dropped out at phase one, costs for the project were phase one costs
  - If a project was completed, the completed costs were counted
  - Did this to only count projects once based on the last cost estimate that was produced for that project
- Percentages in the phases was based on the MISO OMS Survey, in which they give a percentage to resources that aren't yet completed, based on their analysis of their own queues and success rates.
- Are you saying phase one cost estimates go into the calculations?
  - Yes - These earlier phases often weed out projects where costs are super high (and they are less economical), and in the later phases they are much lower costs - if we're going to accelerate the rate of adoption we are going to have to start digging into the phase one and two projects which is why they are included (although they are weighted less)
- Wind and Solar each have different interconnection costs on a $/kw bases
  - Think it is associated with less solar overloads
  - See very similar costs in the affected systems
  - Base interconnection cost: wind: $491 – solar: $192 kw
  - Will have hybrid solar included in the modeling – won't have interconnection costs
  - Net-zero solar = "surplus" according to MISO
- How much net-zero are you planning on including?
  - Still doing some analysis in terms of how much can be placed near existing assets, and that would be used at the baseline. Will still do it in blocks, and that won't be site specific. Looking at places where we already have interconnection rights.
- Could you potentially do a C1 interconnection cost that's lower in the future, rather than what it is right now?
  - Trying to look at where those costs go – they don't disappear, they just get put in a different bucket. So even if MISO were to build more lines to reduce interconnection costs, MN Power's customers would still get hit with the cost of those lines.
- Wouldn't some options allow the system to be more optimizes, so result in lower costs, rather than assigning costs specifically to specific new resources? Couldn't then the cost be less, while acknowledging everybody will still pay for new transmission?
  - **Willing to continue to discuss this**.

- Has MP done any analysis on what MVP costs historically looked like to use as a benchmark to check the reasonableness of these assumptions?
    - **MP can take a look at this**
    - Laurie willing to look at this and provide feedback, based on what has been elsewhere

ELCC's and Renewables

- ELCC = effective load carrying capacity, used to determine how much capacity they're given in assessing how much capacity is available to ensure adequate supply.
    - Doing an ELCC for wind for the last few years, don't have something for solar because there hasn't been a high enough penetration
- RIIA – MISO's Renewable Integration Impact Assessment, looking at integration of renewables and concerns on MISO system, including resource adequacy.
- RAN = Resource Availability and Need. One of the action items is to develop and implement an ELCC for solar.
- Trifecta of RIIA, RAN, and IRP. Market outlook that MP used for market prices also includes projections on installed capacity. Took those and plugged them into MISO formulas to produce the two curves on the chart on slide 10.
- If MISO implemented a solar ELCC, expect to see a 30-35% footprint – wind is not expected to change much over the future period
- Comment – would like to think more about this. Saw a 60% ELCC value in another process, so would like to think more about how this relates and the methodology being used here.
    - The more solar you have the less capacity credit you have – inversely related
    - But shouldn't you star at the same place?
    - **FOLLOW UP – send out link to assumptions document.**
- When you consider wind and solar together, doesn't that bolster the ELCC values?
    - Formulas from MISO RIIA are wind and solar curves individually, so this doesn't include that.
    - When you're modeling hybrid projects, will you assume the same ELCC value for solar, regardless of whether it's being paired?
        - Still figuring that out. Need to put some more thought into it.
    - If we reached out to MISO for combined ELCC formulas, would you consider that?
        - Yes, need to talk to MISO staff about how they derived it
        - Jordan Bakke is the RIIA guy at MISO
        - Allen to reach out to MISO and send that info to Eric and John
    - Are we talking about the benefit of solar and storage on the overall system, or ELCC's for hybrid projects specifically?
        - MISO stakeholders are asking for more on this.
    - At some point, MP will have to make a decision about how to model things given the information that's available today.

    - Anna has a slide from IPL on this, from the second stakeholder meeting. Anna will send to MP to take a look at.
- ELCC projections for new and existing wind
    - MISO looks at class average as well as individual wind farms to see how effective they are at delivering energy during peak
        - Not all wind performs the same
    - MP is planning to adjust RIIA ELCC formula based on historical data – any new wind farms will be based on the RIIA formula projection
        - Considered trade secret data, which is why it's not included in the slide (e.g., you don't see the purple and blue lines historical performance).
- ELCC projections for new and existing solar
    - MISO capacity accreditation for solar gives them 50% of capacity in the first year and looks at historical data after that
    - "time zone benefit" is that MISO bases peak on eastern time, and the peak in central time is an hour behind – gives a boost to solar accreditation
    - Can MP share the spreadsheets that were used for these calculations? - Can sign an NDA if needed
        - Eric will circle back on how to approach this from a legal perspective. Typically do NDA's after the resource plan is filed.
        - Part of extension is proposal to submit assumptions by December 1st.
    - Energy Futures group could help with parallel modeling, if MP was ready to share its assumptions.
        - Modeling isn't far enough along yet to share. BUT could share the formulas because that's public information.
        - John willing to jump on the phone and talk it through, without showing the actual numbers.
            - It's not the shape of the line that seems unusual, it's the starting point. Would just need to know how you arrived at the first data point (2020). Suspect it's either about the application of the formula, or the starting point being used. Having that would help to answer the question.
            - Circle back on this – sure there's a way to have this discussion. Guessing it's a difference between HIS and Woods-Mackenzie and vintages of forecasts.
            - **NEXT STEP – MP and Energy Futures Group to connect on this, along with Will Kenworth.**

Modeling existing wing and solar

- MP will have a lot of wind – different between ND and MN
    - Use this for any existing ND wind and any new wind
    - Use MERRA data for windspeeds for same medium months as ND
- Are you seeing major weather pattern changes, and should you be using more recent data?

  - The data set is a bit old
  - Don’t have an answer on how weather patterns change and effect wind
  - Some wind farms have 10 years of data
  - Haven’t seen a consistent trend line in the wind production data – continued to see volatility which generally evens out
    - Can you have wind droughts like you do for hydro – haven’t been able to identify anything
    - May not be able to figure this out for this resource plan, but have been talking about it for future resource plans.
- Approach to modeling solar facilities
  - Needed to do additionally modeling work – worked with SAM tool from NREL
  - Used SolarAnywhere data because they included snow data which is important for modeling in MN and ND

Minnesota Power
2020 Integrated Resource Plan

Modeling Subcommittee Meeting 4
Wednesday, September 30th 2:30pm – 4:30pm

Meeting Objectives:

1. Build a shared understanding of capital and technology curves for wind, solar, and batteries
2. Provide an update on EnCompass
3. Follow-up on questions/comments from previous meeting

Agenda:

**** Please join meeting a few minutes before 2:30pm so we can start on time****

2:30PM	**WELCOME, INTRODUCTIONS, AGENDA REVIEW**
2:35PM	**PRESENTATION AND Q&A: CAPITAL AND TECHNOLOGY CURVES FOR WIND, SOLAR AND BATTERIES**
3:30PM	**ENCOMPASS UPDATE**
3:45PM	**FOLLOW-UP ON QUESTIONS/COMMENTS**
4:30PM	**ADJOURN**

MINNESOTA POWER
2020 INTEGRATED RESOURCE PLAN

Modeling Subgroup Meeting 4
Wednesday, September 30th
2:30pm-4:30pm

Via Zoom

Topics for Discussion

1. Capital and Technology Curves for Wind, Solar, and Batteries
2. EnCompass Onboarding Update
3. Follow-up on Questions/Comments

MP’s Approach to Renewable and Battery Capital Costs

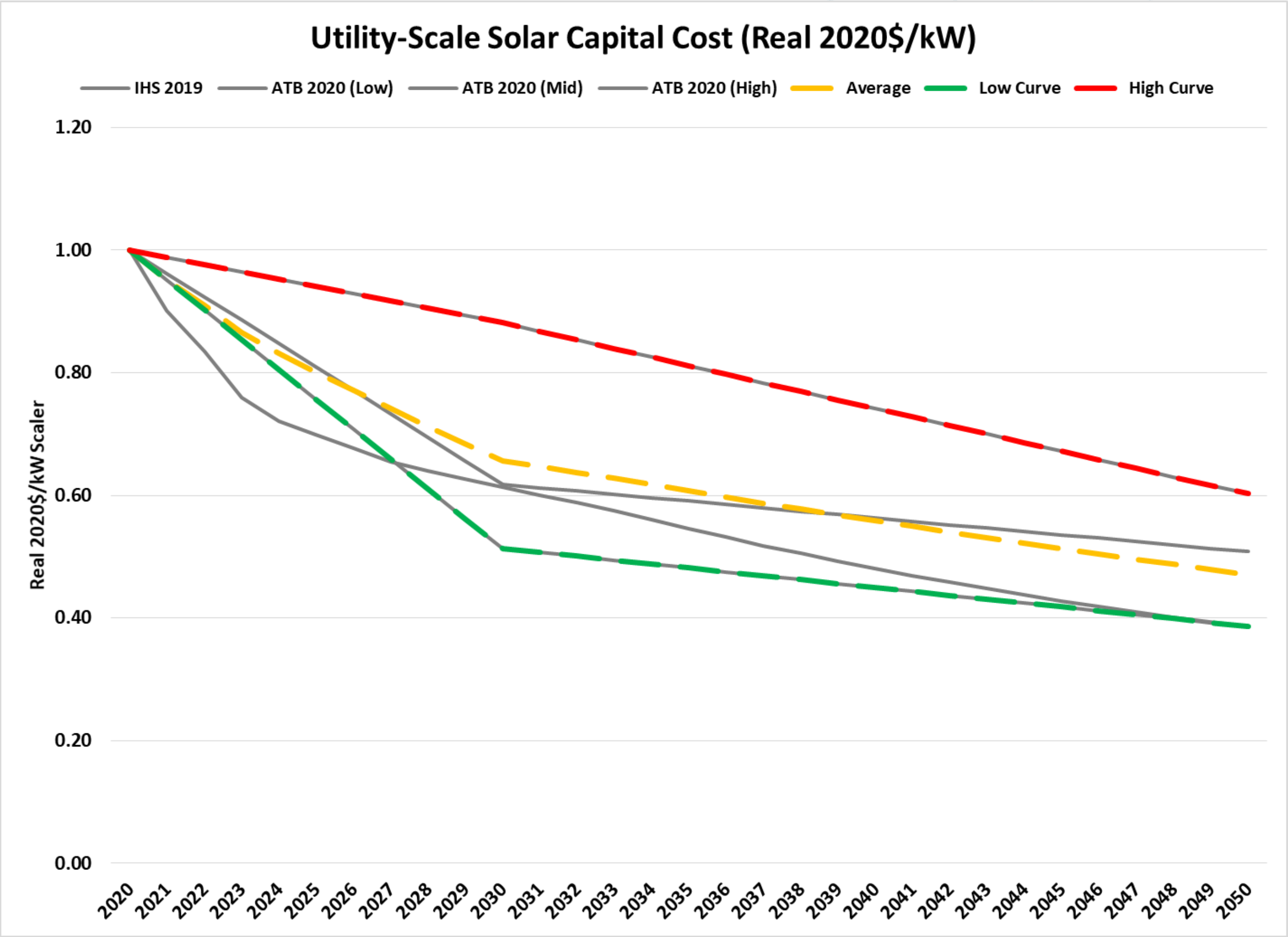
- Upfront Capital:
  - <u>Wind</u> capital assumptions are based on internal expertise & external intelligence. The 2020 capital cost we are using is significantly lower than NREL ATB 2020.
  - <u>Solar</u> capital assumptions are taken directly from NREL ATB 2020.
  - Storage capital assumptions are based on our third-party engineering consultants review. The 2020 capital costs for 4hr Li-Ion storage is in line with NREL considering that MP is modeling 20 year storage assets vs. NREL’s 15 year asset life.

- Transmission Interconnection Costs as discussed previously

- Future installed capital costs are being adjusted utilizing the technology curves presented on the following slides – *We appreciate the feedback and incorporated aspects into the methodology*

Solar Capital Costs Outlook

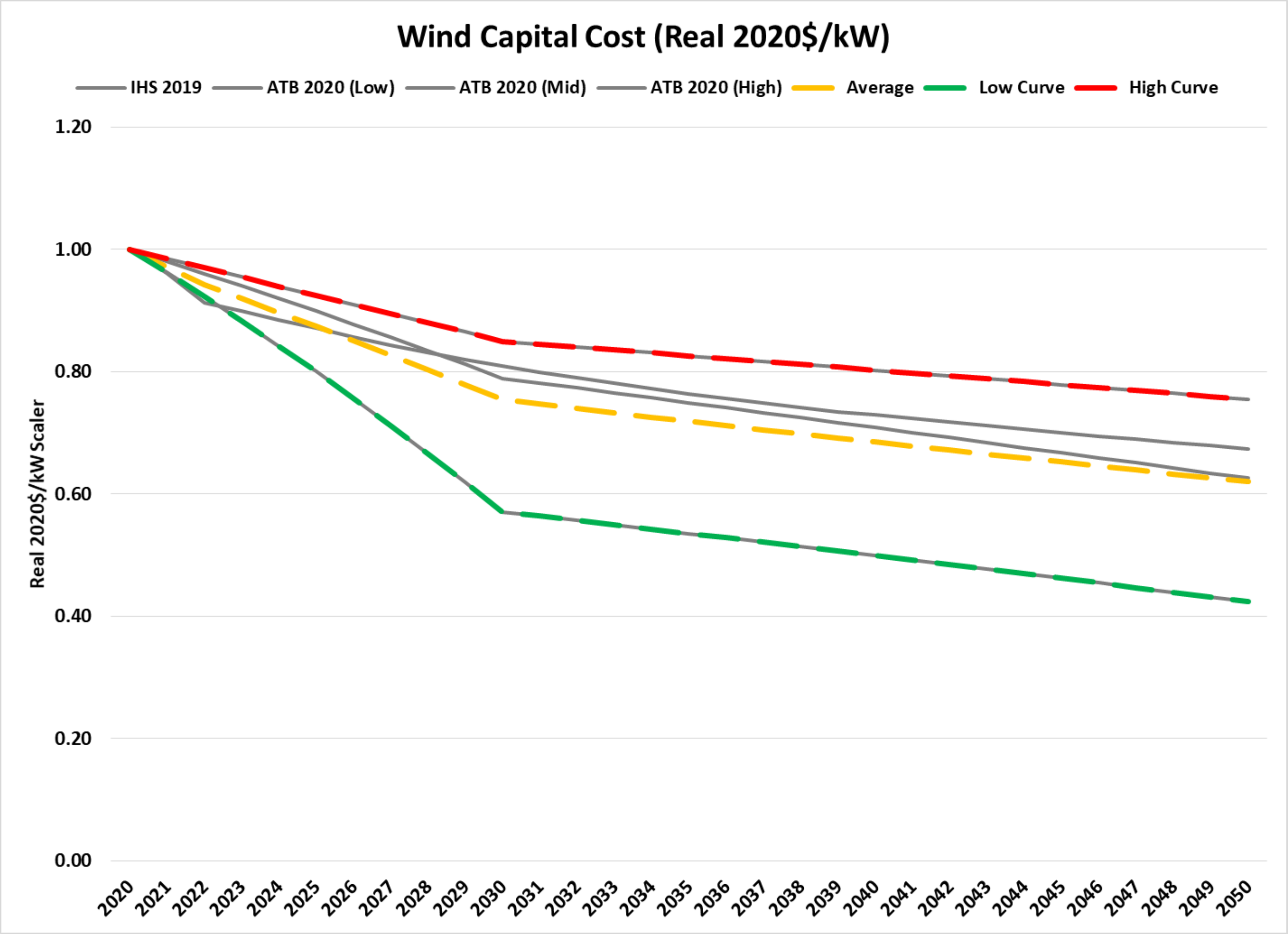
- Utility Scale PV Solar has experienced significant price reduction over the past few years (not reflected on this chart).
- Expectations are for reductions in pricing to continue over the next decade before leveling off into the mid-’30s and beyond.



Wind Capital Costs Outlook

- Wind is seen as a fairly mature technology, however continued improvements still show potential for small reductions in cost over the next decade.

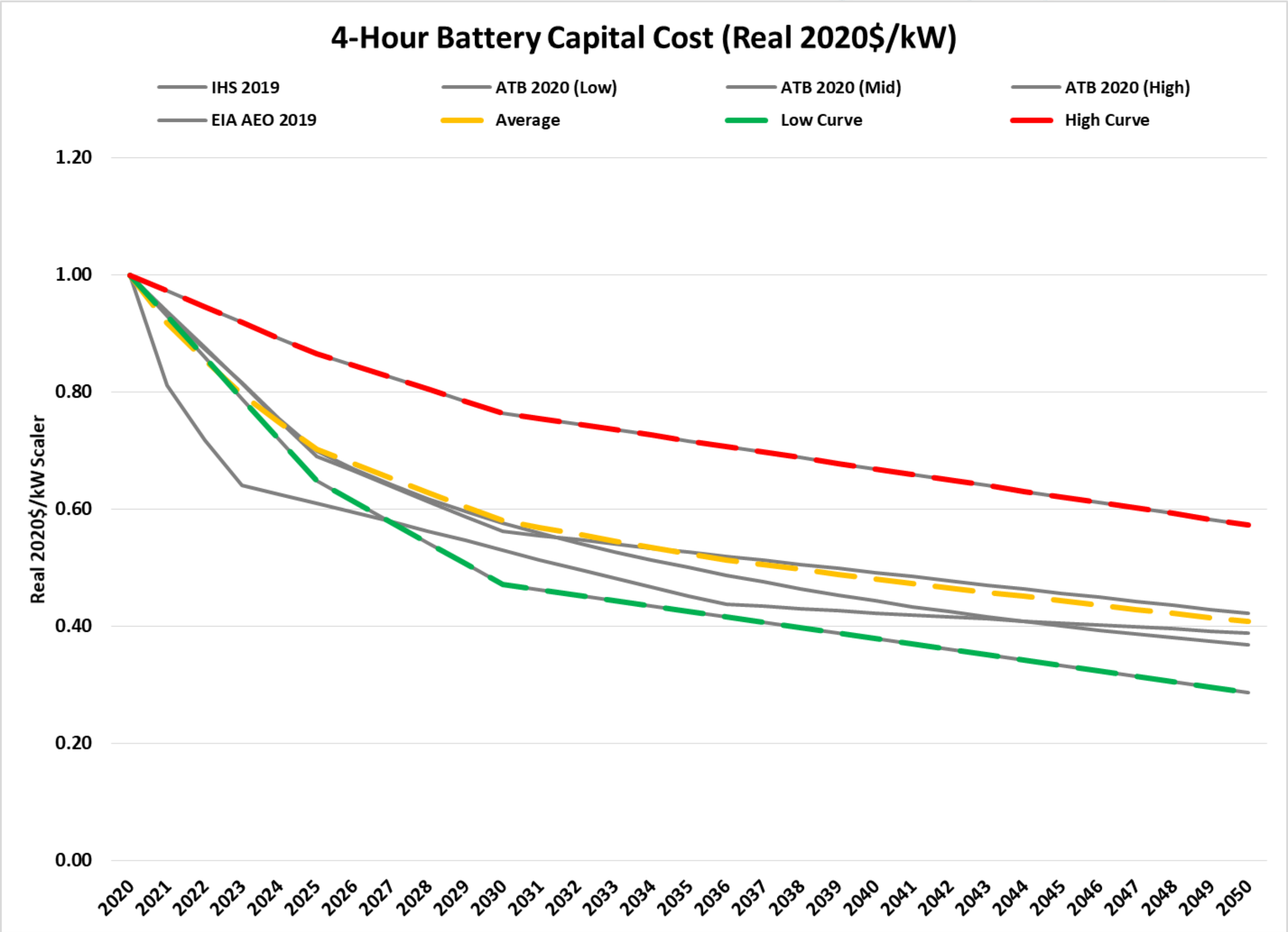
- Wind technologies will continue to see pricing improvements through larger blade diameters, increases in hub heights, and reductions in the number of turbines per project.



Li-ion Battery Capital Costs Outlook

- Li-ion storage is still in its' infancy at a utility scale. Forward technology price curves reflect aggressive pricing improvements over the coming decade and beyond.

- 12hr Flow Battery technologies are being considered with a flat nominal curve to reflect the uncertainty of the technology cycle. (note – not shown in the figure to the left)



EnCompass Modeling Update

Continue to work hard on learning the model while preparing for the IRP analysis

- Moved to the new Encompass model build (Version 4.3) published end of August
- Frequently in contact with Norm resolving issues as they occur and expect that to continue as new technologies and retirement analysis are modeled
  - Many modeling capabilities are untested and will need vetting
- Addressing IT related issues as they arise with the client-server version
- Testing of the capacity expansion module continues while setting up new supply-side and demand-side alternatives
  - Reaching the limits on how large of a problem (i.e. # resource alternatives) it can solve for
- Finished creating front-end and back-end tools for setting up model and to evaluate capacity expansion plan results
- Currently updating the model with IRP assumptions

Response to Questions/Comments Since Last Meeting

- **EV hourly load profiles used in modeling**

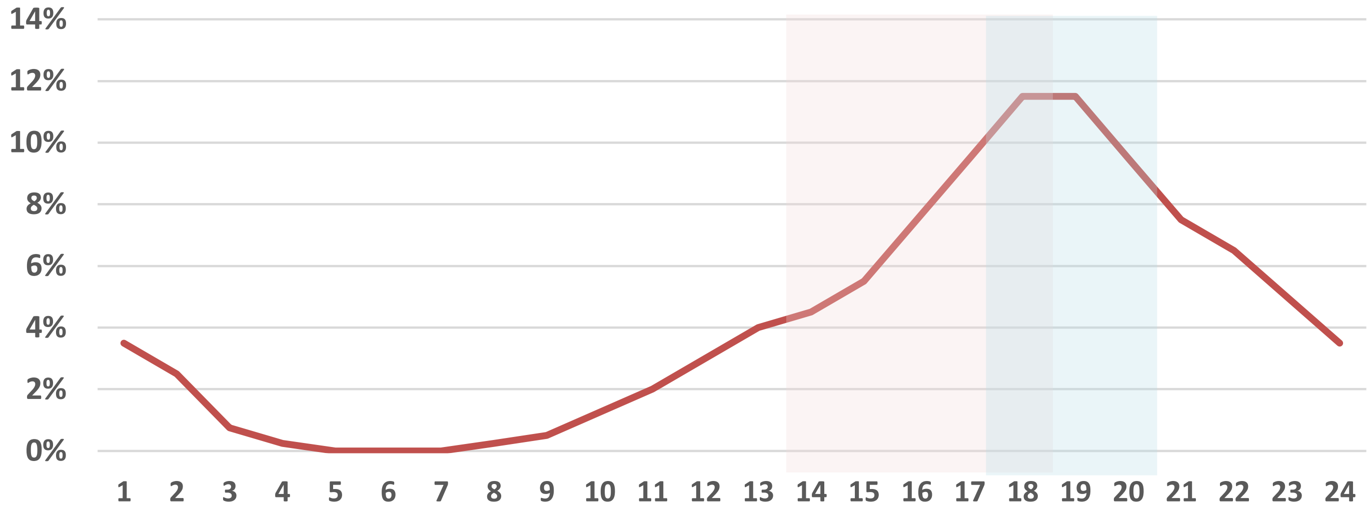
  Response:

  Daily charging patterns are derived from NREL and are used to forecast residential EV demand

  Total EV usage is based on installed fleet size in MP's territory and the average EV kWh requirements

  Charging that overlaps with typical peak hours was used to adjust the MP peak outlook

Share of Daily EV Charging ny Hour
Single Unit Dwelling, Level 1 Charge Pattern



Souce: NREL National Economic Value Assessment of Plug-In Electric Vehicles, 2016

Response to Questions/Comments Since Last Meeting

- **DG solar installation rate per year (i.e. No. of projects/per year)**

- **Does the methodology used for forecasting DG solar growth utilize a "cash flow" model**

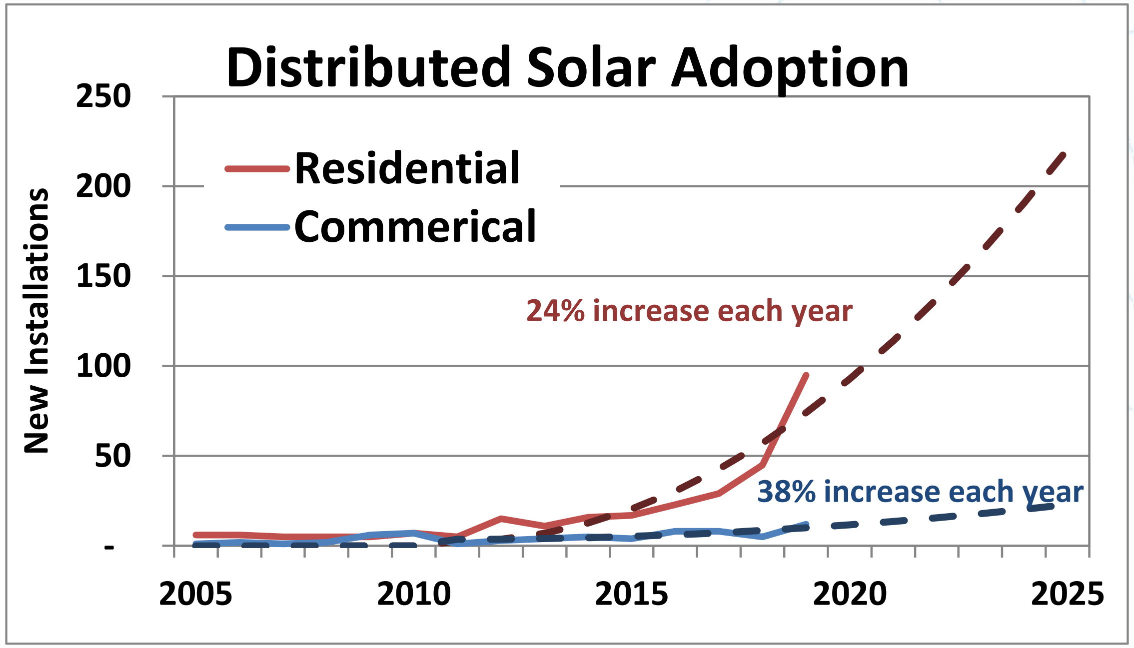
Response:

Currently we have about 3.3 MW of < 40 kW projects installed (roughly 74% of our small scale mandate)

Expecting by 2030:

- *27 MW of new installations*
- *Displace about 27,000 MWh (1.2%) of MP sales to residential and commercial classes*
- *Pace of new installations increase over time*

Modeling residential & commercial is based on historical adoption rates fitted to a technology adoption curve. This modeling does not rely on a cash-flow or propensity model.



Response to Questions/Comments Since Last Meeting

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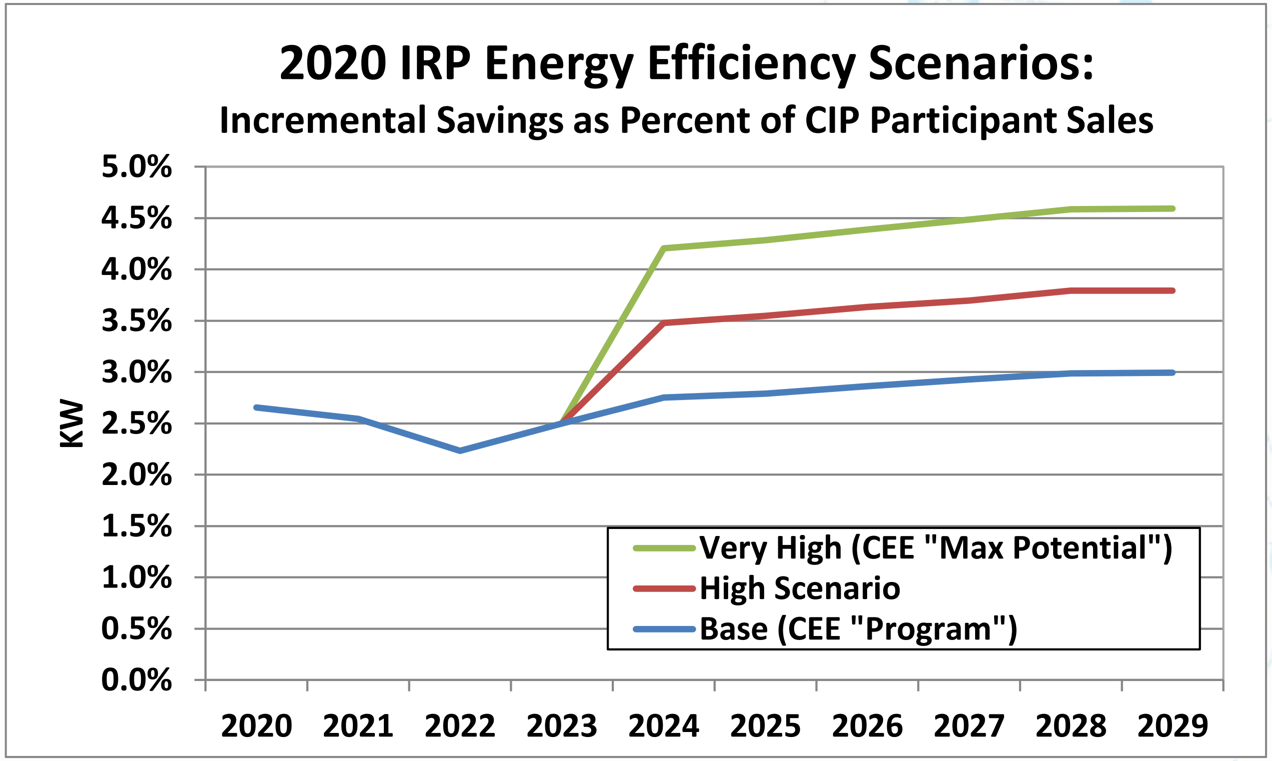
- **Equivalent EE Savings Percentage for IRP EE alternatives**

  Response:

  Minnesota Power developed three EE scenarios for evaluation in the IRP. MP is including the Base (CEE "Program") scenario in the load forecasts. The High and Very High (CEE "Max Potential") scenarios will be included as "supply-side" resource alternatives.

  The three scenarios range from about 2.5% to 4.5% of CIP Participant Sales.



Response to Questions/Comments Since Last Meeting

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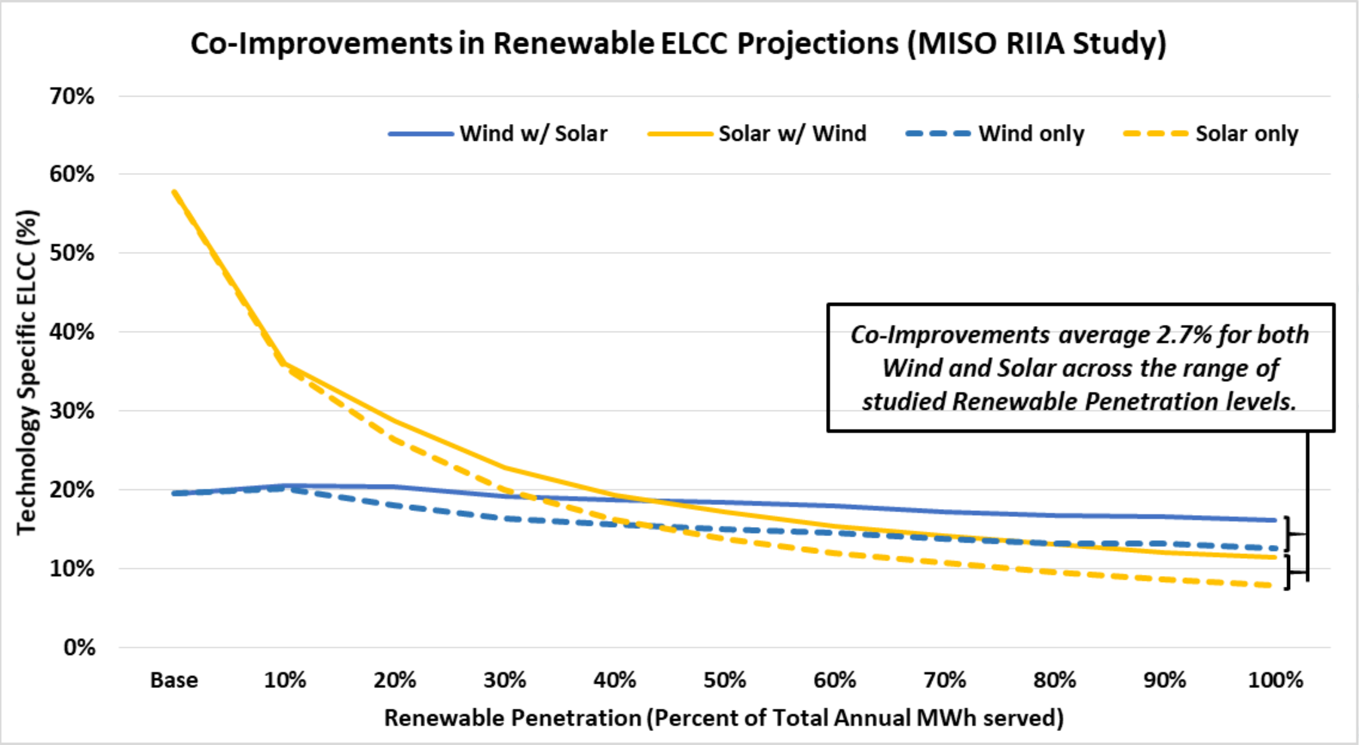
- **What MP learned from MISO on ELCC for Battery and Solar from RIIA**

Response:

MP met with MISO RIIA staff to discuss the co-improvements to ELCC values due to increased penetration levels of both wind and solar technologies.

MISO published the only ELCC formulas for individual resources because the co-improvements are dependent on the ratio of installed capacity.

Based on MISO's study work (and assumptions), the average co-improvement for both wind and solar is about 2.7%.



Response to Questions/Comments Since Last Meeting

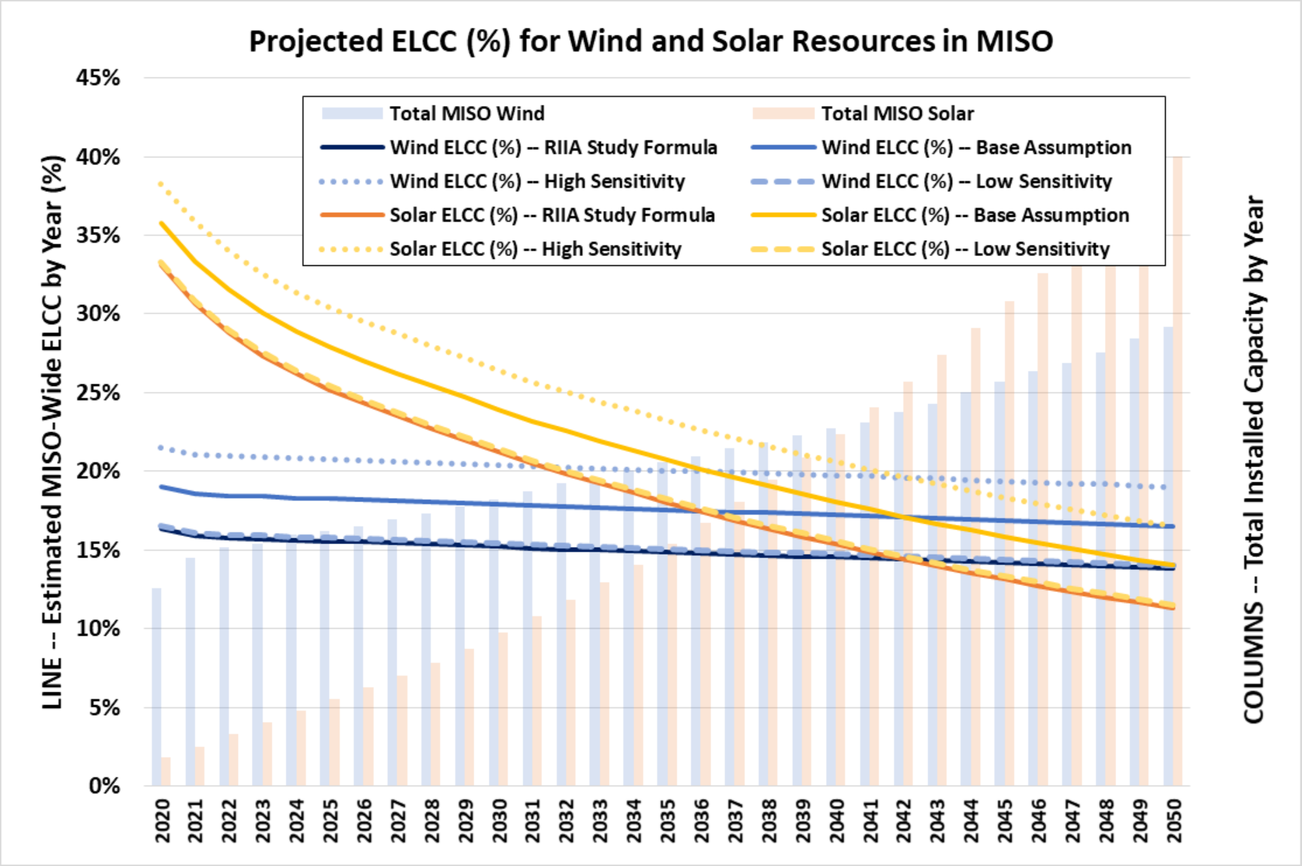
- **What MP learned from MISO on ELCC for Battery and Solar from RIIA**

  Response:

  Projecting future ELCC percentages is dependent on several variables, including the amount and ratio between other intermittent type resources installed.

  We plan to shift the individual wind and solar curves up by 2.7% to account for the co-improvement (base curve).

  We also are planning to have high and low sensitivities which will be ±2.5% from the base curve. These sensitivities are designed to help capture the impacts from other variables, which could include changes in load profiles, intermittent resources, market structures, etc.



Response to Questions/Comments Since Last Meeting

- **How is the "Time of Use" sensitivity modeled in EnCompass**

  Response:

  The Time of Use (TOU) sensitivity is modeled as reducing load during peak hours and increasing load evenly during all other hours to keep the energy sales forecast neutral.

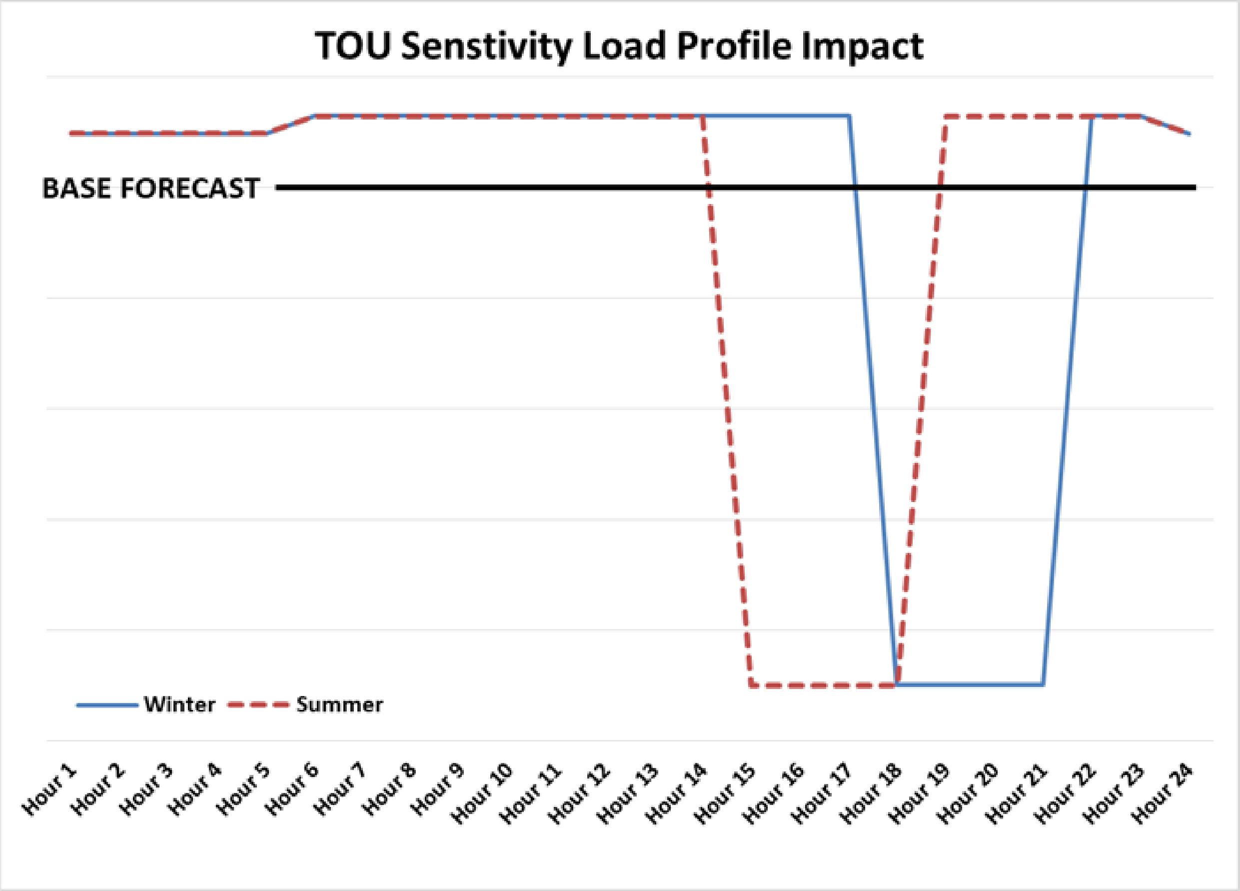
  *The TOU rate is applied to **all** of MP's residential customers*

  Reduction of energy use during peak hours results in a modest reduction in peak demand

  Peak Hours:

  Summer: Hours 15 thru 18

  Winter: Hours 18 thru 21



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Thank you for the insightful discussions and feedback on MP's approach to IRP assumption.

We look forward to continued discussions with stakeholders after the IRP is filed on February 1, 2021

MP IRP Modeling Subcommittee Meeting

September 30th, 2020

Via Zoom

Participants: John Christensen, Eric Palmer, Will Kenworthy, Allen Gleckner, Anna Sommer, Evan Mulholland, Jay Eidsness, Andrew Twite, Laurie Williams, Trevor Drake, Alissa Bemis, Kate Sullivan

**These notes supplement the slide deck*

AGENDA:

- Capital and technology curves for wind, solar, and batteries
- Update on encompass
- Follow up on questions from previous meeting

APPROACH TO RENEWABLES AND BATTERY CAPITAL COSTS

- Assumptions form third party research firm – didn't get wind and solar assumptions this year
- Wind capital assumptions are lower than NRELs ATB 2020 – based on internal expertise
- Solar capital assumptions are taken directly from NREls ATB 2020
    - Used Chicago capacity factor numbers
    - Were the NREL numbers in line with the solar RFP
        - The most recent solar only RFP was in 2017 but those prices are dated and not used here
        - Did another RFP with a muni but they are still contracting and can't provide details but it is very small
- Storage capital cost are coming from third party engineer to keep with consistency (it is in line with NREL's numbers)
- Previously talked about transmission interconnection costs

SOLAR CAPITAL COSTS OUTLOOK

- Graph is in real dollars
- Base case is using the average of the forecasts
- Sensitivity for low and high curve as well
- 1 on the y axis is the 2020 price which comes from NREL ATB for solar
- Thought the NREL forecast was reasonable for the region
- What is the lifetime assumption for solar assets?
    - Roughly 30 years – most people, including developers are comfortable with this
- Assuming capacity factor in the low 20s (lower than NREL ATB)

WIND CAPITAL COSTS OUTLOOK

- Third party forecast and ATB providing 4 curves
- Avg curve that will be used in base case is slightly lower than highest 3
- Some improvements in the next 20 years

LI-ION BATTERY CAPITAL COSTS OUTLOOK

- EIA curve is added to the four other curves
- 45% reduction between now and early '30s because it is a newer technology
- Not using these technology curves to model flow batteries – to counteract that in the IRP they are looking at it as a flat nominal curve (holding it constant)
- What sizes are the generics?
    - 100mW
- Is there a cycling restriction in the generics?
    - Would need to review – haven't gone into it much
- Do you have a generic hybrid (solar + storage)
    - Hoping to model a DC coupled and hopefully including that otherwise the model can select a solar and storage assets at the same time
    - Xcel is looking into this and Allen Gleckner offered to provide some insight
- Why not use the lowest curve?
    - MP took the net present value in real dollars across the entire time series

ENCOMPASS MODELING UPDATE

- Continuing to prepare the model
    - Running version 4.3
    - Continually in contact with Norm and modeling new technologies, such as DR
    - Got a stable build about three weeks ago
    - Working to lower the run times – currently 300 minutes per case (have about 500 cases)
    - Finished created front-end and back-end tools
    - Currently working on updating the model with IRP assumptions – hoping to have it done in the next few weeks
- Xcel is having high numbers of renewables in their modeling – related to dispatch
    - Not sure if this is related to inputs or the models
    - Let Ana know if MP also runs into this issue
    - Do carbon regulations affect this?
        - Happens later on the planning period but don't think that is affecting it
    - Any issues with Tax breaks?
        - Not that Ana has seen
        - Issues with curtailment values seeming odd because the modeling was selecting the curtail existing assets that were rolling off of the PTC – makes sense but made for weird curtailment patterns

RESPONSE TO QUESTIONS FROM PREVIOUS MEETINGS

- EV hourly load profiles used in modeling

    - Basing daily charging patterns from NREL and applying that to EV usage and growing over time
    - This will capture impact on summer and winter peak
    - EV growth expectations are offset by DG solar growth
    - Doesn't make a huge impact on peaks
- DG solar installation rate per year and methodology for DG solar forecasting
    - New installations per year shown in graph (through 2025)
        - Residential is based on historical adoption rate with technology adoption curve – about 24% growth
        - Commercial is 38% growth
- Equivalent EE saving percentage for IRP EE alternatives
    - Base case is abut 2.5% which increases over time (based on CEE study)
    - High scenario is midpoint between base case and very high case
    - The 2021 – 2023 time period comes from what MP submitted in the triannual
    - Are the costs for each scenarios connected to the CEE study?
        - Yes, MP worked with CEE to better represent the cost for their customers
    - How are these costs going to be represented?
        - Showing them as incremental costs over the years they would be incurred – don't know how EnCompass will show them
        - Base costs are not in the model – high and very high scenarios will be included as "supply side" resource alternatives
        - EnCompass can't levelize costs for you - need to do it on the front end
            - Recommend doing this
    - How do you represent when the money is spent?
        - Same problem as supply side resources
        - Because you have to end your IRP at some point you are truncating something – which is why it is good to levelize the costs
        - Are you assuming utility discount rate? – depends on policy that applies
    - How did Xcel handle the cost side? Did they levelize the cost?
        - Not sure – CEE might know
        - Might be trade secret
        - MP will give more thought to this
- What MP learned from MISO on ELCC for battery and solar form RIIA
    - Worked with MISO staff to understand RIIA analysis
    - MISO provided data from their analysis
    - Overall, good approach – appreciate that MP is taking co-benefit into account
    - Storage would likely change these curves (increase solar and wind)
    - How is this going to change between winter and summer?
        - It is not, don't have seasonal construct (don't show how things are accredited during winter and summer)
- How is the TOU sensitivity modeled?
    - Modeled as reducing load during peak hours and increasing load evenly during all other hours to keep the energy sales forecast neutral
    - Assuming the TOU rate is applied to all MP residential customers

    - Around a 20mW load reduction during winter
    - Is there an industrial TOU stakeholder group?
        - There might have been discussions but not sure if it was an order point from the PUC
        - There is an ongoing stakeholder process, and what they are looking at is a default TOU rate with a low income carveout which is consistent with what is being modeled
- Is NTEC assumed as a resource in all runs?
    - Yes, deal with court decisions as it happens
    - Estimating it will be about 6 months before we hear from the courts
- Will we have another meeting to go review draft results?
    - Not likely – focus is on getting the filing done by Feb 1st.
    - Think they will deliver the framework for the IRP database around the same time