I. MINIMUM SYSTEM NEEDS

Our resource planning process focuses on achieving deep carbon reductions while serving our Upper Midwest customers reliably and affordably. The Minimum System Needs chapter of our July 2019 Resource Plan described how we arrived at the minimum amount of resources our system will need through the planning period to serve our customers.

Our approach to identifying the NSP System's minimum system needs is largely unchanged from our initial filing; however, we have updated certain inputs. In this section, we provide an overview of these changes and provide an updated net resource surplus/deficit view, as well as a summary of Reference Case results. Together these results form the basis of our Supplement Preferred Plan modeling and selection.

Key updates to our minimum system needs assumptions include:

- Corporate load and energy demand forecasts are updated to fall 2019 vintage;
- MISO Resource Adequacy (RA) and planning reserve margins are updated to 2019 guidance, including forward-looking guidance from MISO's Transmission Expansion Planning (MTEP) process;
- Removed the Reliability Requirement as an *ex ante* input, instead allowing modeling software to select resources that ensure reliability, according to identified system needs; and
- Baseline resources now include only existing and authorized additions of resources as of January 2020.

We describe our approach and inputs used to identify minimum system needs further below.

A. Determining Customer Needs

Forecasting customers' needs for electricity is a key component of any resource plan and provides the foundation for determining the type and amount of resources that will be needed over the 15-year planning period. We start with an internally developed customer needs forecast, which is derived from customer demand and energy forecasts and adjustments for the effects of energy efficiency resources (EE), distributed energy resources (DER), and electric vehicle (EV) adoption. To this, we add a reserve margin that is prescribed by MISO. We then subtract the energy resources we already have, or expect to have, on our system, in order to determine our net surplus or need.

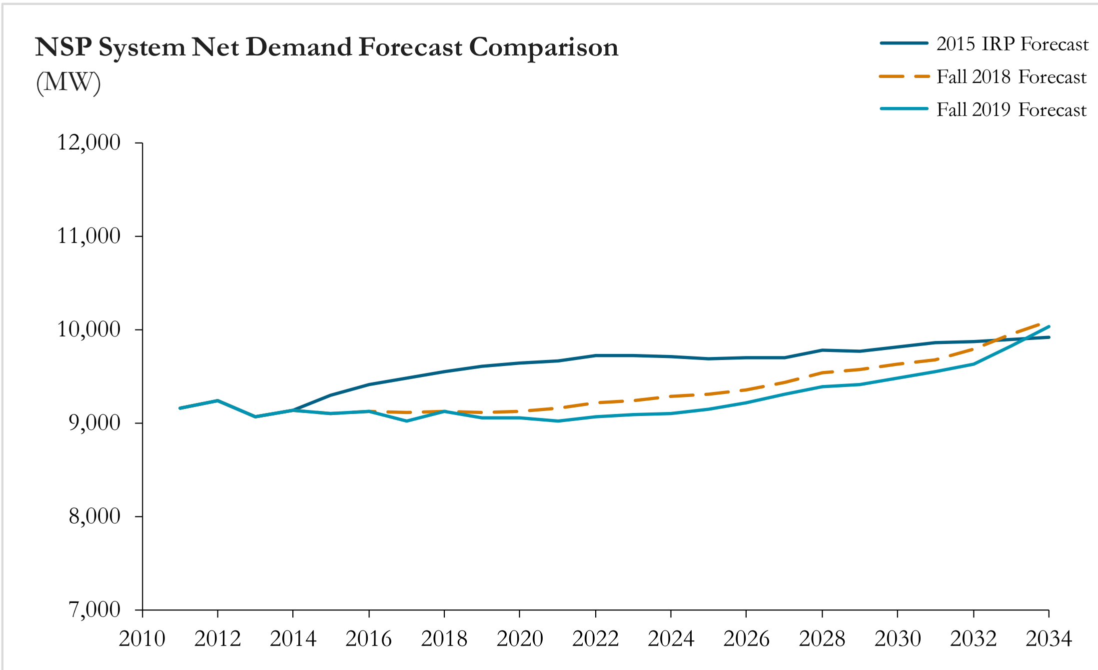
Forecasting our customers' energy needs starts with a peak-hour demand forecast (in MW) and a forecast of our customers' total energy needs (in MWh) for each year of the planning period. We updated the customer needs forecast for this Supplement as discussed below.

1. *Corporate Forecast for Peak Demand Requirements*

Our Load Forecasting team uses econometric analysis and historical actual coincident net peak demand data to determine forecasted system demand, which forms the basis of our capacity requirements for each planning year. From these corporate forecasts, we make adjustments that add back in the effect of anticipated future EE achievements and distributed solar generation, so that we can model EE and distributed solar as competing with supply-side resources in the modeling process. This was a change we first implemented with our July 2019 initial Resource Plan filing and is further discussed below.

The peak corporate demand forecast for this Supplement shows relatively slow load growth, with an average annual growth rate of 0.7 percent, after accounting for reductions to demand from future EE achievements. Figure I-1 below shows the updated corporate net load forecast – called "Fall 2019 Forecast" in the Figure – in relation to the forecast from our initial Resource Plan (Fall 2018 Forecast) and our previous Resource Plan. In general, we expect load to be slightly lower than the forecast used in our initial filing, due to several factors. Some factors reducing the demand outlook include weather-driven near-term energy demand declines, additional anticipated EE savings, and the removal of certain anticipated commercial and industrial load where customers' plans had changed since our fall 2018 forecast. In the out years of the forecast, however, we anticipate more rapid growth as a result of EV adoption. We provide additional discussion addressing these changes in Attachment A, Section II: Load Forecast and III: DER Forecasts.

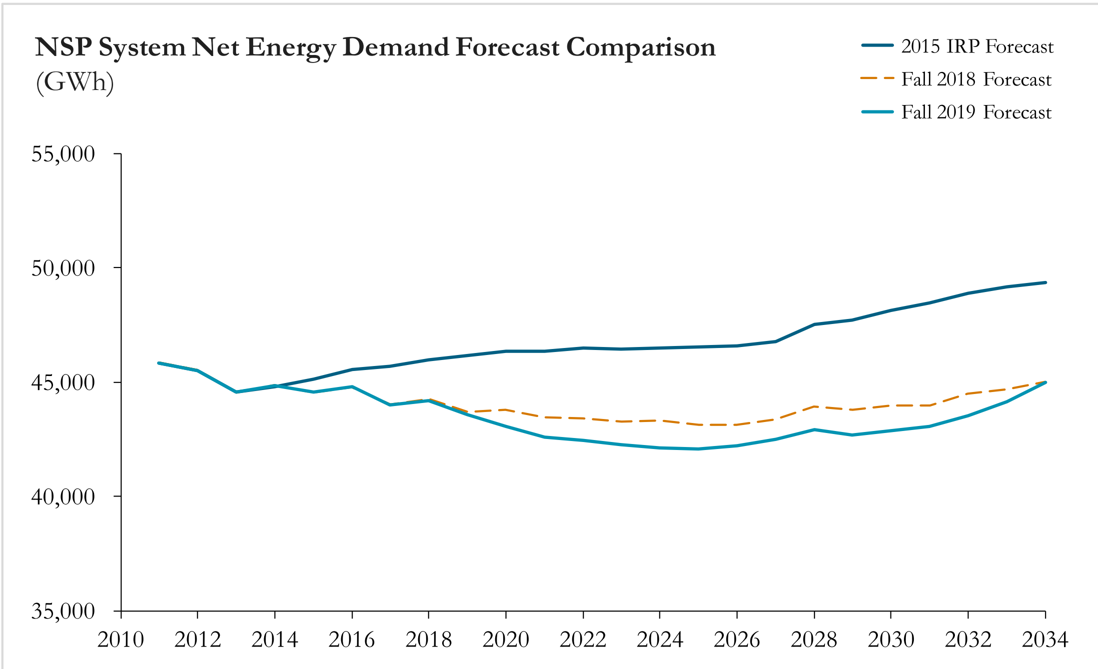
Figure I-1: Corporate Forecast of Peak Load by Vintage



2. *Corporate Forecast for Energy Requirements*

In addition to forecasting peak demand, we also forecast our customers' energy requirements. The energy forecast underlying this Supplement indicates that we expect net energy requirements to be relatively flat, with approximately 0.2 percent growth over the full 2020-2034 planning period. Figure I-2 below portrays our net energy demand for this Supplement, as compared to the forecast in our initial filing and our previous Resource Plan. As discussed above, changes from our Fall 2018 to Fall 2019 forecast vintages are attributable to changes in customer consumption and future plans, additional savings from energy efficiency measures and anticipated EV adoption.

Figure I-2: Corporate Forecasted Net Energy Requirements by Vintage



3. *Forecast Adjustments for Anticipated Customer Trends*

After determining the base peak capacity and energy demand forecasts, we make adjustments to account for the impact of events or trends we reasonably expect to occur in the planning period. The adjustment types and methods have not changed since our initial filing, although we have updated the forecasts for DER and EVs. We also made certain adjustments to overall demand for large customer changes expected in future years. We note that the baseline forecasts used in this Supplement do not reflect potential effects of the COVID-19 pandemic and resulting recession on our energy demand. It is too early to know to what extent energy demand will decline in response or the duration of these effects.

4. *Adjustments to Model Certain Load-Modifying Resources as Competing with Supply-Side Resource Options*

As noted in our initial filing, this is the first resource planning cycle in which we have treated load-modifying resources – such as energy efficiency, demand response, and distributed generation – as competing with supply-side resources in our modeling process. Previously, we netted out these resources at an assumed level of adoption across the planning period, and our corporate forecasting process continues to use this method to estimate our net energy and load into the future. However, in the initial plan we filed in July 2019, we tested the economic impact of including various "bundles" of EE and DR – in other words, portfolios of EE or DR measures at an assumed average cost – in order to allow these resources to compete with traditional supply-side resources such as large-scale renewables or gas resources. In order to avoid double counting, however, this requires us to adjust our corporate forecast for use in Strategist and EnCompass modeling.

Figure I-3, below, illustrates the adjustment process. We removed the assumed effect of existing and planned demand-side management programs and distributed solar from the corporate forecast, so that we could model the economic effect of the first two EE Bundles separately. In our initial filing we showed that these two EE Bundles were economic relative to a scenario in which no incremental EE measures were pursued, thus for the purposes of this Supplement, we have included them in our baseline modeling. The end result is a net demand and energy forecast for use in the Resource Plan.

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Figure I-3: Illustrative Adjustments to Translate Corporate Forecasts to Resource Plan Model Inputs

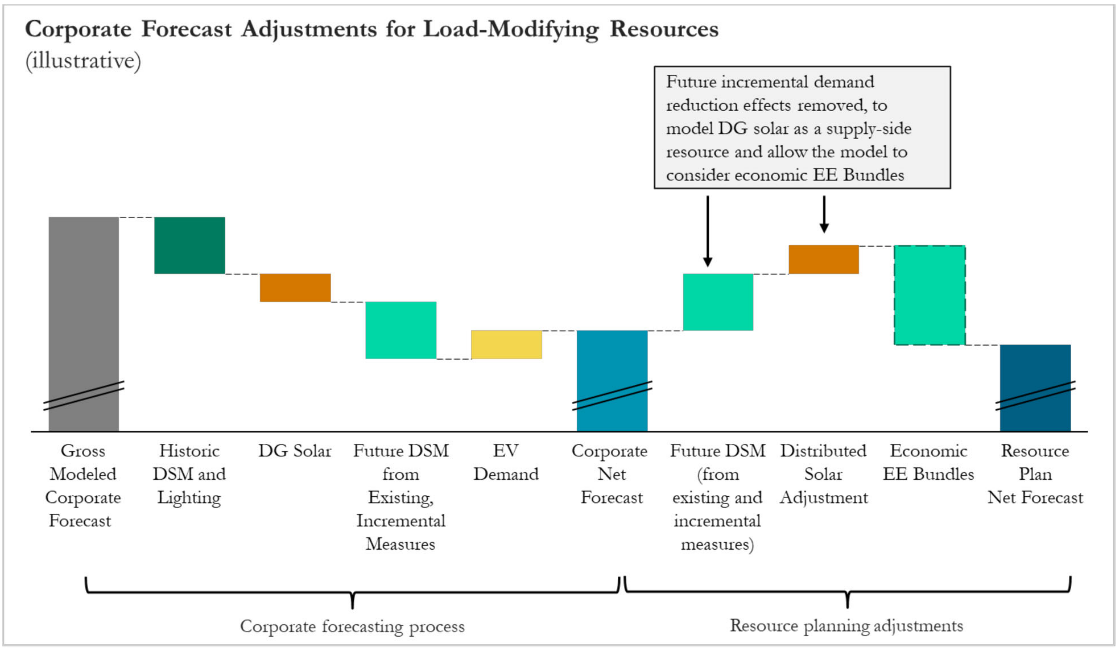


Figure I-4: Net Peak Demand Forecast Adjustments for Resource Plan Modeling[1]

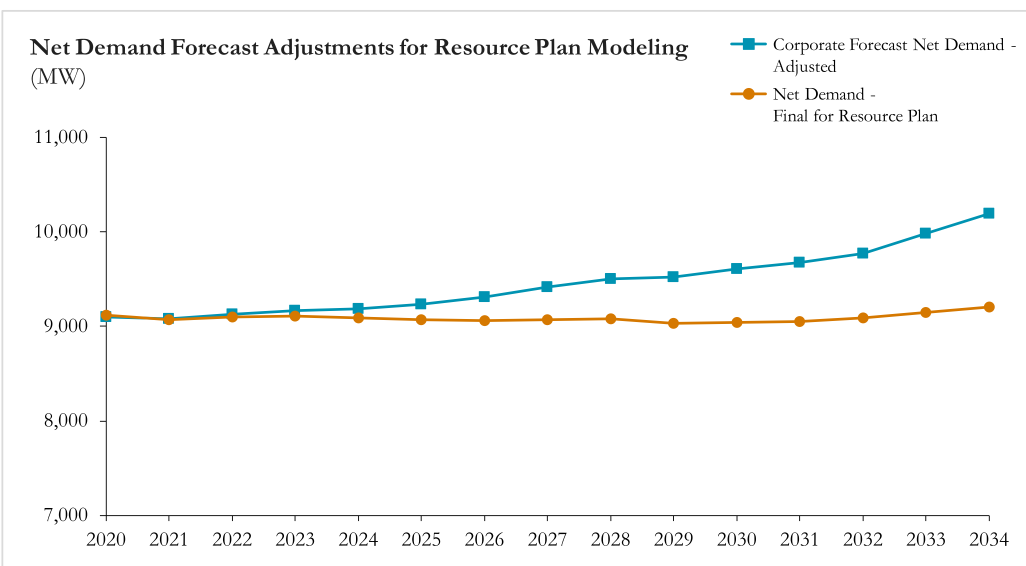
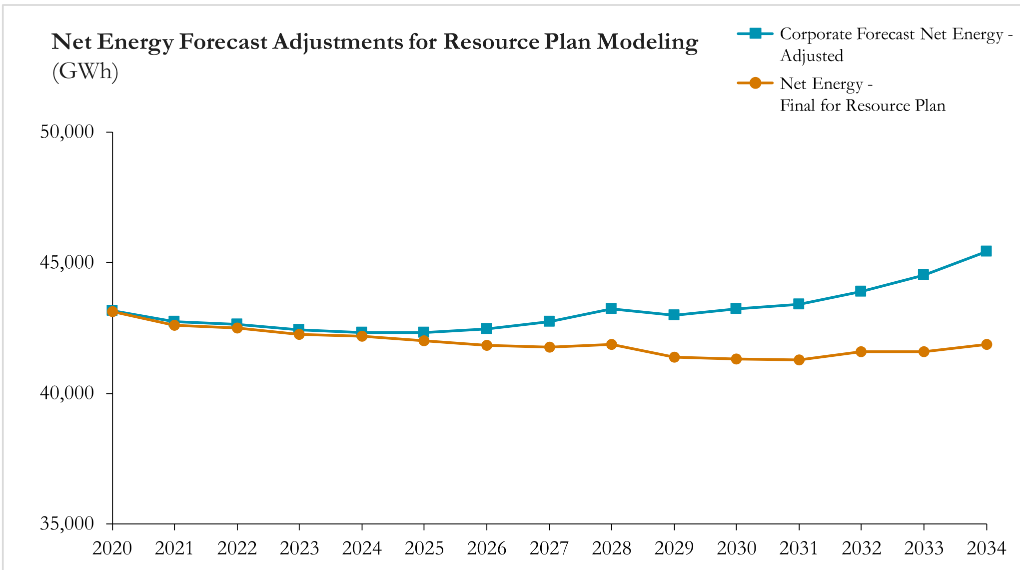


Figure I-5: Net Energy Requirements Forecast Adjustments for Resource Plan Modeling[2]



5. Customer Green Energy Programs

Finally, while they have no effect on total system energy or peak demand requirements, we note the Company offers customer programs that allow customers to specify a preference for renewable energy, and we then correlate that demand to specific resources. Windsource and Renewable*Connect are two programs where we procure renewable energy on behalf of subscribed customers and they pay for these resources directly through Program-specific rates.

In 2003, the Company initiated Windsource, which is a green tariff program that allows customers to subscribe to blocks of wind energy for a premium price. The Company began offering Renewable*Connect (R*C) as a pilot in 2017, in an effort to meet customer demand for a voluntary green tariff that also includes solar resources. In January 2019, we proposed to expand the pilot to a full program and roll

[1] Corporate Forecast Net Demand - Adjusted represents the corporate forecast further adjusted to model distributed solar as a supply-side resource.
[2] Corporate Forecast Net Energy Adjusted represents the base corporate forecast further adjusted to model distributed solar as a supply-side resource.

Windsource customers and resources into the R*C program. The Commission approved our proposal in August 2019.[3]

Customer interest in these programs has been strong, and there are over 2,350 customers on the R*C waiting list.[4] We anticipate a full rollout of the next tranche of R*C to begin in 2022 when our proposed R*C resources come online, and that this tranche will be fully subscribed given the existing customer interest; however, we are not able to confirm this until pricing for the month-to-month and long-term-offer options are finalized and customers sign contracts. We discuss approved and proposed resources aligned to serve Windsource and R*C customers below in Section C. Baseline Resources.

B. Resource Adequacy Requirements

MISO prescribes Resource Adequacy (RA) requirements that are intended to help ensure adequate reliability of the bulk electric supply system. MISO's RA process requires load serving entities (LSEs) like the Company to maintain resources that exceed their level of demand by a specific margin – the planning reserve margin or PRM – to cover potential uncertainty in the availability of resources or level of demand.[5] These RA requirements are fundamental to the resource planning process, informing the level of capacity we need in our portfolio to adequately serve customers' summer peak demand. MISO also continues to explore ways in which it can ensure RA requirements adequately reflect system needs across all hours of the year – through its *Resource Availability and Need* (RAN) and *Renewable Integration Impact Assessment* (RIIA) work – and includes forward-looking capacity accreditation assumptions in its own transmission planning process. Similarly, in an environment with increasing variable resources, the Company must examine resource adequacy in a more nuanced way than it has in the past, to ensure we have the right resource attributes on our system to meet customer needs in every hour of every day.

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[3] *See* Docket No. E002/M-19-33. IN THE MATTER OF NORTHERN STATES POWER COMPANY'S D/B/A/ XCEL ENERGY, PETITION TO EXPAND ITS RENEWABLE*CONNECT PROGRAM, *Order Approving Petition with Modifications* (August 12, 2019).
[4] Data as of December 2019. *See* Docket No. E002/M-20-380. ANNUAL COMPLIANCE FILING, TRACKER ACCOUNT REPORT, AND PROPOSED 2021 TARIFF RATES. (March 30, 2020) at 1.
[5] The factors affecting availability and demand include: Planned maintenance, Unplanned or forced outages of generating facilities, Deratings in resource capabilities, Variations in weather, and Load forecasting uncertainty.

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EnCompass modeling – which evaluates our system's dispatch capabilities on an hourly chronological basis – allows us to conduct a deeper examination in this Supplement, examining the potential for energy and capacity shortfalls on an hourly basis. We discuss our analysis capabilities relative to resource attributes on our system further below and in Attachment A, Section VI: Resource Attributes.

1. *MISO Reserve Margin Requirements Applied to the NSP System*

MISO currently bases its PRM requirements on an annual analysis of the reserve required to avoid loss of load events. Based on the needs indicated in MISO's 2020-2021 Loss of Load Expectation Study (LOLE Study) the Company calculated its effective reserve margin for this Supplement to be 3.46 percent, in comparison to the 2.98 percent applied in our initial filing. This result increases the amount of minimum "buffer" capacity the Company must maintain on the NSP System. We further discuss how we derived this reserve margin below.

For 2020, MISO has indicated an unforced capacity (UCAP) PRM of 8.9 percent,[6] and this requirement remains relatively constant at 8.8-8.9 percent over the full MISO planning period to 2029. We determine the NSP-specific reserve margin based on this information, and the coincident peak demand factor of our own peak load in relation to the MISO peak. Consistent with our initial filing, we continue to estimate a coincident peak demand factor of 95 percent; meaning that we expect to experience load levels that are approximately 95 percent of our peak load during times when the total MISO system load is peaking. Considering the MISO PRM and our own coincident peak factor together, our NSP-system effective reserve margin drops from the 8.9 percent MISO-wide PRM to 3.46 percent.

Figure I-6: MISO Planning Reserve Margin Calculation – NSP System Planning Year June 1, 2020 to May 31, 2021

$$(95\,percent\ coincidence\ factor) x\ (1 + 8.9\,percent) - 1 \\ = 3.46\,percent\ effective\ reserve\ margin\ for\ NSP$$

[6] UCAP refers to units' Unforced Capacity Rating, which is a function of the unit's installed capacity (ICAP) and its anticipated forced outage rate. A generator's anticipated forced outage rate is typically based on the individual unit's historical performance. UCAP = ICAP x (1 – Forced Outage Rate). *See* "Planning Year 2020-2021 Loss of Load Expectation Study Report" at 21. The Study also provides the value in ICAP, which refers to units' Installed Capacity Rating, which is a capacity accreditation measure based on annual or historical tested generating. The ICAP is the lesser of the generator verification testing capacity or the interconnection service capacity.

Applying our effective reserve margin to our annual load forecasts over the planning period determines our overall capacity obligation. We illustrate this calculation for 2020 below.

Table I-1: Capacity Obligation Calculation – 2020 Example

Total Capacity Obligation Component	**Value**
Forecasted load	9,115 GW
NSP Effective Reserve Margin	x (1+ 3.46%)
NSP Obligation	**= 9,430 GW**

Our updated estimated obligation for all planning period years can be found in the updated Net Resources and Capacity Surplus/Deficit table in Section I.D below.

2. *NSP Resources Capacity Accreditation*

After we determine this MISO obligation level, we consider the types of resources suitable to meet the requirement. MISO's tariff and business practices set forth procedures to enable various types of resources to be used to achieve our RA requirements: (1) capacity resources,[7] (2) load modifying resources,[8] and (3) energy efficiency resources.[9]

Resource accreditation represents a measure of a resource's reliable contribution to System RA needs. A generator's operation, maintenance, and utilization directly impact the portion of nameplate capacity rating currently recognized as an accredited resource. Therefore, for a resource's expected contribution to RA, we use UCAP values instead of ICAP. UCAP is calculated differently for dispatchable resources (e.g., nuclear, natural gas, coal), EE, and DR as compared to non-dispatchable, variable resources (e.g., wind and solar). We discuss how these values are determined in our initial filing.[10]

The RA values for most types of resources have not changed between our initial filing and this Supplement. However, for variable resources – especially wind – MISO

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[7] Physical Generation Resources (i.e. physical assets and purchase agreements), External Resources if located outside of MISO's footprint, and DR Resources participating in MISO's energy and operating reserves market, available during emergencies.
[8] Behind-the-Meter Generation and DR available during emergencies, which reduces the demand for energy supplies coming from the LSE.
[9] *Energy Efficiency Resources*: Installed measures on retail customer facilities designed and tested to achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service.
[10] *See* 2020-2034 Upper Midwest Integrated Resource Plan at Page 53.

modifies its assigned RA values from time to time. In its latest report, MISO assigned wind an Effective Load Carrying Capability (ELCC) of 16.7 percent for wind in Zone 1,[11] which is higher than the 15.6 percent we used in our initial filing. This means that for every 100 MW of installed wind capacity, we can count 16.7 MW toward our RA requirements. MISO has not issued guidance regarding forward-looking wind ELCC values, so we use 16.7 percent across the planning period.

We have also updated our approach to accounting for solar RA values, in response to MISO's recent findings in its *Renewable Integration Impact Assessment* work. This study found that, as solar capacity on the MISO grid increases, it is expected to contribute a diminishing marginal amount of capacity value. This is consistent with other utilities within MISO and other jurisdictions approach modeling solar resource adequacy values.[12] In response, MISO's latest Transmission Expansion Plan analysis uses solar capacity accreditation values that start at the current 50 percent level in 2020-2023 and decline to 30 percent by 2033. We have elected to mirror this assumption in our Supplement modeling, although we have also conducted a sensitivity that holds solar ELCC constant at 50 percent throughout the planning period.

3. *Resource Attributes and the Reliability Requirement*

In our initial Plan, we discussed the need for a Reliability Requirement, that would maintain sufficient firm dispatchable capacity on our system over the long term, in order to meet customers' energy needs in every hour of every day. This Requirement was derived based on real-world operating conditions: we have, in fact, already encountered days when wind and solar are not available and, but for dispatchable generation on our system, customers' expectations of reliability would not have been met. These were detailed in Appendix J2 of our initial filing. Given the amount of dispatchable capacity that is scheduled to retire from our system in the next 15 years, the volume of new variable, renewable resources we propose to add, and the fact that MISO planning constructs do not yet incorporate the potential effects of vast variable resource additions, we derived a Reliability Requirement as a starting point to ensure that our system is resilient and that our customers experience the system reliability they expect.

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[11] *See Planning Year 2020-2021 Wind & Solar Capacity Credit*. MISO (December 2019), at 4. Available at: https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf

[12] For example, DTE Energy, Indianapolis Power & Light and Dominion Virginia – among others – use declining solar ELCC in their resource plan modeling. Further, the California Public Utilities Commission uses an assumption of declining marginal ELCC, both their resource planning and resource adequacy proceedings. Please see Attachment A, Section VI: Resource Attributes for further discussion.

That said, we recognize that, in our initial filing, we were not able to complete robust hourly modeling to analyze more precisely the amount of capacity needed to avoid such periods of unserved energy. This was, in part, because Strategist is not an hourly dispatch model; rather, it provides a view of needed capacity expansion to meet annual requirements according to load duration curve assessments. In order to more fully examine the potential need for firm and dispatchable resources to meet intra- or inter-day net load, we are examining unserved energy potential through our hourly chronological dispatch modeling. In other words, we have not included an *ex ante* Reliability Requirement in our baseload studies. Instead, we have modeled an unconstrained system in Strategist and EnCompass capacity expansion functionality, and then we used EnCompass 8,760-hour chronological modeling to determine our Preferred Plan's reliability risk exposure under low renewable availability conditions. We discuss our findings resulting from EnCompass modeling in Section II. Modeling Framework and Results and Attachment A, Section XI: Supplement Preferred Plan Sensitivities – Reliability Analyses provide additional discussion on how we approach resource attributes in planning in Attachment A, Section VI: Resource Attributes.

C. Baseline Resources

After evaluating customer needs and MISO RA requirements, we then evaluate the baseline of resources we already have to serve customers. This includes all owned, contracted, or otherwise available resources on the system or that have received regulatory approval as of January 31, 2020, through their established expiration dates.[13] We note that this is a departure from our approach in our initial filing, where resources we had proposed and were pending approval were also included. This results in a baseline maximum capacity of over 15,000 MW,[14] approximated below by resource type:

- 4,200 MW of wind, including over 1,500 MW of capacity currently under development
- 1,000 MW of solar (including community and grid-scale solar)
- 950 MW of other renewables (including biomass, landfill gas, and hydroelectric resources)

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[13] This could include refer to contract expiration, planned retirement or financial end of life. Black start resources are one exception to this general rule, which is discussed further in this section.
[14] Maximum capacity is approximately the same as ICAP but includes some adjustments for unit availability. We use these max cap values, in combination with MISO-assigned resource adequacy values, in order to derive our UCAP totals for each resource type. These adjusted values help us to determine our net resource surplus/deficit positions, which are shown in Section I.D below.

- 1,740 MW of nuclear
- 4,740 MW of natural gas or oil-fired capacity[15]
- 2,400 MW of coal capacity

We note that the baseline resources included in our Supplement modeling have not substantially changed since our initial filing, with a few exceptions outlined below:

- *Mankato Energy Center*: In our initial filing, the Company's proposal to acquire MEC Units I and II as NSP assets was pending Commission action and the units were included in our modeling as owned assets. Ultimately the Commission denied the request to own MEC as a regulated asset and instead the Company purchased MEC as a merchant facility. The Company has since reached an agreement with Southwest Generation to sell the plant; however, it will continue to serve NSP customers under the prevailing power purchase agreements (PPAs).[16] As such, the current contract expiration dates of 2026 for MEC I and 2037 for MEC II are now reflected in our baseline modeling.
- *Crowned Ridge Wind*: Our initial filing included a 600 MW Crowned Ridge Wind facility that was scheduled to come online by 2020. The project has since been reduced to 400 MW as a result of the Seller encountering prohibitively high transmission interconnection upgrade costs associated with the last phase of the project.[17]
- *Retirement date adjustments*: We received feedback from the Commission that generating unit retirement dates in our modeling – particularly for Sherco Unit 3 – should match the units' current financial-end of-life dates. We have updated several resources' retirement dates based on this feedback.
- *Black start resources*: As we noted in our July 2019 filing, we anticipate that we will need to develop a plan for our black start resources before our next Resource Plan. These units are critical for us to be able to jumpstart the grid "from black" in the event of a widespread outage. Two black start critical units in Minnesota and Wisconsin are scheduled to retire within the planning period, but in reality, we cannot operate a system without viable black start units. While we continue to develop a robust alternatives analysis we included interim placeholder capacity in our modeling, so that we may evaluate a capacity

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[15] Not including the planned Sherco CC.
[16] *See* Docket No. E002/AI-19-622 LETTER – MANKATO ENERGY CENTER I AND II AFFILIATED INTEREST REQUEST (April 6, 2020).
[17] *See* Docket No. E002/M-16-777.

expansion portfolio that includes consideration of this future need. We discuss black start resources further in Attachment A, Section VII: Black Start.

We provide a full listing of existing resources included in our modeling in Attachment A, Section V: Resource Options.

We further note that the above totals include some renewable resources that are aligned to customer demand participating in our Windsource and R*C programs.[18] We outline these resources in Table I-2. As described below, there are two additional resources that were not yet approved by the time we locked in the resource list for modeling (as of January 31), and thus are not included in our baseline modeling for this Supplement.[19] One of these projects has since been approved and the other remains pending before the Commission at the time of this filing.

Table I-2: Windsource and Renewable*Connect Program Resources

Name	**Type**	**Size** (MW contracted)	**Program**
Existing Resources *(included in modeling)*			
Various Small Wind	Wind	Approximately 40	Windsource
Moraine II	Wind	50	Windsource
Odell	Wind	No more than 50 (partial output)	Renewable*Connect
North Star	Solar	No more than 25 (partial output)	Renewable*Connect
Recent Resources *(approved after January 31 and not included in modeling)*			
Deuel Harvest North	Wind	100	Renewable*Connect
Pending Resources *(proposed but not yet approved)*			
Elk Creek	Solar	80	Renewable*Connect

The Company files regular status updates on the R*C and Windsource programs, which include more discussion on program demand and resources. Please refer to *Annual Compliance Filing, Tracker Account Report, and Proposed 2021 Tariff Rates* (Docket No. E002/M-20-380) for R*C, and *Compliance Report and Semi-Annual Tracker Account*

[18] Note that the resources currently aligned to Windsource customers will continue to serve customers when the Windsource program sunsets and subscribers and resources are rolled into the R*C program.
[19] *See* Docket No. E002/M-19-33. IN THE MATTER OF NORTHERN STATES POWER COMPANY'S D/B/A/ XCEL ENERGY, PETITION TO EXPAND ITS RENEWABLE*CONNECT PROGRAM, *Order Approving Petition with Modifications* (August 12, 2019) at Order Point 3.

Report, Voluntary Renewable Energy Rider (Windsource) (Docket No. E002/M-01-1479) for additional details.

D. Net Resources and Capacity Surplus/Deficit

After assessing our anticipated load and MISO requirements, we compare our system-wide obligations to the resources we already have – existing or approved – on our system. As we have discussed, we expect our near-term customer load to decline, given increased EE and DR opportunities, but in the longer-term beneficial electrification growth is expected to offset some of these declines. Further, MISO has increased its PRM requirement since our initial filing. As shown below, given current unit retirement dates and existing or approved resources only, we would anticipate a net capacity surplus as measured by the MISO RA requirements through 2025, and a deficit thereafter. Our Reference Case and various baseload scenario capacity expansion plan modeling assesses potential combinations of resources that address this overall capacity deficit.

Table I-3: 2020-2034 System Net Accredited Capacity Surplus/Deficit Prior to Expansion Planning (MW, resource values measured in terms of UCAP)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
System needs															
Forecasted gross load	10,502	10,563	10,635	10,711	10,780	10,842	10,911	10,982	11,053	11,119	11,184	11,253	11,324	11,391	11,452
EV Forecast	8	12	17	25	35	44	53	65	79	99	126	163	214	273	336
Forecasted EE[20] (reduction to load)	(1,395)	(1,508)	(1,550)	(1,625)	(1,723)	(1,817)	(1,907)	(1,975)	(2,052)	(2,189)	(2,269)	(2,367)	(2,448)	(2,521)	(2,583)
Forecasted net load	9,115	9,067	9,101	9,111	9,092	9,068	9,057	9,072	9,080	9,029	9,041	9,049	9,090	9,143	9,205
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,659	8,614	8,646	8,655	8,638	8,615	8,604	8,618	8,626	8,578	8,589	8,597	8,636	8,686	8,745
MISO PRM	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%
NSP Obligation	9,430	9,380	9,416	9,426	9,406	9,382	9,370	9,385	9,393	9,341	9,354	9,362	9,404	9,459	9,523
Existing and approved resources (UCAP)															
Load Management *(existing)*	1,012	1,027	1,041	1,055	1,066	1,072	1,077	1,078	1,077	1,071	1,059	1,048	1,037	1,026	1,016
Load Management *(potential study)*	33	165	232	294	341	382	394	407	423	440	458	478	499	521	545
Coal	2,295	2,295	2,295	2,295	1,647	1,647	1,647	994	994	994	994	994	994	994	994
Nuclear	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,019	1,019	1,019	498	0
Natural Gas/Oil	3,858	3,858	3,858	3,858	3,713	3,403	3,112	2,831	2,831	2,831	2,831	2,288	2,012	2,012	2,012
Sherco CC	0	0	0	0	0	0	0	728	728	728	728	728	728	728	728
Biomass/RDF	110	110	110	86	86	61	61	61	29	29	29	19	19	19	19
Hydro	881	1,001	993	993	993	162	162	162	162	162	162	162	156	152	152
Wind	498	623	672	647	635	631	626	611	605	583	582	566	563	498	479
Grid-scale solar	129	129	128	127	122	116	110	105	99	94	88	83	78	73	72
Solar*Rewards Community Solar	329	357	394	421	409	392	376	359	343	326	309	292	276	259	259
Distributed Solar	37	45	53	60	64	68	71	74	76	78	78	79	78	77	81
Existing Resources	10,824	11,252	11,418	11,478	10,717	9,576	9,278	9,052	9,007	8,976	8,338	7,757	7,459	6,857	6,358
Net Resource (Need)/Surplus	1,394	1,871	2,002	2,052	1,311	195	(92)	(334)	(386)	(365)	(1,016)	(1,605)	(1,945)	(2,602)	(3,166)

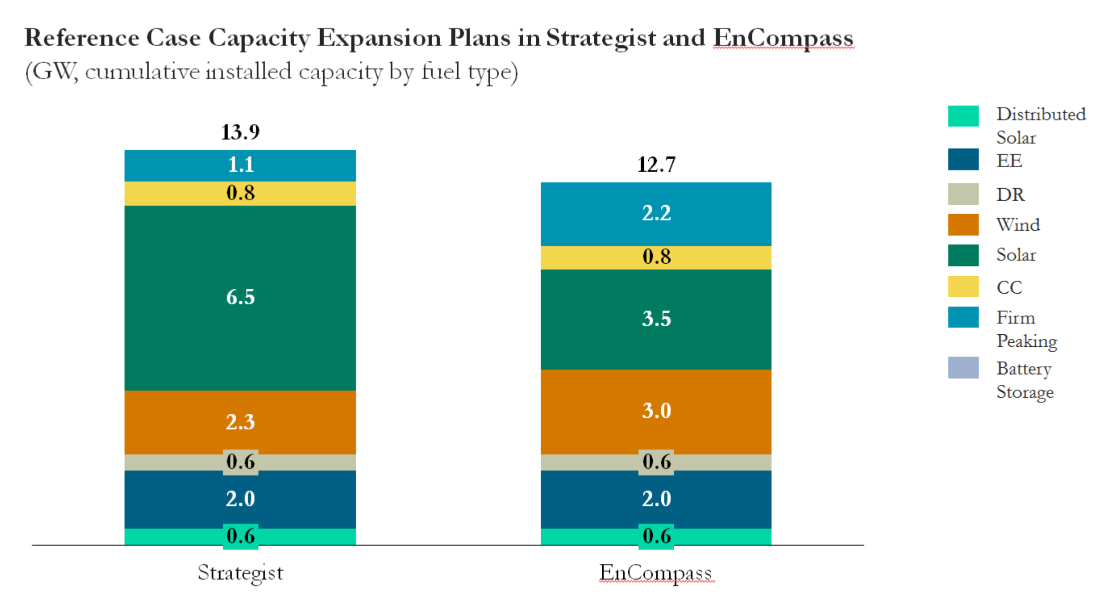
E. Reference Case Results

After establishing the net surplus/deficit, we then begin modeling our future capacity expansion portfolios around "baseload scenarios," which test combinations of baseload unit retirement dates. Our Reference Case – or Scenario 1, to which we compare all other scenarios – reflects baseload unit retirement dates as they stand today. Our other baseload scenarios test different combinations of retirement dates to examine whether a different approach may benefit customers by reducing the net present value of costs associated with the resulting portfolio of capacity additions.

[20] Includes EE savings from historically installed measures, as well as future EE from bundles modeled in this Resource Plan, achieving 2-3% savings levels.

As discussed in this filing, the Company has modeled baseload scenarios both in Strategist – our legacy forecasting tool – as well as the new EnCompass model. Because these models use distinctly different approaches to arrive at capacity expansion plans, they also come to different conclusions regarding optimal future portfolios and energy dispatch. As illustrated in Figure I-7 below, the Strategist Reference Case expansion plan includes a substantial amount of solar capacity additions whereas the EnCompass model's Reference Case selections reflect less capacity overall and a more balanced portfolio of additions across wind, solar and firm peaking capacity.

Figure I-7: Reference Case Capacity Expansion Plans



Both the Strategist and EnCompass Reference Case capacity expansion plans result in high levels of renewable and carbon-free energy on our system by 2034. Strategist modeling shows the Reference Case achieving 76 percent carbon-free energy by 2034, up from 60 percent in 2020. The EnCompass capacity expansion plans result in the Reference Case achieving 71 percent carbon-free energy by 2034, up from 56 percent modeled in 2020. The 2020 share of carbon-free energy differs as a result of the models' different approaches to system dispatch.

Figure I-8: Reference Case Energy Mix in 2020 and 2034, from Strategist

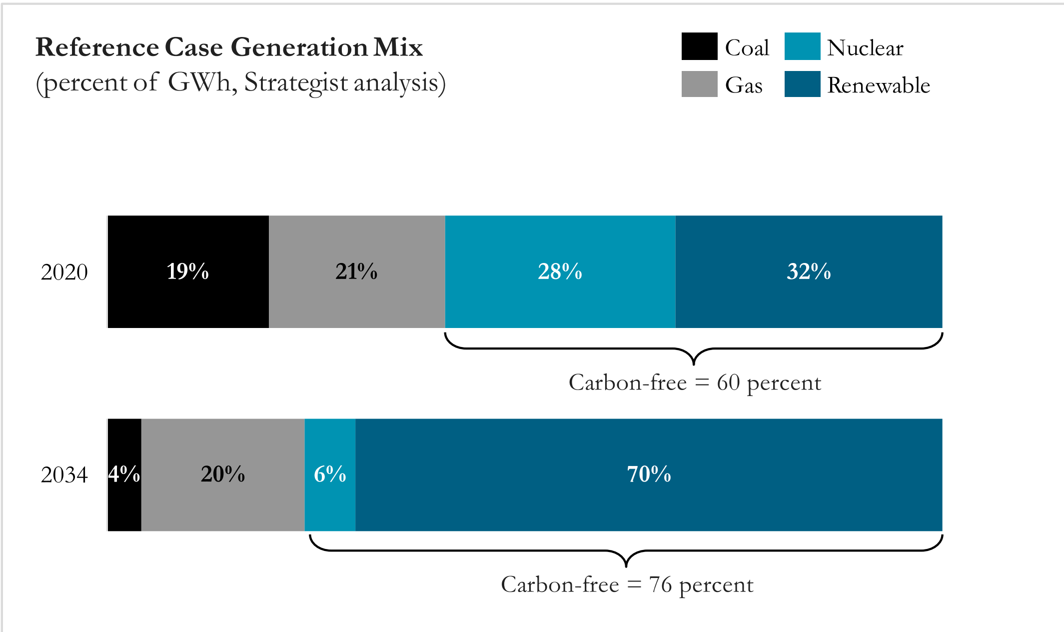
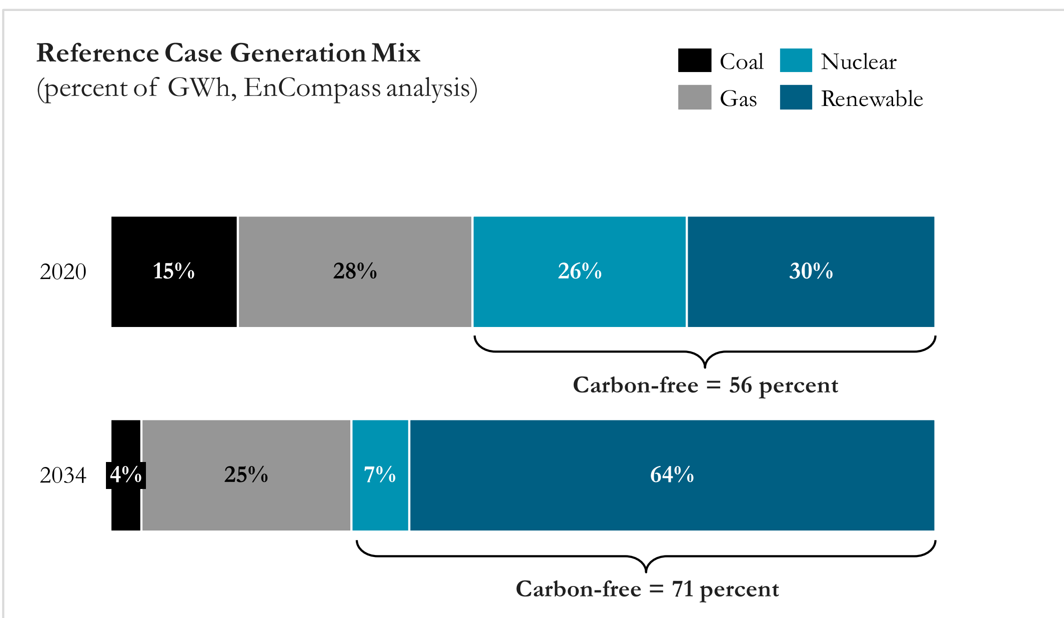


Figure I-9: Reference Case Energy Mix in 2020 and 2034, from EnCompass



II. LOAD FORECAST

This Section discusses the methodology we used in conjunction with this Resource Plan to forecast customer need. The underlying econometric models and statistical techniques used in our initial Plan in July 2019 have not changed, so we do not address them in detail in this Supplement.[21] Further, we continue to make adjustments in order to appropriately align our corporate load forecasting methods with Resource Plan objectives of modeling demand-side resources in competition with generic supply-side resource options, such that both types of resources are evaluated for inclusion into our Supplement Preferred Plan on an economic basis. This section discusses the outcomes of our energy and demand-side resource forecasting.

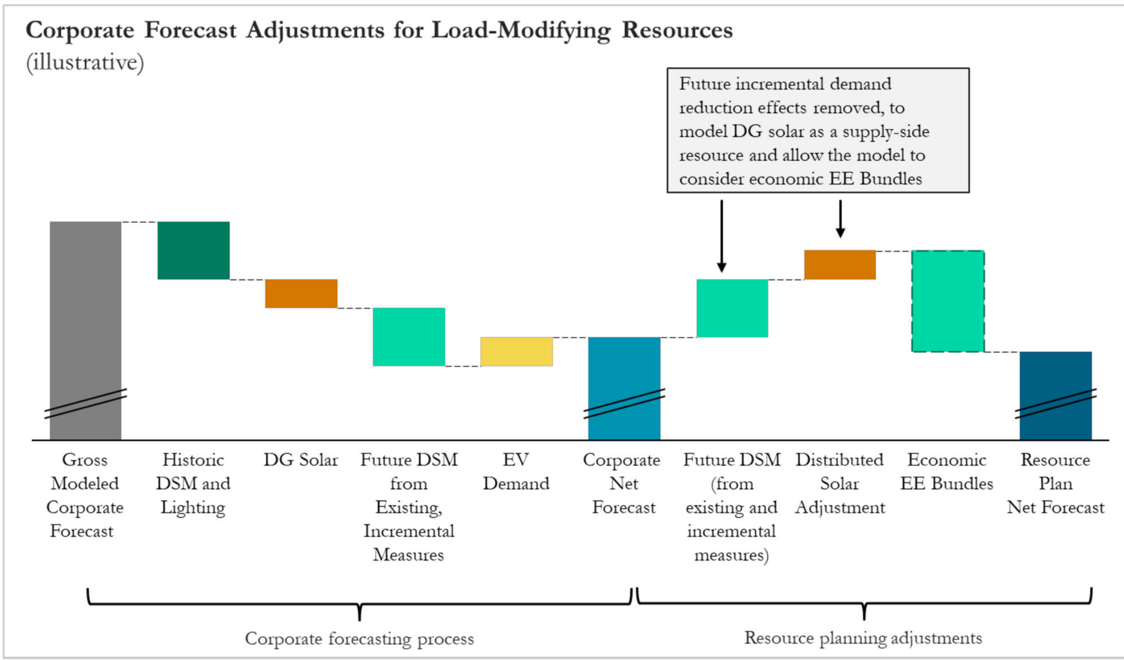
At a high level, the Company relies on econometric models and other statistical techniques to develop the sales forecast. The econometric models relate our historical electric sales to demographic, economic and weather variable data. For example, we use projections of economic activity for our various service areas that are provided by IHS Markit Inc. (formerly IHS Global Insight, Inc.). Based on this and other inputs, we develop sales forecasts for each major customer class, in each state of our service area. The individual class forecasts for each state are summed to derive a total system sales forecast. We then convert the sales forecast into energy requirements at the generator level by adding energy losses. The forecasted losses are based on forecasted loss factors, which are developed using actual historical loss factors and are held constant over the forecast period. We develop the peak demand forecast using a regression model that relates historical monthly base peak demand to energy requirements and weather. The median energy requirements forecast and normal peak-producing weather are used in the model to create the median base peak demand forecast.

We note that the corporate forecasts described in this section are adjusted before they are used in Strategist and EnCompass modeling, so that we can allow the model to evaluate demand-side resources – such as incremental EE and distributed solar (or DG Solar) – against supply-side resources in the Strategist and EnCompass modeling processes. We also test different levels of incremental demand from electric vehicles (EV) in sensitivities, later in the modeling process. The corporate forecast adjustment process for use in resource plan modeling is further illustrated in Figure II-1 below. This section focuses primarily on discussing corporate forecast methodology

[21] Please refer to Appendix F1 of our initial filing for a detailed discussion of load forecasting methodologies.

development, with notes regarding adjustments for use in resource plan modeling where relevant.

Figure II-1: Illustrative Adjustments to Translate Corporate Forecasts to Resource Plan Model Inputs



Finally, we note that the recent COVID-19 pandemic and associated economic slowdown has certainly affected the overall amount and patterns of our customers' energy consumption. We are continuing to monitor these changes; however, it is too soon to attempt to capture the potential long-term effects in the forecasts underlying this Supplement.

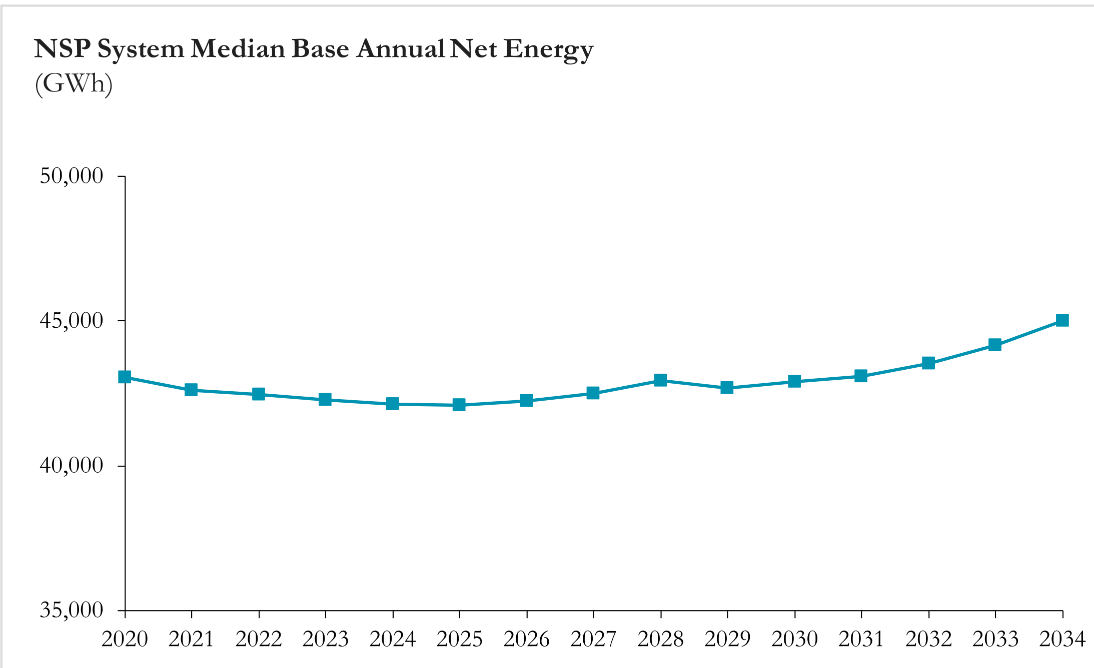
A. Energy Forecast

1. *Base Forecast Methodology*

Our updated base energy forecast increases at an average annual growth rate of 0.2 percent over the 2020 – 2034 planning period, net of approximately the same amount of energy efficiency (EE) savings levels included in our initial Preferred Plan, as well as updated forecasts for distributed solar energy production, and electric vehicle charging consumption.

Taking these adjustments into account, the base forecasted electric energy requirements are expected to increase at an annual average of 140 gigawatt-hours (GWh), growing from approximately 43,000 GWh in 2020 to 45,000 GWh in 2034. See Figure II-2 below.

Figure II-2: NSP System Total Median Net Energy



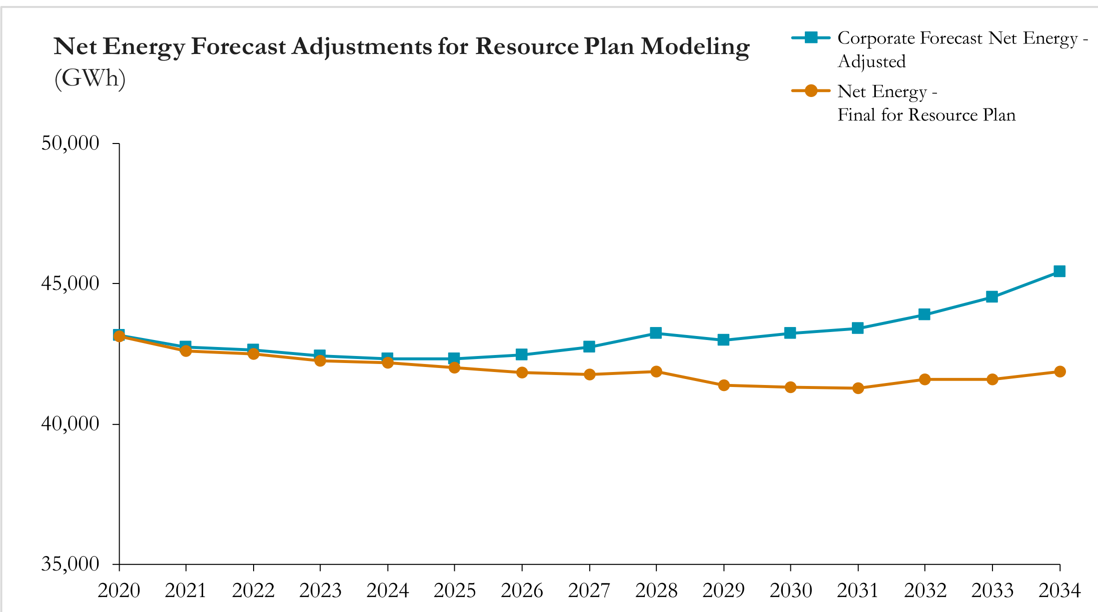
We note that the projected 0.2 percent average annual growth in electric energy requirements is stronger than the actual growth seen over the past few years. After adjusting for unusual weather, electric energy requirements *decreased* at an average annual rate of 0.2 percent from 2014 to 2018.

2. *Modifications for Use in Resource Plan Modeling*

As noted above, we undertook additional steps in the course of resource plan modeling, in order for incremental new EE to be modeled as a supply-side resource. This required that we adjust the base energy forecast (discussed in Part 1 above) to remove the embedded EE adjustment that projects the effects of new 2020-2034 program year EE achievements. We also disaggregated DG Solar resources, as discussed previously. We then included incremental potential EE savings amounts from the 2020-2034 program years in Strategist and Encompass modeling processes as "Bundles," which compete on an economic basis with supply-side resources. In effect, this allows us to treat projected additions of DG solar and portfolios of new EE measures, at a given average cost, like generic supply-side resources.

Given the first two EE bundles were shown to be economic in our initial modeling (as filed in July 2019), we have included them in our baseline modeling in this Supplement. As a result of these adjustments, the net forecast for Resource Plan modeling declines across the modeling period, as compared to the corporate forecasts, as reflected in Figure II-3 below.

Figure II-3: Net Energy Requirements Forecast Adjustments for Resource Plan Modeling[22]



We discuss the EE Bundle modeling further in Attachment A, Section IV: Modeling Inputs and Assumptions and Attachment A, Section V: Resource Options.

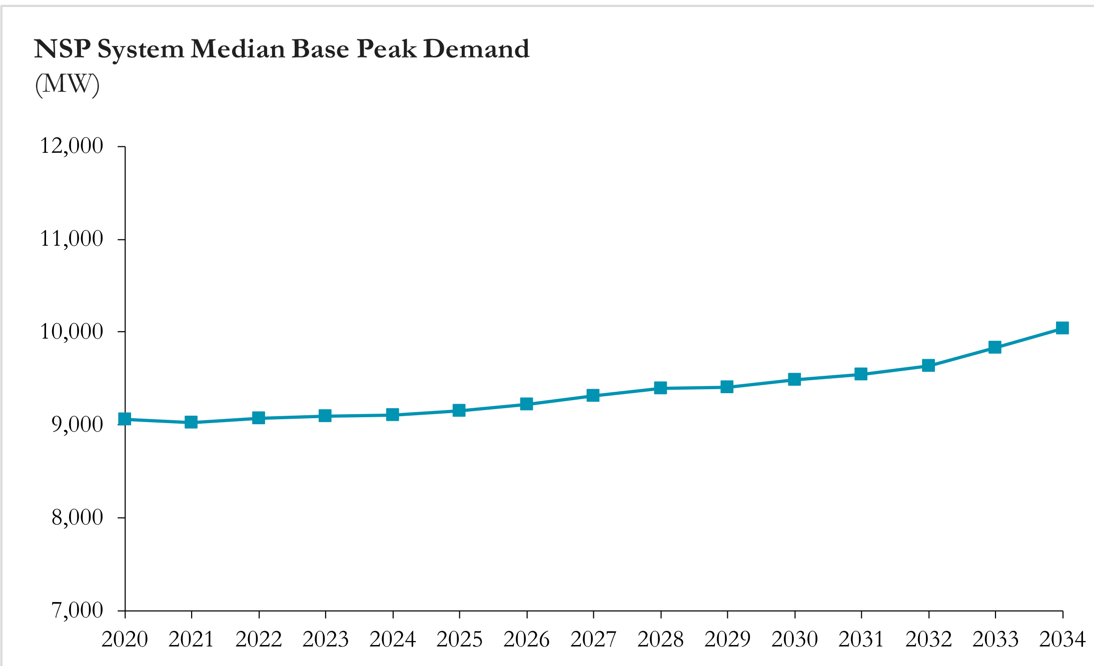
[22] Corporate Forecast Net Energy Adjusted represents the base corporate forecast further adjusted to model distributed solar as a supply-side resource.

B. System Peak Demand Forecast

1. *Base Forecast Methodology*

During the 2020-2034 planning period, the median base peak demand corporate forecast increases at an average annual growth rate of 0.7 percent, when including effects of already assumed EE. As demonstrated in Figure II-4 below, annual peak demand increases at an average of 66 MW each year, starting with just over 9,000 MW in 2020 to just under 10,000 MW in 2034.

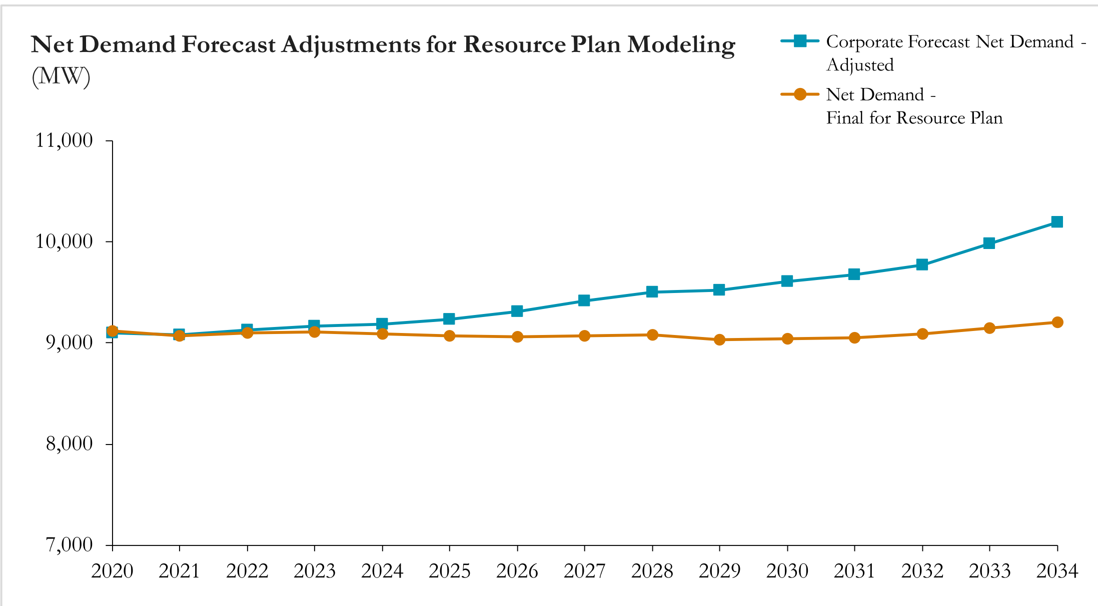
Figure II-4: NSP System Median Base Summer Peak Demand



2. *Modifications for Use in Strategist*

For modeling demand levels in Strategist, we took the same approach as noted in reference to the energy forecasts. Again here, for Strategist modeling purposes, we start with the corporate forecast and remove the effects of future incremental 2020-2034 program year EE adjustments, but then include the first two EE bundles in our net forecast for use in Resource Plan modeling. This process enables us to evaluate how EE Bundles can compete with supply-side resources in our modeling. We also make adjustments for DG solar. The net effect of this adjustment reduces forecasted demand relative to the corporate forecasts.

Figure II-5: Net Peak Demand Forecast Adjustments for Resource Plan Modeling[23]



C. Key Demand and Energy Forecast Variables

The balance of this section discusses the energy and peak load forecasting methods, assumptions, analytics, adjustments, etc. to derive the Corporate System Energy Forecast presented above. In general, our approach to modeling energy and capacity demand forecasts is consistent relative to our initial filing, even as some inputs and assumptions have been updated.

1. *Demographics*

Demographic projections are essential to the development of the long-range forecasts. The consumption of electricity is closely correlated with demographic statistics. The number of residential customers, weather data and economic indicators are key variables in the residential energy sales forecast. Over 99 percent of the variability in

[23] Corporate Forecast Net Demand - Adjusted represents the corporate forecast further adjusted to model distributed solar as a supply-side resource.

historical electric residential customer counts in our service territory can be explained through an econometric model that contains either population or households as key drivers. The forecasts for population and households are provided by IHS Markit Inc.

We forecast an average annual growth rate for total residential customers on our system of 0.6 percent, with the addition of 9,922 residential customers on average per year from 2020 through 2034.

2. Economic Indicators

Xcel Energy uses estimates of key economic indicators to develop electric sales forecasts. These variables include gross state product, employment and real personal income. The variables used are specific to the jurisdiction and are statistically significant in the sales models for the residential and commercial and industrial customer classes. Growth in electric energy consumption in the residential and commercial and industrial sectors closely follows trends in economic activity. IHS Markit Inc. provided the economic forecasts used in our regression models.

For the planning period, the economy is expected to continue to grow, resulting in growth in electric energy consumption.

3. Weather

The peak demand for electric power is heavily influenced by hot and humid weather. As the temperature and humidity rise, the demand for cooling rises steeply. Our approach to forecasting peak demand includes using a weather variable that consists of the mean of an index of heat and humidity referred to as the temperature humidity index (THI). Simply stated, the THI is an accurate measure of how hot it really feels when the effects of humidity are added to the high temperature.

We have tracked the THI at the time of the system peak demand over the past 20 years. Because of the 20 years of smoothing, the weather variable does not drastically affect our median forecasts; however, it becomes a key factor in assessing the potential peak demand if and when hot and humid weather extremes are encountered. Since Xcel Energy must have adequate generating resources available during hotter than normal circumstances, planning for the extreme is important.

D. Forecast Methodology

Xcel Energy serves customers in five jurisdictions in the upper Midwest: Minnesota, North Dakota, South Dakota, Wisconsin and Michigan. We develop a forecast for each major customer class and jurisdiction using a variety of statistical techniques.

We first develop our system sales forecasts by using a set of econometric models at the jurisdictional level for the Residential and Small Commercial and Industrial sectors for all jurisdictions, the Large Commercial and Industrial sector for Minnesota, and the Minnesota Public Street and Highway Lighting and Public Authority sectors. These models relate our historical electric sales to demographic, economic and weather variables as detailed in the prior section of this document.

For the remaining customer classes, Large Commercial and Industrial, Public Street and Highway Lighting, and Public Authority in all states but Minnesota, and Interdepartmental, we use trend analysis and customer specific data. We compile our system sales by summing the individual forecasts for each sector in each jurisdiction.

Since some energy is lost, mostly in the form of heat created in transmission and distribution conductors, we use loss factors to convert the sales forecasts into energy production requirements at the generator. The forecasted loss factors are developed using actual historical loss factors and are held constant over the forecast period.

We have developed a regression model to relate Xcel Energy's historical uninterrupted monthly peak demand to energy requirements and weather at the time of the peak in the winter and summer seasons. The median energy requirements forecast (50/50 forecast) and normal peak-producing weather are used in the model to create the peak demand forecast.

Once the NSP System peak demand forecast is complete, a forecast is developed for the NSP System demand coincident with the MISO system peak demand. The coincident demand forecast is developed using a regression model that determines the relationship between the NSP System demand coincident with the MISO peak demand and the NSP System peak demand (not coincident with the MISO peak demand). MISO only requires an annual coincident demand forecast for the next planning year. The current resource plan forecast uses the NSP System demand coincident to the MISO annual peak demand during the 2020-21 planning year (June 2020 – May 2021).

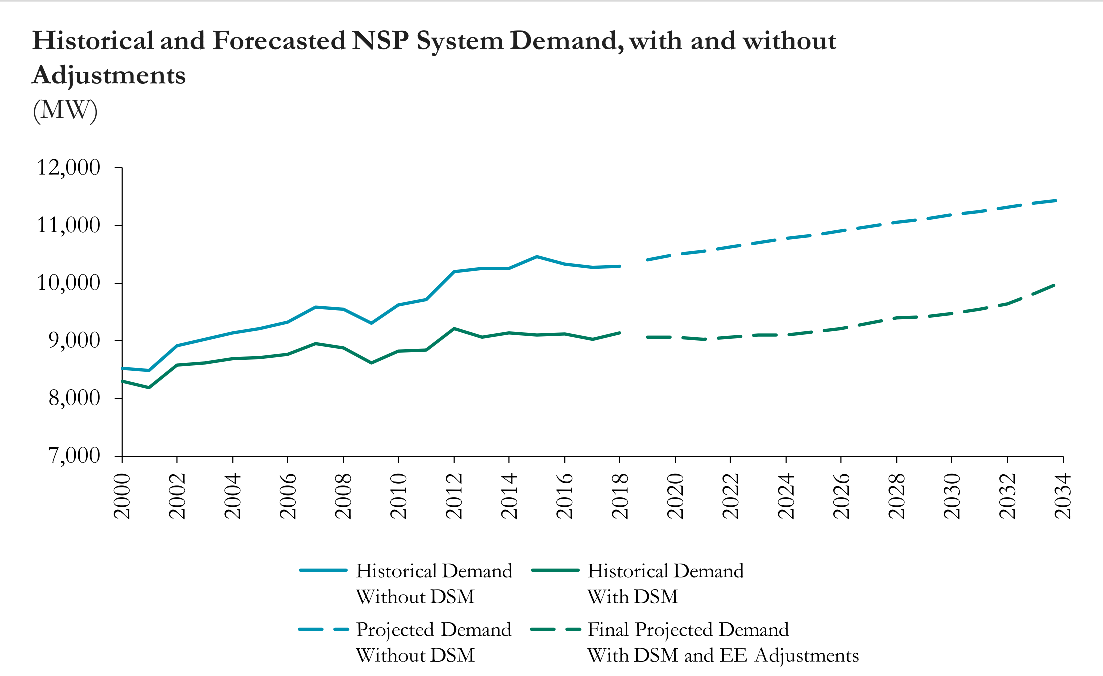
E. Corporate Forecast Adjustments

Our demand and energy forecasts are developed using a number of key forecast variables as described in this section. One important adjustment to the forecasts is to take into account our conservation programs.

The EE methodology implemented for the State of Minnesota uses the same method for projecting the impacts of EE and its load management effects on the sales forecast as was used in our 2015 Resource Plan filing. There are three distinct steps to this process:

- Collect and calculate historical and current effects of EE on observed sales;
- Project the forecast using observed data with the impact of EE removed (i.e. increase historical sales to show hypothetical case without EE); and
- Adjust the forecast to show the impact of all planned EE in future years (and further adjust the forecast to account for codes and standards changes resulting in decreased sales that are in addition to Company-sponsored EE).

Figure II-6: Illustration of EE Adjustment – NSP System Demand



For the State of South Dakota, the impacts from all conservation program installations prior to 2019 are assumed embedded in the historical demand and energy data at a rate equal to the annual program installations from 2014 through 2018. To accurately predict future supply needs, the energy and demand forecasts must be reduced by an estimate of the incremental future conservation savings. For the base forecast, we adjust the demand and energy forecast by assuming all future annual conservation achievement equal to achievement of our 2019 goal as approved in the 2017 South Dakota DSM Status Report and 2019 DSM Plan filing (Docket No. EL18-023).

In response to the establishment of a Solar Energy Standard (SES) by the Minnesota Legislature, an increased emphasis has been placed on distributed solar generation. We developed a forecast of the expected impact on demand and energy based on new programs designed to meet goals established for the SES. We adjusted the Minnesota class-level sales forecasts and the system peak demand forecast to account for the impacts of customer-sited behind-the-meter solar installations on the NSP System. We discuss the distributed solar forecast methodology below.

After determining the base forecast, we develop net forecasts that include all adjustments, including future EE, distributed solar generation, electric vehicle charging, and the effects of our EE programs over time.

F. Additional Forecast Adjustments

We made additional adjustments to the energy and demand forecasts to account for expected changes in specific large customers' electricity usage. These additional adjustments include:

- Customers adding self-generation combined heat and power capabilities, which reduce energy consumption and peak demand; and
- Increases or reductions in usage due to new customers in our service territory, or planned expansions or reductions of load by existing customers, and increasing use of plug-in electric vehicle charging, which we discuss in Part II.D below.

G. Forecast Variability

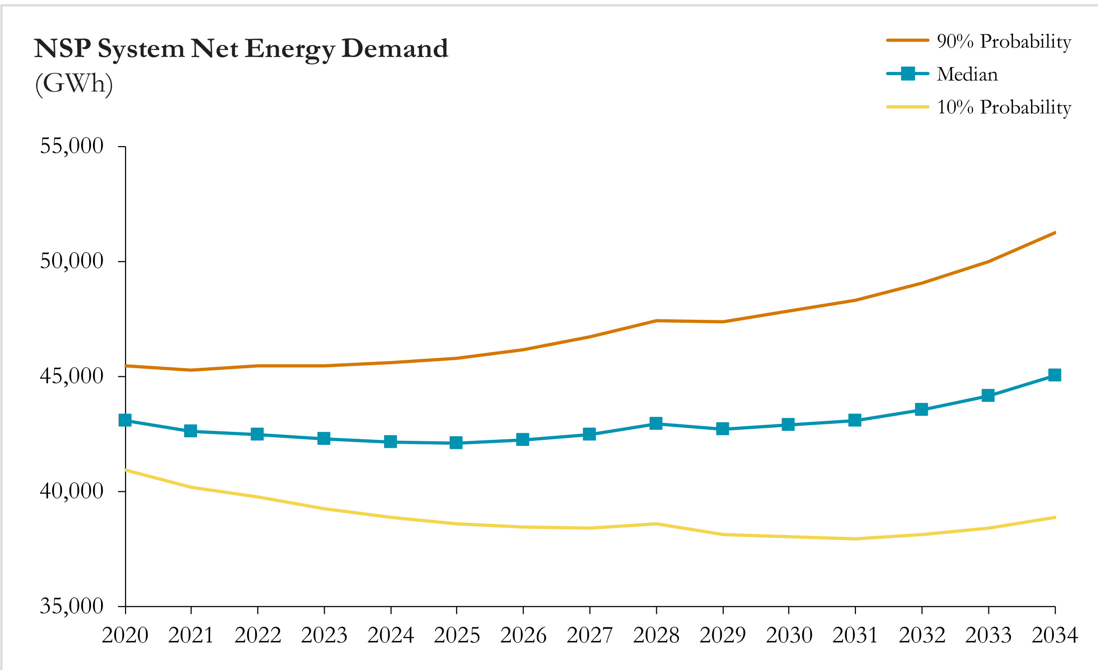
As with any forecast, our forecasts of energy requirements and peak demand depend on other forecasts of key variables. Changes in these variables will affect our forecasts. For instance, if the number of households in our service territory is lower than IHS Markit Inc. has predicted, electric consumption in the residential sector will be lower. The peak demand for electric power each year is very sensitive to weather conditions and can vary considerably as the result of abnormal weather conditions.

Other forecast uncertainties include potential increases in loads due to new customers and potential losses in loads due to changes in customers' operations. For example, the potential exists for large increases in loads in the middle of the planning period due to increased mining activities in Northern Wisconsin. However, at this time, there is still uncertainty around this potential increase and, therefore, we have not made an adjustment to the forecast.

Given that there is uncertainty in any long-term forecast, we supplement the median forecasts with forecasts developed using statistical techniques to reflect the potential variability in energy requirements and peak demand. These probability distributions were developed using a Monte Carlo stochastic simulation of peak demand (MW) and energy (MWh). For example, the peak demand simulation involved taking 10,000 random draws from the weather probability distributions as well as 10,000 random draws from the 12-month sum of the energy probability distribution. The random draws produce 10,000 forecasts of peak demand and thus generate a probability distribution around the mean peak demand.

The probability distributions developed for this forecast yielded a 90 percent probability that the net energy will be less than 51,261,533 MWh in 2034 – or alternatively, there is a 10 percent probability that the net energy will be less than 38,887,528 MWh. See Figure II-7 below.

Figure II-7: NSP System Total Net Energy



Figures II-8 and II-9 below show the higher and lower variations of the 2020 to 2034 long-range forecasts of base and net summer peak demand. [24]

[24] Where net summer peak demand includes adjustments form the base forecast to account for interruptible load.

Figure II-8: NSP System Total Base Summer Peak Demand

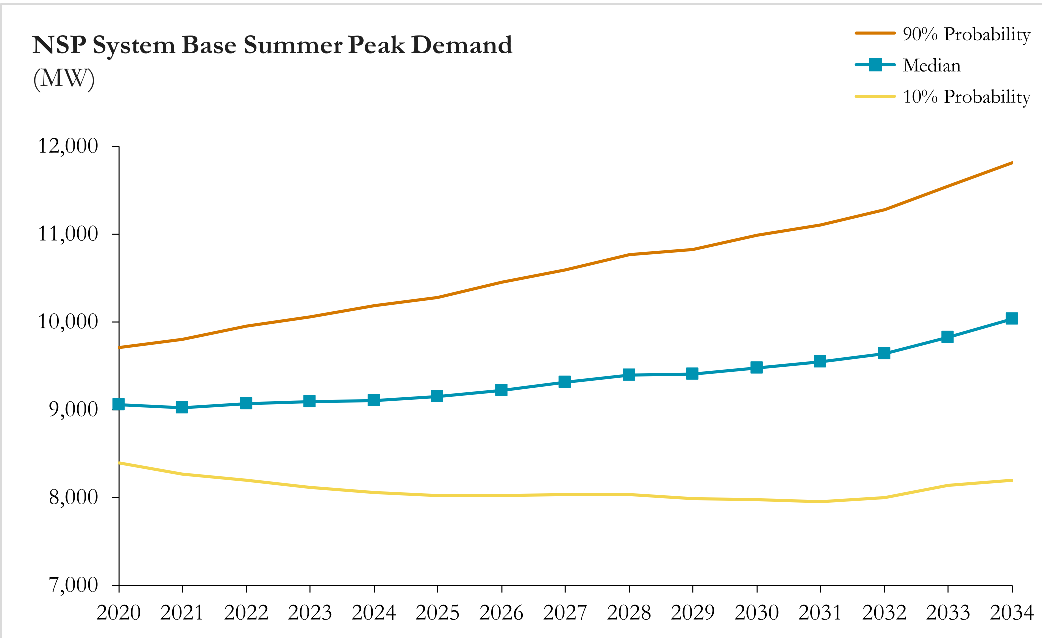
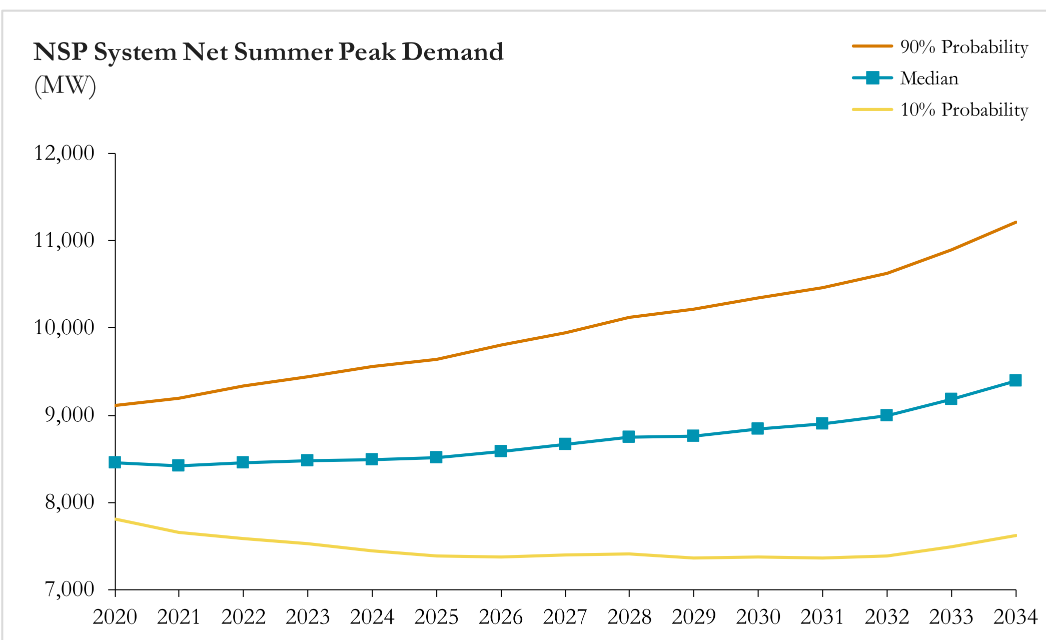


Figure II-9: NSP System Total Net Summer Peak Demand



Tables II-1, II-2, and II-3 below provide the data underlying Figures II-7, II-8, and II-9, respectively.

Table II-1: Annual Net Energy (MWh)

Year	90% Probability	Median	10% Probability
2020	45,476,686	43,061,970	40,919,797
2021	45,272,408	42,606,809	40,164,021
2022	45,442,181	42,471,834	39,760,912
2023	45,448,683	42,262,626	39,266,438
2024	45,581,547	42,140,430	38,885,430
2025	45,789,703	42,103,713	38,605,884
2026	46,162,866	42,228,105	38,463,143
2027	46,704,396	42,493,983	38,416,797
2028	47,415,952	42,936,296	38,585,387
2029	47,382,221	42,700,049	38,113,206
2030	47,855,827	42,896,785	38,043,364
2031	48,291,300	43,072,712	37,948,552
2032	49,077,682	43,533,978	38,132,993
2033	49,989,767	44,142,411	38,395,001
2034	51,261,533	45,016,323	38,887,528
Average Annual Growth 2020 - 2034	**0.9%**	**0.2%**	**-0.6%**

Table II-2: Annual Base Summer Peak Demand (MW)

Year	90% Probability	Median	10% Probability
2020	9,704	9,058	8,390
2021	9,799	9,028	8,268
2022	9,952	9,066	8,196
2023	10,062	9,097	8,114
2024	10,186	9,108	8,053
2025	10,284	9,154	8,020
2026	10,452	9,219	8,018
2027	10,596	9,313	8,033
2028	10,762	9,396	8,041
2029	10,831	9,409	7,985
2030	10,991	9,480	7,980
2031	11,105	9,546	7,954
2032	11,276	9,634	7,996
2033	11,543	9,830	8,139
2034	11,811	10,033	8,201
Average Annual Growth 2020 - 2034	**1.4%**	**0.7%**	**-0.3%**

Table II-3: Annual Net Peak Demand (MW)

Year	90% Probability	Median	10% Probability
2020	9,112	8,457	7,812
2021	9,190	8,419	7,659
2022	9,336	8,452	7,587
2023	9,441	8,477	7,526
2024	9,563	8,486	7,447
2025	9,634	8,514	7,383
2026	9,800	8,579	7,377
2027	9,947	8,669	7,395
2028	10,118	8,752	7,405
2029	10,216	8,765	7,365
2030	10,347	8,836	7,369
2031	10,461	8,902	7,365
2032	10,632	8,990	7,383
2033	10,899	9,186	7,495
2034	11,208	9,389	7,620
Average Annual Growth 2020 - 2034	**1.5%**	**0.7%**	**-0.3%**

H. Forecast Vintage Comparison

As described above, projections of energy and demand are fundamental to identifying the need for resources to meet expected customer needs. Thus, these forecasts are an important component in determining the size, type and timing of new generation resources. As a result, ensuring robust forecasts with fully analyzed assumptions and variables is a key component to supporting a Resource Plan or resource acquisition.

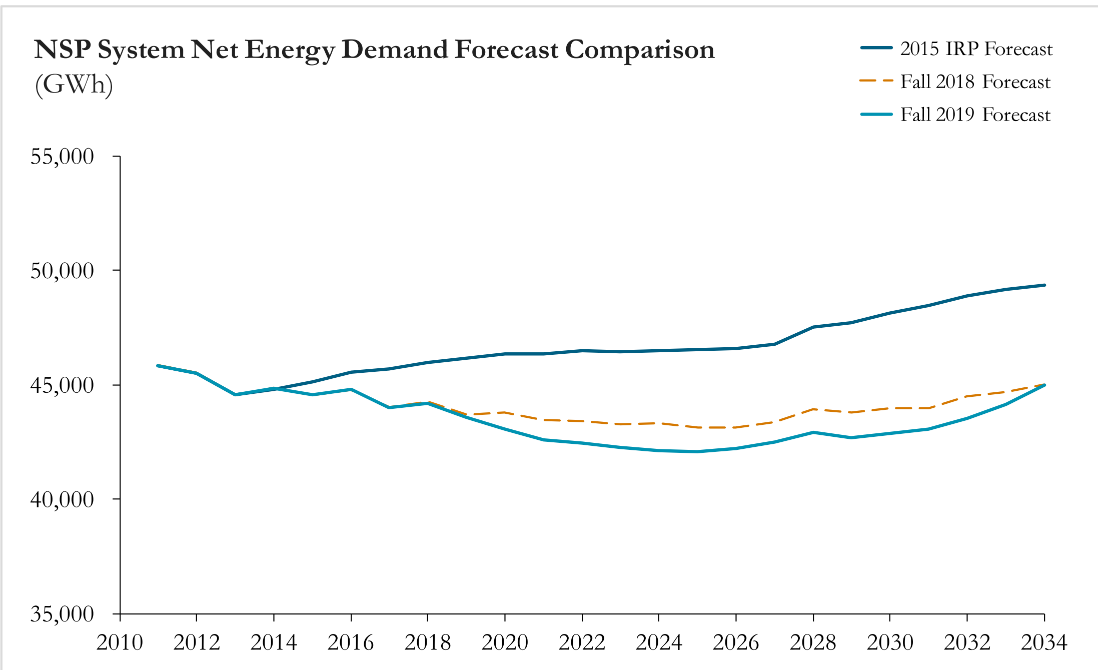
1. *Forecast Vintage and Comparison*

The review process for a Resource Plan or a resource acquisition typically takes a significant amount of time and effort to complete. During this time, forecasts can change as economic conditions, business operations, and technology changes occur. The graphs below compare the peak demand and energy of the Company's fall 2019 forecast with both the forecasts filed 2015 Resource Plan and the forecasts filed in our Initial 2020-2024 Resource Plan.

Figure II-10 below indicates that the fall 2019 energy forecast is lower than the fall 2014 forecast provided in our 2015 Resource Plan due to lower and declining actual sales in 2015, 2016, 2017, and 2018. In particular, 2015-2018 weather normalized actual sales were lower for the NSP Minnesota (NSPM) residential sector and the NSPM small and large commercial and industrial sectors. In the residential sector, while the actual number of customers was slightly higher than estimated in the fall 2014 forecast, the larger driver of the weaker-than-expected sales was lower use per customer. The NSPM small commercial and industrial sector also experienced lower-than expected use per customer. The NSPM large commercial and industrial sector was projected to grow in the fall 2014 forecast, but actual sales declined due to customers installing combined heat and power plants and loss of other load to locations outside Xcel's service territory.

The fall 2019 forecast is also slightly lower than fall 2018 forecast, used in our Initial filing in this docket. There are several factors influencing these adjustments. First, we experienced lower than expected weather-normalized sales from June 2018 through May 2019, the 12-month period between when the fall 2018 forecast was developed and when the fall 2019 forecast was developed. Further, our fall 2019 forecast vintage anticipates additional energy efficiency savings going forward relative to the fall 2018 forecast. We have also adjusted expectations around small commercial and industrial class sales during the interval between the fall 2018 and fall 2019 forecasts. For example, the fall 2019 forecast was adjusted to remove specific large commercial and industrial load expansions plans that were anticipated in the fall 2018 forecast but later canceled. Finally, the fall 2019 forecast vintage anticipates increased load from electric vehicle adoption in the out years of the forecast, exhibited by a steeper growth trajectory after 2030.

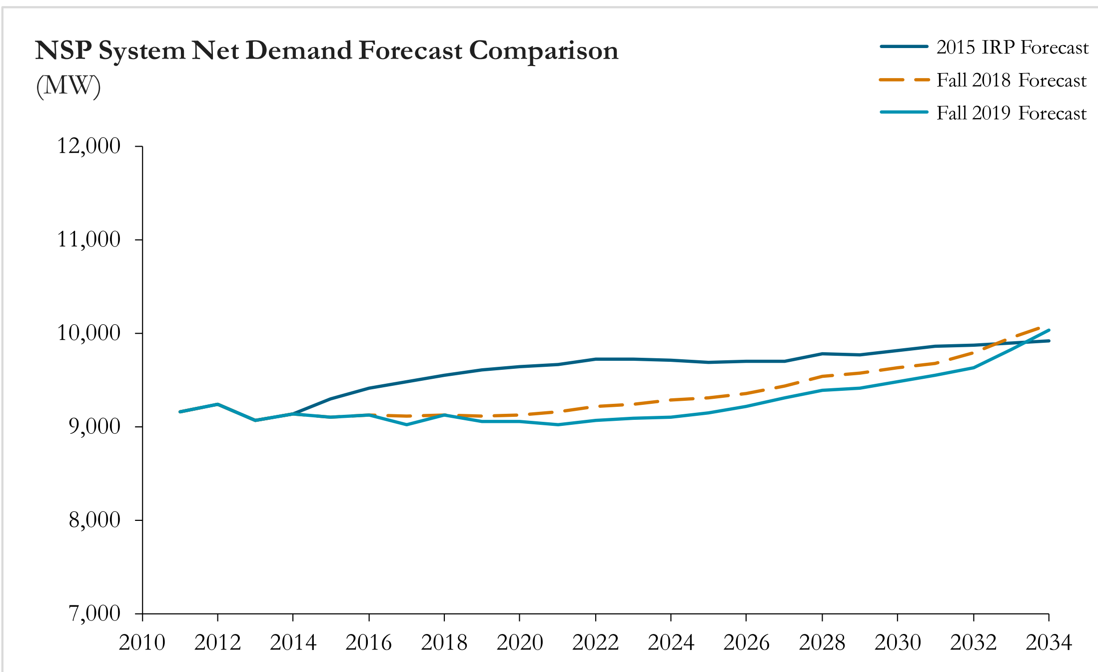
Figure II-10: Net Energy Requirements– Comparison of Current and Previous Energy Forecast Median (50th Percentile) Forecast



In addition, the projected rate of growth of key economic indicators is lower now than when the fall 2014 forecast was produced. For example, the average annual growth rate during the planning period for Minnesota real personal income is 1.8 percent, compared to a projected 3.6 percent in the fall 2014 forecast. As another example, the average annual growth rate during the planning period for Minneapolis-St. Paul total employment is 0.6 percent, compared to the projected 1.1 percent in the fall 2014 forecast.

Figure II-11 below shows a comparison of the fall 2019 base peak demand forecast to the fall 2014 and 2018 forecasts. Similar to the energy forecast, the current demand forecast is lower than the fall 2014 forecast underlying the 2015 Resource Plan for most of the planning period. While actual sales from 2011 to 2018 have trended downward, the NSP system peak demand has remained fairly flat, but below the fall 2014 forecast. The current forecast calls for peak demand to increase and surpass the fall 2014 forecast as energy gains turn positive in the outer years of the planning period. As discussed above, the fall 2019 peak forecast is lower than the fall 2018 forecast due to the lower sales forecast. However, by the end of the planning period, the fall 2019 forecast returns to the level of the fall 2018 peak forecast, as a result of anticipated growing electric vehicle load.

**Figure II-11: Base Peak Demand – Comparison of Current and Previous Demand Forecast
Median (50th Percentile) Forecast**



III. DISTRIBUTED ENERGY RESOURCE FORECASTS

This section discusses the DER forecasts used in our Supplement analyses.

A. Distributed Solar

We offer several programs to customers who are interested in distributed solar. Specifically, we provide incentives under our Solar*Rewards program, and the opportunity to earn bill credits for community solar gardens in our Solar*Rewards Community program. Until its discontinuance, Minnesota customers also had the opportunity to participate in the Made in Minnesota program. Customers may also choose a net metered option for on-site solar. Both our Reference and High adoption forecast cases take all these programs into account, at varying growth rates.

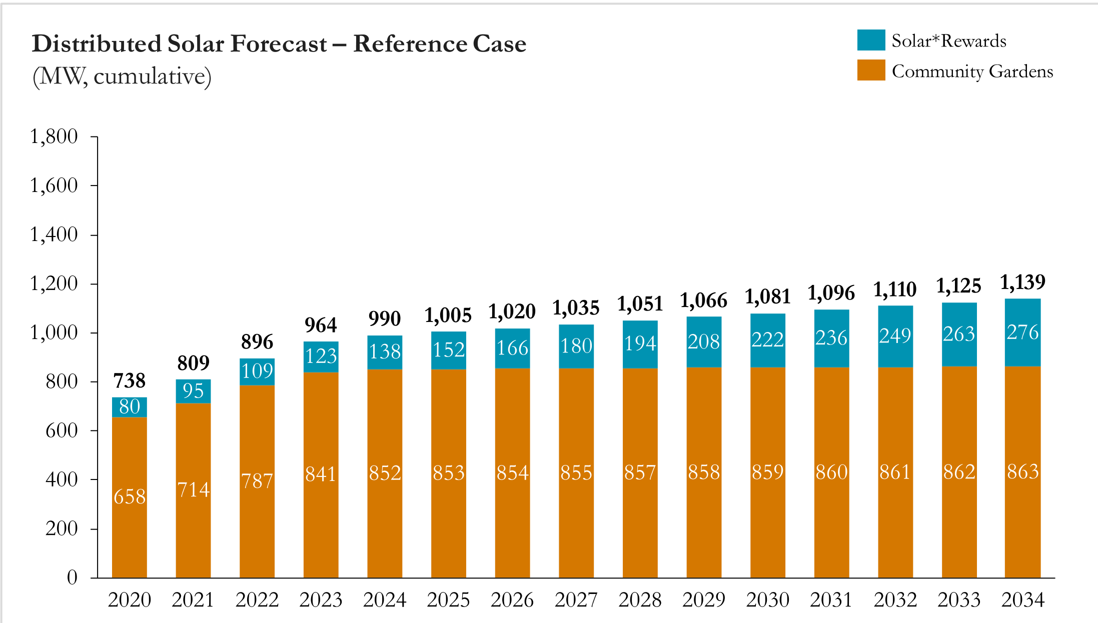
1. Reference Case

In determining our Reference Case, we updated our forecasted adoption levels to be consistent with 2017 legislative outcomes that: 1) increased 2018-2020 Solar*Rewards incentive funding, 2) eliminated new Made in Minnesota awards after 2017, with final installations completed by October 2018, and 3) eliminated new Solar*Rewards systems after 2021, with final installations completed by 2023. We assumed net metering-only system additions would continue at current annual levels through 2021 and increase in 2022 to accommodate for demand from the elimination of the Solar*Rewards program. We based attrition and completion lag rates on historical analysis of cancelled and completed projects, and subsequently applied them to program application forecasts to derive final installation estimates.

Due to the large response to date for our Solar*Rewards Community program – which has no statutory budget or capacity limits – we forecast additions of 738 MW through 2020. For our Reference Case assumptions, we assume DG solar grows at approximately 15 MW per year after 2023. This assumption takes into account significant early adoption of Community Solar Gardens (CSGs) and a going-forward reduction in tax benefits. These projections are consistent with those included in our 2019 Integrated Distribution Plan (IDP).

Figure III-1 below provides our Reference Case forecast of distributed solar additions.

Figure III-1: Reference Case NSP System Distributed Solar Forecast



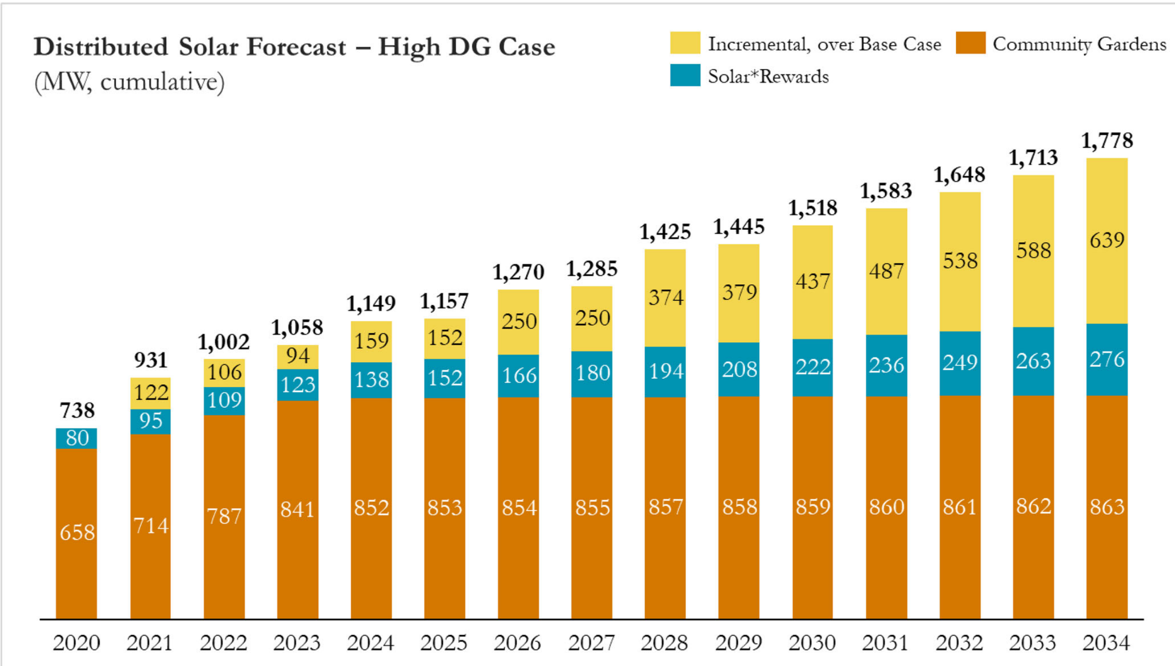
2. *High Distributed Solar Scenario*

In the High adoption scenario, Solar*Rewards and Made in Minnesota are consistent with the Reference Case, for the reasons discussed above. For net metering and CSG in this scenario, however, we assume growth, over and above the Reference Case. This growth is not differentiated by program, as net metering and CSG can generally be thought of as substitutes for each other. For example, we estimate that total solar PV in 2034 is approximately 1,780 MW – of which, approximately 640 MW may be either net metering or CSG.

To develop the High Distributed Solar adoption scenario, we forecasted potential adoption using a Payback adoption model that assumes a 10 percent reduction to the solar installation cost curve, relative to the base case, starting in 2020. The Payback model results indicates a High adoption case forecast of around 1,778 MW of total installed distributed solar by 2034.

We provide the High Distributed Solar scenario forecast below.

Figure III-2: High Distributed Solar Adoption Scenario Forecast



B. Distributed Wind

The NSP System presently has little distributed wind; there are a total of 68 projects that comprise 16 MW, with an additional eight projects in the queue comprising less than 1 MW total. We believe solar PV and distributed storage adoption will account for most of our future DER growth – as both have developed rapidly and are easier for most customers to adopt – and that distributed wind will continue to be a very small proportion of DER on our distribution system. Additionally, there is little information available in the industry regarding the adoption of distributed wind. For these reasons, we have not factored distributed wind installation projections into our Resource Plan forecasts.

C. Distributed Energy Storage

From January 2017 through December 2019 we received 79 interconnection applications to connect distributed energy storage to our Minnesota electric distribution system. Of these 79 storage system applications, 47 are complete and in operation. The current total behind the meter battery storage installed on our Minnesota distribution system is approximately 0.77 MW. We provide an annual breakdown of storage applications received and completed below:

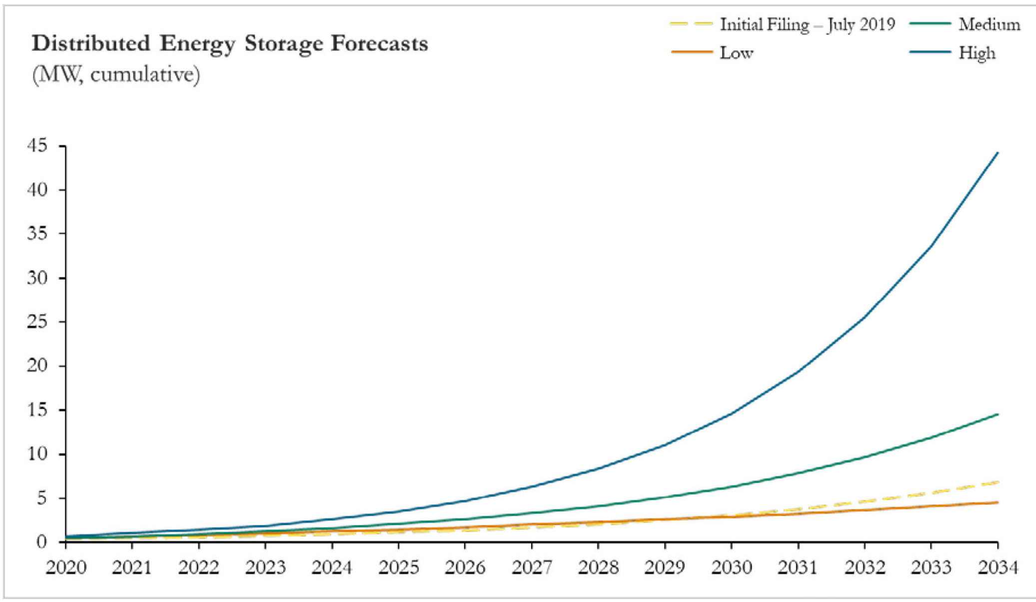
Table III-1: Storage Applications through December 2019 – NSPM, State of Minnesota

Application Year	Total Projects	Number of Projects Completed by Year			Total MW Completed	Projects In Queue
		2017	2018	2019		
2017	18	6	11	0	0.09	1
2018	25	---	12	10	0.39	3
2019	36	---	---	8	0.29	28
Total	**79**	**6**	**23**	**18**	**0.77**	**32**

In order to forecast distributed storage for our system, we utilize our system's current adoption numbers in conjunction with available data from industry consulting firms that specialize in tracking current market conditions and forecasting trends. We have found that the availability of detailed market information on distributed energy storage is limited for the state of Minnesota. Wood Mackenzie, however, currently publishes a quarterly report (U.S. Energy Storage Monitor) which provides high-level trends and forecasts that can be utilized to extrapolate a possible scenario for distributed energy storage within the Company's Minnesota electric distribution system. The Scenarios discussed below are consistent with those used in our 2019 IDP through 2029, and further extrapolated for 2030-2034 using consistent year over year growth rates.

For Scenario 1 entitled "High," we utilized the actual completed energy storage units for NSP Minnesota in years 2017 and 2018 and then applied the forecasted forward growth rates as provided by Wood Mackenzie's most recent forecast for behind the meter storage additions. For Scenario 2, entitled "Mid," we utilized a growth rate forecast from Navigant Research's Global DER Overview that estimates a growth rate of 21.9 percent for distributed energy storage systems. The model extrapolates the current number of installations on the NSP Minnesota system at the Navigant projected rate of growth. We used one additional modeling technique to develop Scenario 3 entitled "Low," which uses a time series analysis of the historical average rate of internal applications received for energy storage systems, as tracked by NSP Minnesota. This alternate scenario models the average number of applications received per month during 2017 and 2018 and then extrapolates a continued growth rate of monthly applications received through 2029, in alignment with the IDP planning period. As in the Reference scenario, we assume a continued growth trend beyond 2029.

Figure III-3: Distributed Energy Storage Systems Growth Forecast



Utilizing all scenarios in conjunction with an estimated average MW for each respective unit deployed, the total cumulative MW of distributed energy storage is not expected to exceed 12 MW by 2029. Even in the most aggressive scenario, with rapid growth, total installed capacity remains under 50 MW by 2034.

That said, distributed energy storage within Minnesota is a nascent market. As such, we note that the various scenarios we have developed are sensitive to exogenous factors such as policy changes, technology advancements and learning curves, and geopolitical risks that could affect raw material availability.

D. Electric Vehicles

With the increase of available models EV market adoption has increased in the U.S. to approximately 1.3 million as of December 2019. At the same point there were approximately 12,000 EVs in the state of Minnesota, and the number continues to increase. As noted above, we include energy demand from Base EV adoption in our corporate forecasts; however, we have also tested a High Adoption sensitivity forecast. The methodologies behind these forecasts are discussed further below.

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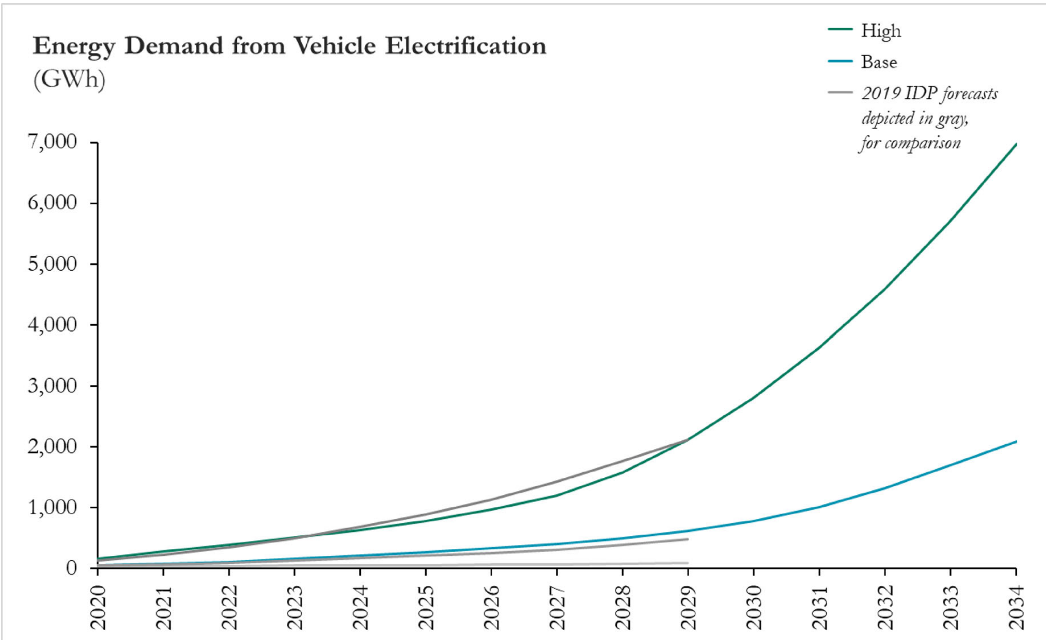
Figure III-4: Electrification Scenarios used in the Supplement Resource Plan Analysis



1. *Base EV Adoption*

Our Base EV forecasts estimate EV adoption using two modeling techniques: 1) Bass Technology Diffusion, and 2) Econometric models. Bass Diffusion models are used to describe technology adoptions patterns in an existing market through an "S" shaped diffusion characteristic. Econometric models use simple payback analysis to estimate potential adoption, incorporating factors such as battery prices, tax incentives, fuel savings and others. After establishing forecasts through both methods, we average the results to estimate base EV adoption in our service area. This results in a cumulative base case adoption estimate of approximately 15 percent of all registered cars and light trucks by 2034. Below we describe both forecasting methods in more detail.

- *Bass Diffusion Modeling.* The Bass Diffusion model approach is now calibrated using state-specific historical EV sales, as well as data through December 2018. The high and low scenarios for the Bass Diffusion models are created using data from states that reflect high historical adoption rates for the high scenario, and low historical adoption rates for the low scenario.

- *Econometric Modeling*. For the econometric modeling approach, we create high and low adoption scenarios that were developed around the base scenario, and that primarily differ in their assumptions on battery and gasoline pricing. Other variables impacting adoption are available tax incentives, and fuel savings. We rely on variation in battery pricing because analysis indicates battery costs are the primary factor for higher EV prices. The high adoption scenario assumes the battery prices are 20 percent lower than the medium scenario, and gasoline prices are higher by one standard deviation. Conversely, the low adoption scenario assumes battery prices are 20 percent higher than the medium scenario, and gasoline prices lower by one standard deviation.

Additionally, we have incorporated into both the Bass diffusion and econometric models a factor for the percentage of vehicles in urban and rural areas. Presently higher adoption is occurring in urban areas with the rural areas anticipated to ramp up slowly.

We believe the forecasting approach we took for this Supplement represents an improvement relative to our previous methodologies and works to bring in line the forecasts used across our most recent IDP and this Supplement. For example, where previously the IDP forecast significantly more adoption than the Resource Plan's Base Case, these forecasts are now generally consistent through the IDP forecast period, as depicted in the figure above. Our estimates show significant volatility between various scenarios, however. The estimates are also sensitive to several exogenous variables – similar to those discussed in the Distributed Energy Storage section above – because battery market dynamics are a significant factor in the cost of EVs. These may include policy, technology, manufacturing supply chain, and geopolitical factors, among others. We have also proposed several customer programs in our Minnesota service area to address increasing customer appetite for transportation electrification solutions, and we engage stakeholder input through an advisory group for these pilots and programs.

Since we are in the early stages of EV adoption, we expect our future estimates will be increasingly robust as we continue to update our models, when new data becomes available. As a result of the nascent market and significant uncertainties, there is a broad range of possible outcomes. We would expect as the market continues to grow, our future forecasts will reflect methodology and input developments that will cause these outlooks to change in the future.

2. *High Electrification Sensitivity*

Consistent with our initial Resource Plan, the High Electrification Scenario included here represents a load forecast sensitivity derived from the E3 statewide decarbonization analysis using PATHWAYS. [25] The objective of this sensitivity was to create a "high bookend," examining the possible impacts on load growth and peak demand growth on our system under a scenario with a level of electrification that would achieve Minnesota's economy-wide goal of an 80 percent reduction in greenhouse gas (GHG) emissions below 2005 levels by 2050.[26] This forecast represents a much higher level of EV adoption than our Base Case, but also includes other beneficial electrification measures. We provide more detailed information regarding the E3 High Electrification sensitivity in Appendix F4 of our initial filing.

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[25] In summary, for the PATHWAYS study, E3 developed a set of long-term economy-wide, deep decarbonization scenarios for the state of Minnesota. These scenarios provide an exploration of the cross-sectoral implications of meeting economy-wide carbon reduction goals, and highlight the role of Xcel Energy, and the electric sector as a whole, in meeting the state's economy-wide carbon goal. For details, see the E3 Minnesota PATHWAYS Report as Appendix P3 to our Initial Filing.

[26] Per Minn. Stat. 216H.02, Subd. 1. *See* https://www.pca.state.mn.us/air/state-and-regional-initiatives

IV. MODELING ASSUMPTIONS AND INPUTS

Since filing our initial Resource Plan in July 2019, the Company has made several changes to its modeling approaches, inputs, and assumptions. Some of these changes in modeling approaches implemented based on discussions with the Department of Commerce (DOC or Department), and feedback from the Commission and stakeholders. Others reflect the passage of time and availability of more recent input and assumptions source material. While a more complete set of updated Strategist and EnCompass modeling assumptions is included in this section, we provide a summary of major changes below.

Topic	Assumption	Change from Initial Filing	Rationale for Change	Sensitivity Performed?
Modeling constraints				
Carbon emissions constraint	▪ No constraint; baseload scenarios may not meet 80 percent reduction goal	▪ Removed modeling constraint of 80 percent carbon reduction by 2030	▪ Alignment with DOC preferred approach	▪ None
"No Going Back" wind replacement capacity	▪ No assumption that existing wind will be replaced when plants or contracts reach end of life	▪ Removed wind replacement capacity from baseline modeling	▪ Alignment with DOC preferred approach	▪ None
Reliability Requirement	▪ Modeling does not include 5.7 GW firm, dispatchable capacity floor; model optimizes resources to develop expansion plans	▪ Removed reliability requirement from baseline modeling	▪ EnCompass modeling better accounts for reliability in hourly chronological modeling ▪ Alignment with DOC preferred approach	▪ None

Topic	Assumption	Change from Initial Filing	Rationale for Change	Sensitivity Performed?
Near term wind availability constraint	▪ No generic wind option made available for model to select before 2026	▪ Generic wind available to select in modeling for each year	▪ Transmission constraints in near term are highly cost prohibitive, such that most greenfield projects are withdrawing from the interconnection queue	▪ Tested alternate sensitivity where wind is available in 2023
Market sales limit	▪ Limits market sales to 25 percent of retail load in EnCompass modeling	▪ Not applicable; no market sales limit capability in Strategist	▪ Limit sales risk exposure	▪ Tested alternate scenarios with unlimited market
Market and technology assumptions				
Market hourly price shaping	▪ Shaped hourly market prices based on retail load	▪ Hourly market price shaped based on thermal load	▪ Alignment with DOC preferred approach	▪ None
Fuel price forecasts	▪ Updated to Fall 2019 forecast vintage	▪ Changed from vintage available prior to previous filing	▪ Previous inputs outdated	▪ High and low fuel price forecasts
Technology price forecasts for wind, solar, and storage	▪ Used National Renewable Energy Labs (NREL) *Annual Technology Baseline (ATB) 2019* assumptions	▪ Updated from 2018 ATB to 2019 ATB for wind and solar ▪ Shifted from using internal price assumptions to 2019 ATB for storage	▪ Previous inputs outdated	▪ Used High and low technology price forecasts in sensitivities

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Topic	Assumption	Change from Initial Filing	Rationale for Change	Sensitivity Performed?
Wind resource production	▪ Used 2019 NREL ATB price inputs for Technology Resource Group (TRG) 2	▪ Previously used 2018 ATB price assumptions for TRG 1, which reflected a higher capacity factor expectation	▪ We believe TRG 2 capacity factors better align with wind resource quality for remaining sites in our region	▪ None
Solar resource production	▪ Assumed 22 percent capacity factor in first year, with 0.5 percent per year degradation	▪ Previously assumed 17.7 percent levelized capacity factor	▪ Better alignment with performance of our existing solar resources	▪ None
Renewable transmission interconnect cost	▪ Wind: $500/kW ▪ Solar: $200/kW	▪ Wind: Increased from $400/kW for greenfield wind ▪ Solar: Increased from $140/kW	▪ MISO transmission constraints create upward pressure on interconnection costs	▪ None
Solar capacity accreditation	▪ 50 percent ELCC to 2023, declining to 30 percent in 2033 at a rate of 2 percent per year	▪ 50 percent ELCC for the full analysis period	▪ Aligns with assumptions used in MISO MTEP 2019 modeling	▪ Performed alternate scenario with 50 percent ELCC held constant

Topic	Assumption	Change from Initial Filing	Rationale for Change	Sensitivity Performed?
Wind capacity accreditation	▪ 16.7 percent ELCC throughout the planning period	▪ 15.6 percent ELCC throughout the planning period	▪ Updated to reflect MISO Zone 1 ELCC rather than MISO-wide assumptions ▪ Updated to match MISO's most recent Wind and Solar Capacity Credit report.	▪ None
Effective Reserve Margin	▪ Reserve margin updated to 3.46 percent, based on latest MISO LOLE Study (2020-2021)	▪ 2.98 percent effective reserve margin	▪ Updated to most recent LOLE study result	▪ None
Upper Midwest System Assumptions				
Unit retirement dates	▪ All existing unit retirement years with end of financial life	▪ Selected units used differing retirement dates for resource planning purposes	▪ Conforms with Commission direction	▪ None
Seasonal coal dispatch	▪ King and Sherco 2 do not dispatch from March-May and September-November, through 2023	▪ No units were modeled with seasonal dispatch	▪ Reflects Commission-approved operational practices	▪ None
Load forecasts	▪ Updated to fall 2019 internal forecast vintage	▪ Changed from fall 2018 internal forecast	▪ Previous inputs outdated	▪ None

Topic	Assumption	Change from Initial Filing	Rationale for Change	Sensitivity Performed?
DER forecasts	▪ Updated to latest vintage for each technology	▪ Changed from vintage available prior to previous filing	▪ Previous inputs outdated	▪ Sensitivity on low load/high DER adoption
EV adoption forecasts	▪ Updated to latest vintage, aligned with most recent forecasts used in IDP	▪ Changed from vintage available prior to previous filing	▪ Previous inputs outdated ▪ Conforms with Commission direction to better align forecasts across filings	▪ Sensitivity on high EV adoption
Nuclear budgets	▪ Updated to most recent vintage for Nuclear Decommissioning Trust, Operations and Maintenance and Capital Expenditure budgets	▪ Changed from vintage available prior to previous filing	▪ Previous inputs outdated	▪ None

A. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.47 percent. The rates shown below were calculated by taking a weighted average of each NSP jurisdiction's last allowed/settled electric retail rate case.

Table IV-1: Discount Rate and Capital Structure

Discount Rate and Capital Structure				
	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	45.72%	4.79%	2.19%	1.58%
Common Equity	52.39%	9.25%	4.85%	4.85%
Short-Term Debt	1.89%	3.55%	0.07%	0.05%
Total			**7.10%**	**6.47%**

B. Inflation Rates

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling and are developed using long-term forecasts from Global Insight. The general inflation rate of 2 percent is from their long-term forecast for "Chained Price Index for Total Personal Consumption Expenditures" published in the second quarter of 2018.

C. Reserve Margin

The reserve margin at the time of MISO's peak is 8.9 percent from the 2020-2021 LOLE Study Report, published November 2019. The coincidence factor between the NSP System and MISO system peak is 95 percent. Therefore, the effective reserve margin is:

$$(95\, percent\ coincidence\ factor) x\ (1 + 8.9\, percent) - 1 \\ = \mathbf{3.46}\, percent\ effective\ reserve\ margin\ for\ NSP$$

D. CO_2 Costs

The Present Value of Societal Cost (PVSC) Base Case CO_2 values are based on the high environmental cost values for CO_2 through 2024 (page 31 of the Minnesota Public Utilities Commission's Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.). All prices are converted to 2018 real dollars using the 2017 Gross Domestic Product Implicit Price Deflator (GDPIPD) of 113.416 and then escalated at general inflation thereafter.

The PVSC Base Case values starting in 2025 are based on the "high" end of the range of regulated costs (see page 12 of MPUC Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs in Dockets No. E999/CI-07-1199 and E999/DI-17-53 issued June 11, 2018). All prices escalate at general inflation.

The Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs requires four alternative scenarios to be run in addition to the PVSC Base Case. The Order Extending Deadline for Filing Next Resource Plan issued January 30, 2019 also requires a scenario using the midpoint of the Commission's most recently approved externalities and regulatory costs of carbon. The values in the PVSC Base Case and alternative scenarios are set out below.

Table IV-2: CO_2 Costs

CO2 Costs ($ per short ton)						
Year	Low Environmental Cost	High Environmental Cost	Low Environmental/ Regulatory Costs	Mid Environmental/ Regulatory Costs	PVSC - High Environmental/ Regulatory Costs	PVRR - Omitting CO2 Cost Considerations
2018	$9.09	$42.76	$9.09	$25.92	$42.76	$0.00
2019	$9.49	$44.58	$9.49	$27.04	$44.58	$0.00
2020	$9.90	$46.45	$9.90	$28.18	$46.45	$0.00
2021	$10.32	$48.39	$10.32	$29.35	$48.39	$0.00
2022	$10.77	$50.38	$10.77	$30.57	$50.38	$0.00
2023	$11.22	$52.43	$11.22	$31.82	$52.43	$0.00
2024	$11.69	$54.55	$11.69	$33.12	$54.55	$0.00
2025	$12.16	$56.72	$5.00	$15.00	$25.00	$0.00
2026	$12.67	$58.97	$5.10	$15.30	$25.50	$0.00
2027	$13.17	$61.29	$5.20	$15.61	$26.01	$0.00
2028	$13.70	$63.67	$5.31	$15.92	$26.53	$0.00
2029	$14.24	$66.12	$5.41	$16.24	$27.06	$0.00
2030	$14.80	$68.64	$5.52	$16.56	$27.60	$0.00
2031	$15.37	$71.24	$5.63	$16.89	$28.15	$0.00
2032	$15.97	$73.91	$5.74	$17.23	$28.72	$0.00
2033	$16.57	$76.67	$5.86	$17.57	$29.29	$0.00
2034	$17.21	$79.50	$5.98	$17.93	$29.88	$0.00
2035	$17.85	$82.41	$6.09	$18.28	$30.47	$0.00
2036	$18.52	$85.41	$6.22	$18.65	$31.08	$0.00
2037	$19.20	$88.50	$6.34	$19.02	$31.71	$0.00
2038	$19.91	$91.68	$6.47	$19.40	$32.34	$0.00
2039	$20.62	$94.96	$6.60	$19.79	$32.99	$0.00
2040	$21.38	$98.32	$6.73	$20.19	$33.65	$0.00
2041	$22.14	$101.78	$6.86	$20.59	$34.32	$0.00
2042	$22.94	$105.34	$7.00	$21.00	$35.01	$0.00
2043	$23.74	$109.00	$7.14	$21.42	$35.71	$0.00
2044	$24.58	$112.76	$7.28	$21.85	$36.42	$0.00
2045	$25.43	$116.63	$7.43	$22.29	$37.15	$0.00
2046	$26.33	$120.61	$7.58	$22.73	$37.89	$0.00
2047	$27.23	$124.71	$7.73	$23.19	$38.65	$0.00
2048	$28.17	$128.92	$7.88	$23.65	$39.42	$0.00
2049	$29.12	$133.24	$8.04	$24.13	$40.21	$0.00
2050	$30.12	$137.69	$8.20	$24.61	$41.02	$0.00
2051	$31.14	$142.26	$8.37	$25.10	$41.84	$0.00
2052	$32.18	$146.97	$8.53	$25.60	$42.67	$0.00
2053	$33.26	$151.80	$8.71	$26.12	$43.53	$0.00
2054	$34.36	$156.76	$8.88	$26.64	$44.40	$0.00
2055	$35.50	$161.87	$9.06	$27.17	$45.28	$0.00
2056	$36.66	$167.11	$9.24	$27.71	$46.19	$0.00
2057	$37.86	$172.51	$9.42	$28.27	$47.11	$0.00

E. All Other Externality Costs

The values of the criteria pollutants are derived from the high and low values for each of the three locations, as determined in the Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018. The midpoint externality costs are the average of the low and high values. All prices are escalated to 2018 real dollars using the 2017 GDPIPD of 113.416. The high, low and midpoint externality costs will be used in the CO_2 sensitivities as described above.

Table IV-3: Externality Costs

MPUC Low Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$6,116	$4,829	$3,643	$0
NOx	$2,934	$2,622	$2,110	$28
PM2.5	$10,697	$6,856	$3,654	$872
CO	$1.65	$1.17	$0.31	$0.31
Pb	$4,857	$2,562	$624	$624

MPUC High Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$15,288	$12,030	$8,878	$0
NOx	$8,390	$7,798	$6,771	$158
PM2.5	$26,721	$17,091	$8,973	$1,327
CO	$3.51	$2.08	$0.63	$0.63
Pb	$6,011	$3,094	$695	$695

MPUC Midpoint Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$10,702	$8,430	$6,261	$0
NOx	$5,662	$5,210	$4,441	$93
PM2.5	$18,709	$11,974	$6,313	$1,099
CO	$2.58	$1.63	$0.47	$0.47
Pb	$5,434	$2,828	$659	$659

F. Demand and Energy Forecast

The Company's fall 2019 load forecast is used as the base assumption and assumes that EV impacts growth continues throughout the forecast period. The energy efficiency (EE) forecast included in the base forecast developed by the Company's Load Forecasting department assumes somewhat less energy efficiency (EE) savings levels than those included in our initial Resource Plan's Preferred Plan. Please see Attachment A Section II for more information.

The "Load Forecast with EE" shown in Table IV-4 below is the starting point for the load inputs. In all modeling scenarios, the "EE" is removed – the removal of these EE program effects, which have a 14-year life, impacts the load forecast through 2048. In the initial filing, the three EE Bundles (discussed below) were optimized as Proview Alternatives. For this supplemental filing, the first two EE Bundles are included in all scenarios. The resulting forecast, before the optimized EE bundles are added, is shown below in Table IV-4 as "Forecast Without EE." The forecasts shown do not include the impact of DG solar, as DG solar is modeled as a resource, not a load modifier.

Table IV-4: Demand and Energy Forecast

Demand and Energy Forecast				
	Demand (MW)		Energy (GWh)	
Year	Forecast with EE	Forecast without EE	Forecast with EE	Forecast without EE
2018	9,152	9,152	43,914	43,914
2019	9,084	9,084	43,558	43,558
2020	9,099	9,230	43,170	43,806
2021	9,079	9,312	42,741	44,018
2022	9,126	9,462	42,628	44,549
2023	9,165	9,604	42,440	45,004
2024	9,184	9,728	42,339	45,555
2025	9,238	9,849	42,324	45,976
2026	9,311	9,992	42,470	46,565
2027	9,414	10,164	42,757	47,296
2028	9,504	10,327	43,221	48,216
2029	9,525	10,416	43,006	48,432
2030	9,605	10,566	43,224	49,093
2031	9,679	10,710	43,420	49,734
2032	9,775	10,880	43,903	50,678
2033	9,979	11,058	44,532	51,299
2034	10,190	11,246	45,426	52,203
2035	10,343	11,269	46,158	52,299
2036	10,502	11,325	47,028	52,527
2037	10,673	11,393	47,647	52,503
2038	10,803	11,420	48,209	52,422
2039	10,936	11,449	48,833	52,394
2040	11,073	11,518	49,603	52,729
2041	11,209	11,585	50,055	52,737
2042	11,338	11,645	50,635	52,873
2043	11,467	11,701	51,267	53,048
2044	11,614	11,780	52,023	53,374
2045	11,722	11,818	52,468	53,375
2046	11,839	11,865	53,010	53,473
2047	11,951	11,903	53,545	53,547
2048	12,021	11,998	54,150	54,160
2049	12,045	12,045	54,202	54,202
2050	12,097	12,097	54,407	54,407
2051	12,149	12,149	54,611	54,611
2052	12,199	12,199	54,947	54,947
2053	12,252	12,252	55,022	55,022
2054	12,305	12,305	55,226	55,226
2055	12,357	12,357	55,431	55,431
2056	12,409	12,409	55,765	55,765
2057	12,461	12,461	55,840	55,840

The low load sensitivity includes high customer-adoption-based DG/DER growth and higher EE savings, which reduces load. The high load sensitivity includes high electrification load. These assumptions are shown in Table IV-5 and Table IV-6 and are incremental/decremental to the forecast shown in Table IV-4.

Table IV-5: High Load Sensitivity

High Electrification		
Year	Energy (GWh)	Demand (MW)
2018	35	8
2019	46	6
2020	59	7
2021	166	20
2022	276	33
2023	390	47
2024	507	62
2025	592	65
2026	692	77
2027	812	85
2028	939	98
2029	1,202	118
2030	1,578	162
2031	2,028	205
2032	2,538	251
2033	3,137	305
2034	3,857	367
2035	4,716	438
2036	5,657	515
2037	6,672	596
2038	7,741	679
2039	8,851	766
2040	9,996	854
2041	11,114	940
2042	12,199	1,025
2043	13,241	1,118
2044	14,229	1,796
2045	15,159	2,520
2046	16,037	3,173
2047	16,877	3,796
2048	17,696	4,647
2049	18,660	4,908
2050	19,530	5,407
2051	20,634	5,947
2052	21,645	6,418
2053	22,656	6,896
2054	23,666	7,384
2055	24,677	7,877
2056	25,688	8,352
2057	26,699	8,840

**Demand values are coincident to system peak*

Table IV- 6: Low Load Sensitivity

High DER Growth		
Year	Energy (GWh)	Demand (Nameplate MW)
2018	0	0
2019	0	0
2020	0	0
2021	207	122
2022	180	106
2023	159	94
2024	270	159
2025	258	152
2026	423	250
2027	423	250
2028	635	374
2029	641	379
2030	740	437
2031	826	487
2032	913	538
2033	996	588
2034	1,082	639
2035	1,167	689
2036	1,256	739
2037	1,338	790
2038	1,423	840
2039	1,509	891
2040	1,598	941
2041	1,631	963
2042	1,580	933
2043	1,529	903
2044	1,482	872
2045	1,425	842
2046	1,350	797
2047	1,296	765
2048	1,245	733
2049	1,187	701
2050	1,131	668
2051	1,063	628
2052	1,009	594
2053	932	550
2054	872	515
2055	807	476
2056	742	437
2057	671	396

G. Energy Efficiency Bundles

The EE "Program" and "Maximum" Bundles are based on the Minnesota DOC's Minnesota Energy Efficiency Potential Study: 2020-2029 published December 4, 2018. The "Optimal" Bundle was developed by the Company. The bundles are decremental (reducing energy and demand) to the "Forecast without EE" shown in Table IV-4.

Table IV- 7: Energy Efficiency Bundles

	Energy(MWh)			Demand (MW)			Costs ($000)		
Year	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0
2020	621	43	231	97	18	36	100,989	12,598	148,331
2021	1,326	91	493	207	38	77	113,525	13,905	167,221
2022	1,913	148	702	301	60	113	121,239	21,425	177,197
2023	2,555	211	928	407	86	154	133,614	23,931	196,474
2024	3,094	279	1,110	520	116	197	148,406	26,120	217,388
2025	3,629	346	1,289	635	146	241	152,433	26,077	223,293
2026	4,330	414	1,533	759	176	289	160,445	26,236	233,779
2027	5,054	482	1,785	886	206	338	167,718	26,637	242,963
2028	5,785	551	2,040	1,012	235	387	174,161	27,018	249,373
2029	6,454	606	2,280	1,127	259	432	162,170	23,442	233,114
2030	7,110	659	2,516	1,241	283	477	162,170	23,442	233,114
2031	7,753	710	2,748	1,354	307	522	162,170	23,442	233,114
2032	8,339	760	2,960	1,460	329	564	162,170	23,442	233,114
2033	8,909	808	3,168	1,564	352	605	162,170	23,442	233,114
2034	9,464	857	3,370	1,667	374	646	162,170	23,442	233,114
2035	9,250	846	3,294	1,648	370	638	0	0	0
2036	8,739	835	3,073	1,579	366	600	0	0	0
2037	8,088	789	2,829	1,470	347	557	0	0	0
2038	7,450	741	2,590	1,369	327	517	0	0	0
2039	6,841	685	2,372	1,267	304	475	0	0	0
2040	6,197	626	2,144	1,154	278	430	0	0	0
2041	5,543	562	1,919	1,036	250	384	0	0	0
2042	4,871	499	1,685	916	221	337	0	0	0
2043	4,220	434	1,457	796	191	291	0	0	0
2044	3,561	377	1,218	678	165	245	0	0	0
2045	2,912	318	990	562	139	201	0	0	0
2046	2,276	265	761	451	116	156	0	0	0
2047	1,746	212	573	349	93	117	0	0	0
2048	1,216	159	384	248	70	79	0	0	0
2049	686	106	195	146	46	40	0	0	0
2050	156	53	7	45	23	1	0	0	0
2051	0	0	0	0	0	0	0	0	0
2052	0	0	0	0	0	0	0	0	0
2053	0	0	0	0	0	0	0	0	0
2054	0	0	0	0	0	0	0	0	0
2055	0	0	0	0	0	0	0	0	0
2056	0	0	0	0	0	0	0	0	0
2057	0	0	0	0	0	0	0	0	0

***Demand values are coincident to system peak*

H. Demand Response Forecast

The base demand response forecast was developed by the Company and is included in all scenarios and sensitivities. The three demand response "Bundles" are from the Brattle Potential Study provided as Appendix G2. The Bundles are incremental to the base demand response forecast. In the initial filing, the three DR Bundles were optimized as Proview Alternatives. For this Supplement, the first DR Bundle is included in all scenarios.

Table IV-8: Demand Response Forecast

Demand (MW) Adjusted For Reserve Margin					Costs ($000)		
Year	Base Demand Response Forecast	Bundle 1	Bundle 2	Bundle 3	Bundle 1	Bundle 2	Bundle 3
2018	852	0	0	0	0	0	0
2019	928	0	0	0	0	0	0
2020	1012	33	107	90	1,752	7,659	11,311
2021	1027	165	112	98	8,917	8,150	12,587
2022	1041	232	117	107	12,748	8,676	14,016
2023	1055	294	121	110	16,489	9,137	14,758
2024	1066	341	133	101	19,512	10,277	13,829
2025	1072	382	145	92	22,305	11,459	12,858
2026	1077	394	152	93	23,475	12,207	13,326
2027	1078	407	159	95	24,786	13,080	13,845
2028	1077	423	168	97	26,245	14,086	14,418
2029	1071	440	178	99	27,859	15,231	15,047
2030	1059	458	190	102	29,637	16,522	15,734
2031	1048	478	202	104	31,551	17,926	16,467
2032	1037	499	215	107	33,612	19,451	17,251
2033	1026	521	228	110	35,832	21,109	18,088
2034	1016	545	243	113	38,224	22,911	18,984
2035	1005	570	259	116	40,802	24,870	19,943
2036	995	596	275	120	43,582	26,999	20,971
2037	985	624	293	123	46,580	29,313	22,072
2038	976	654	312	127	49,814	31,829	23,253
2039	966	686	332	132	53,305	34,564	24,522
2040	957	720	353	136	57,073	37,537	25,884
2041	948	720	353	136	58,215	38,288	26,402
2042	939	720	353	136	59,379	39,054	26,930
2043	930	720	353	136	60,566	39,835	27,468
2044	922	720	353	136	61,778	40,632	28,018
2045	914	720	353	136	63,013	41,444	28,578
2046	906	720	353	136	64,274	42,273	29,150
2047	898	720	353	136	65,559	43,118	29,733
2048	890	720	353	136	66,870	43,981	30,327
2049	882	720	353	136	68,208	44,860	30,934
2050	875	720	353	136	69,572	45,758	31,552
2051	868	720	353	136	70,963	46,673	32,183
2052	860	720	353	136	72,382	47,606	32,827
2053	853	720	353	136	73,830	48,558	33,484
2054	847	720	353	136	75,307	49,530	34,153
2055	840	720	353	136	76,813	50,520	34,836
2056	833	720	353	136	78,349	51,531	35,533
2057	827	720	353	136	79,916	52,561	36,244

**Demand values are coincident to system peak.*

I. Fuel Price Forecasts

Natural gas price forecasts are developed using a blend of market information (New York Mercantile Exchange, or NYMEX, futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA) and Petroleum Industry Research Associates (PIRA).

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices to cover non-contracted coal needs. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five-year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Added to the spot coal forecast, which is just for the coal commodity, are: transportation charges, SO_2 costs, freeze control and dust suppressant, as required.

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA using a similar methodology as is used for the gas price forecast. Table IV-9 below shows the market prices under zero CO_2 cost assumptions. The market purchases and sales limit for transaction volume between the Company and MISO is 1,350 MWh/h in 2018, 1,800 MWh/h from 2019-2022, and 2,300 MWh/h for 2023 and beyond.

High and low-price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base forecast starting when the long-term fundamentally-based forecasts are blended with market information (NYMEX futures prices).

Table IV-9: Fuel and Market Price Forecasts

	Base Price Forecast				Low Price Forecast				High Price Forecast			
	Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)	
Year	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak
2018	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61
2019	$2.08	$2.60	$26.93	$20.98	$2.08	$2.60	$26.93	$20.98	$2.08	$2.60	$26.93	$20.98
2020	$2.11	$2.26	$25.78	$20.13	$2.11	$2.26	$25.78	$20.13	$2.11	$2.26	$25.78	$20.13
2021	$2.14	$2.23	$25.32	$19.06	$2.14	$2.23	$25.32	$19.06	$2.14	$2.23	$25.32	$19.06
2022	$2.19	$2.33	$26.92	$20.45	$2.17	$2.28	$26.33	$20.00	$2.24	$2.38	$27.52	$20.90
2023	$2.25	$2.45	$29.31	$22.19	$2.19	$2.34	$27.96	$21.17	$2.36	$2.57	$30.68	$23.23
2024	$2.30	$2.58	$30.00	$23.20	$2.22	$2.40	$27.94	$21.60	$2.46	$2.76	$32.16	$24.87
2025	$2.35	$2.79	$31.47	$24.36	$2.24	$2.50	$28.17	$21.80	$2.57	$3.11	$35.04	$27.12
2026	$2.40	$2.98	$32.30	$24.99	$2.27	$2.58	$28.01	$21.67	$2.69	$3.42	$37.09	$28.70
2027	$2.45	$3.12	$33.35	$26.71	$2.29	$2.64	$28.28	$22.64	$2.81	$3.66	$39.16	$31.36
2028	$2.51	$3.26	$34.09	$26.97	$2.32	$2.71	$28.25	$22.35	$2.93	$3.92	$40.92	$32.38
2029	$2.57	$3.44	$35.21	$28.25	$2.34	$2.78	$28.42	$22.79	$3.07	$4.24	$43.38	$34.80
2030	$2.62	$3.70	$38.27	$30.69	$2.37	$2.88	$29.83	$23.92	$3.20	$4.71	$48.76	$39.09
2031	$2.68	$3.87	$39.33	$32.07	$2.40	$2.95	$29.97	$24.44	$3.35	$5.04	$51.22	$41.77
2032	$2.75	$4.02	$39.75	$33.14	$2.43	$3.01	$29.71	$24.77	$3.51	$5.34	$52.76	$43.99
2033	$2.81	$4.10	$39.93	$33.46	$2.45	$3.03	$29.58	$24.79	$3.67	$5.48	$53.47	$44.80
2034	$2.87	$4.20	$41.13	$34.56	$2.48	$3.07	$30.08	$25.28	$3.83	$5.70	$55.76	$46.86
2035	$2.94	$4.35	$42.15	$35.66	$2.51	$3.13	$30.32	$25.65	$4.00	$6.00	$58.12	$49.17
2036	$2.99	$4.47	$42.79	$36.60	$2.53	$3.17	$30.37	$25.97	$4.14	$6.24	$59.80	$51.13
2037	$3.07	$4.65	$44.00	$38.21	$2.56	$3.24	$30.61	$26.58	$4.36	$6.63	$62.69	$54.44
2038	$3.14	$4.86	$44.95	$39.45	$2.60	$3.31	$30.60	$26.85	$4.58	$7.08	$65.43	$57.42
2039	$3.23	$5.04	$45.82	$40.48	$2.63	$3.37	$30.63	$27.06	$4.83	$7.47	$67.88	$59.98
2040	$3.31	$5.22	$46.61	$41.48	$2.66	$3.43	$30.61	$27.25	$5.06	$7.87	$70.25	$62.53
2041	$3.37	$5.32	$46.52	$41.48	$2.69	$3.46	$30.27	$26.99	$5.26	$8.10	$70.79	$63.12
2042	$3.45	$5.47	$47.61	$42.64	$2.72	$3.51	$30.57	$27.38	$5.51	$8.43	$73.40	$65.74
2043	$3.53	$5.62	$48.37	$43.71	$2.75	$3.56	$30.64	$27.69	$5.77	$8.78	$75.56	$68.28
2044	$3.62	$5.78	$49.72	$44.99	$2.79	$3.61	$31.04	$28.09	$6.05	$9.17	$78.79	$71.29
2045	$3.70	$5.99	$51.23	$46.37	$2.82	$3.68	$31.45	$28.46	$6.31	$9.65	$82.57	$74.73
2046	$3.78	$6.17	$52.49	$47.53	$2.85	$3.73	$31.74	$28.74	$6.59	$10.09	$85.85	$77.73
2047	$3.86	$6.29	$53.27	$48.57	$2.88	$3.77	$31.89	$29.08	$6.88	$10.40	$87.98	$80.22
2048	$3.95	$6.46	$54.39	$49.88	$2.91	$3.82	$32.15	$29.49	$7.20	$10.80	$90.96	$83.42
2049	$4.04	$6.66	$55.69	$50.92	$2.95	$3.88	$32.43	$29.65	$7.53	$11.30	$94.52	$86.43
2050	$4.13	$6.77	$56.64	$51.71	$2.98	$3.91	$32.70	$29.85	$7.87	$11.60	$96.97	$88.53
2051	$4.22	$6.96	$58.23	$53.16	$3.01	$3.96	$33.16	$30.27	$8.21	$12.08	$101.05	$92.24
2052	$4.31	$7.13	$59.62	$54.42	$3.04	$4.01	$33.56	$30.63	$8.57	$12.51	$104.64	$95.53
2053	$4.41	$7.29	$61.00	$55.68	$3.08	$4.06	$33.94	$30.99	$8.94	$12.95	$108.29	$98.85
2054	$4.50	$7.46	$62.38	$56.95	$3.11	$4.10	$34.33	$31.34	$9.33	$13.39	$111.97	$102.21
2055	$4.60	$7.62	$63.76	$58.21	$3.14	$4.15	$34.71	$31.69	$9.73	$13.83	$115.69	$105.61
2056	$4.69	$7.79	$65.15	$59.47	$3.17	$4.19	$35.09	$32.03	$10.12	$14.28	$119.45	$109.05
2057	$4.79	$7.95	$66.53	$60.73	$3.21	$4.24	$35.46	$32.37	$10.52	$14.74	$123.26	$112.52

**Coal prices are delivered prices, while gas and market prices are hub prices.*

J. Baseload Retirement "Leave Behind" Costs

Based on the MISO Y2 retirement studies performed on existing coal and nuclear resources, the Company developed transmission reinforcement or "leave behind" estimates, which reflect costs required to mitigate localized grid impacts of the retirement of major baseload resources. The reinforcement costs are included as a one-time charge based on the timing of the resource retirement.

Specifically, we have included the following proxy leave behind costs related to our baseload resource retirements as estimated from the MISO studies. We applied these costs in the modeling as soon as the resource is retired, over a three-year period, to reflect the estimated local transmission reinforcement costs assumed to be required upon retirement. All numbers below are in real dollar terms ($2020).

- King: $48 million
- Sherco 3: $48 million
- Monticello: $96 million
- Prairie Island 1: $96 million
- Prairie Island 2: $96 million

K. Surplus Capacity Credit

The surplus capacity credit of up to 500 MW is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic brownfield H-Class combustion turbine on an economic carrying charge basis.

Table IV-10: Surplus Capacity Credit

Surplus Capacity Credit																				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
$/kw-mo	4.57	4.66	4.75	4.85	4.95	5.05	5.15	5.25	5.35	5.46	5.57	5.68	5.80	5.91	6.03	6.15	6.27	6.40	6.53	6.66
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
$/kw-mo	6.79	6.93	7.07	7.21	7.35	7.50	7.65	7.80	7.96	8.12	8.28	8.44	8.61	8.79	8.96	9.14	9.32	9.51	9.70	9.89

L. Effective Load Carrying Capability Capacity Credit for Wind, Solar, and Battery Resources

The ELCC for existing wind units is based on current MISO accreditation. The ELCC for generic wind is equal to 16.7 percent of their nameplate rating per MISO 2020/2021 Wind Capacity Report. The ELCC for generic solar is based on the values provided in MISO's MTEP 2019 in Appendix E,[27] and is 50 percent of the alternating current (AC) nameplate capacity through 2023, declining 2 percent annually to 30 percent by 2033 where it remains for the rest of the forecast period. The ELCC assigned for a generic 4-hour battery is equal to 100 percent of the AC equivalent capacity. The ELCC used for hybrid options are the same as the individual components.

M. Spinning Reserve Requirement

Spinning reserve is the online reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled is 137 MW and is based on a 12-month rolling average of spinning reserves carried by the NSP System within MISO.

N. Emergency Energy

Emergency energy is used to cover events where there are not enough resources or market purchase energy available to meet system energy requirements. In Strategist, this is set to $500/MWh. Encompass uses the default value of $10,000/MWh. The primary reason for this difference is the way the models utilize this input. In Strategist's dispatch approach, the emergency energy is determined after the dispatch, when all resources have been utilized and an energy shortfall still exists. In EnCompass, emergency energy is a "soft constraint" that allows emergency energy to "dispatch" as a last resort resource, in order for the model to find a feasible solution. The EnCompass price is set to a high level to ensure that all other available resources – including those that may have a very high effective $/MWh cost resulting from startup costs spread over a very small required run time – are utilized before emergency energy.

O. Transmission Delivery Costs and Interconnection Costs

Transmission delivery costs for generic resources were developed by the Company. They are based on evaluation of recent and historical MISO studies and queue results. These costs represent "grid upgrades" to ensure deliverability of energy from these facilities to the overall bulk electric system.

[27] Available at: https://cdn.misoenergy.org//MTEP19%20Appendix%20E-Futures%20Assumptions382958.pdf

We note additionally that interconnection costs for generic resources are included in the capital costs in Table IV-14 in Part U of this section and represent "behind the fence" costs associated with substation and representative gen-tie construction.

Table IV-11: Transmission Delivery Costs

Transmission Delivery Costs				
	CC	CT	Wind	Solar
$/kw	500	200	500	200

P. Integration and Congestion Costs

Integration costs are taken from studies conducted by Enernex and apply to new wind and solar resources only. Congestion costs were not included in the model.

Table IV-12: Integration Costs

Integration Costs ($/MWh)		
Year	Wind	Solar
2018	0.00	0.00
2019	0.00	0.00
2020	0.41	0.41
2021	0.42	0.42
2022	0.43	0.43
2023	0.44	0.44
2024	0.45	0.45
2025	0.46	0.46
2026	0.47	0.47
2027	0.48	0.48
2028	0.49	0.49
2029	0.49	0.49
2030	0.50	0.50
2031	0.51	0.51
2032	0.53	0.53
2033	0.54	0.54
2034	0.55	0.55
2035	0.56	0.56
2036	0.57	0.57
2037	0.58	0.58
2038	0.59	0.59
2039	0.60	0.60
2040	0.62	0.62
2041	0.63	0.63
2042	0.64	0.64
2043	0.65	0.65
2044	0.67	0.67
2045	0.68	0.68
2046	0.69	0.69
2047	0.71	0.71
2048	0.72	0.72
2049	0.74	0.74
2050	0.75	0.75
2051	0.77	0.77
2052	0.78	0.78
2053	0.80	0.80
2054	0.81	0.81
2055	0.83	0.83
2056	0.84	0.84
2057	0.86	0.86

Q. Distributed Solar Generation and Community Solar Gardens

The distributed solar and Community Solar Gardens inputs are based on the most recent Company forecasts. Distributed Solar is modeled assuming a degradation of half a percent annually in generation. Community Solar Gardens are modeled assuming a degradation of half a percent annually in generation, and a twenty-five-year service life. After a "vintage" of additions reach end of life, it is assumed 90% of the capacity is replaced at then-current costs.

Table IV-13: Distributed Solar Forecast

Distributed Solar (Nameplate MW)			
Year	Solar Rewards	Community Gardens	Total
2018	29	246	274
2019	61	504	565
2020	80	658	738
2021	95	714	809
2022	109	787	897
2023	123	841	964
2024	138	852	989
2025	152	853	1,005
2026	166	854	1,020
2027	180	855	1,035
2028	194	857	1,050
2029	208	858	1,066
2030	222	859	1,080
2031	236	860	1,095
2032	249	861	1,110
2033	263	862	1,125
2034	276	863	1,140
2035	290	864	1,154
2036	303	866	1,169
2037	317	867	1,184
2038	330	868	1,198
2039	343	869	1,212
2040	357	870	1,227
2041	370	871	1,241
2042	383	869	1,252
2043	396	852	1,247
2044	409	830	1,239
2045	421	818	1,239
2046	434	814	1,248
2047	447	808	1,255
2048	460	805	1,264
2049	472	805	1,277
2050	491	806	1,297
2051	504	807	1,311
2052	518	808	1,326
2053	531	809	1,340
2054	545	810	1,355
2055	559	811	1,369
2056	572	812	1,384
2057	586	812	1,398

R. Owned Unit Modeled Operating Characteristics and Costs

Company-owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each company owned resource.

a. Retirement Date
b. Maximum Capacity
c. Current Unforced Capacity (UCAP) Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and particulate matter (PM)
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

S. Thermal PPA Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of typical operating and cost inputs for each thermal PPA.

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

T. Renewable Energy (PPAs and Owned) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each renewable energy unit.

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Wind and solar hourly patterns are developed through a "Typical Meteorological Year" process where individual months are selected from the years 2017-2020 to develop a representative typical year. Actual generation data from the selected months is used to develop the profile for each unit. For units where generation data is not complete or not available, data from a nearby similar unit is used.

U. Generic Assumptions

Generic resources are modeled based upon their expected operating characteristics and projected costs. Generic thermal costs are developed by the Company. Generic renewable and battery costs are based on data from the NREL 2019 ATB. Utility-scale wind and solar costs shown in Tables IV-18 through IV-20 include transmission costs from Table IV-11 while DG/distributed solar does not.

The modeling no longer assumes "no going back" on renewables, which was the replacement of renewable resources for a similar resource when they reached the end of their life, but rather allows all renewable additions to be optimized.

In addition to base cost data for renewables, low and high costs are used for various sensitivities. Low and high wind, solar, and battery costs are also based on the 2019 ATB data. Below is a list of typical operating and cost inputs for each generic resource.

Thermal

a. Retirement Date
b. Maximum Capacity
c. UCAP Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

Renewable

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Table IV-14: Thermal Generic Information (Costs in 2018 Dollars)

Thermal Generic Information					
Resource	**Sherco CC**	**Generic CC**	**Generic CT**	**Generic CT**	**Generic CT**
Technology	7H	7H	7H	7F	7H
Location Type	Brownfield	Greenfield	Brownfield	Brownfield	Greenfield
Cooling Type	Wet	Dry	Dry	Dry	Dry
Book life	40	40	40	40	40
Nameplate Capacity (MW)	835	901	374	232	374
Summer Peak Capacity (MW)	750	856	331	206	331
Capital Cost ($000) 2018$	$837,068	$906,588	$174,700	$114,766	$193,500
Electric Transmission Delivery ($000) 2018$	NA	$410,505	NA	NA	$74,804
Ongoing Capital Expenditures ($000-yr) 2018$	$6,200	$6,200	$1,784	$892	$1,784
Gas Demand ($000-yr) 2018$	$31,725	$19,058	$2,165	$1,342	$2,165
Capital Cost ($/kW) 2018$	$1,002	$1,006	$467	$495	$517
Electric Transmission Delivery ($/kW) 2018$	NA	$455	NA	NA	$200
Ongoing Capital Expenditures ($/kW-yr) 2018$	$7.42	$6.88	$4.77	$3.85	$4.77
Gas Demand ($/kW-yr) 2018$	$37.98	$21.14	$5.79	$5.79	$5.79
Fixed O&M Cost ($000/yr) 2018$	$6,592	$6,592	$1,253	$1,203	$1,253
Variable O&M Cost ($/MWh) 2018$	$1.04	$1.04	$0.99	$1.03	$0.99
Levelized $/kw-mo (All Fixed Costs) $2018	$15.26	$16.06	$5.91	$6.22	$8.06
Summer Heat Rate 100% Loading (btu/kWh)	6,359	6,848	9,264	10,025	9,264
Summer Heat Rate 75% Loading (btu/kWh)	6,547	6,874	9,738	10,581	9,738
Summer Heat Rate 50% Loading (btu/kWh)	6,985	7,334	11,120	12,515	11,120
Summer Heat Rate 25% Loading (btu/kWh)	8,004	8,404	11,558	13,430	11,558
Forced Outage Rate	3%	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	2	2	2
CO2 Emissions (lbs/MMBtu)	118	118	118	118	118
SO2 Emissions (lbs/MWh)	0.00	0.00	0.00	0.00	0.00
NOx Emissions (lbs/MWh)	0.05	0.05	0.90	0.32	0.90
PM10 Emissions (lbs/MWh)	0.02	0.02	0.03	0.03	0.03
Mercury Emissions (lbs/MMWh)	0.00	0.00	0.00	0.00	0.00

Table IV-15: Renewable Generic Information (Costs in 2018 Dollars)

Renewable Generic Information				
Resource	**Wind**	**Utility Scale Solar**	**Distributed Solar Commercial**	**Distributed Solar Residential**
ELCC Capacity Credit (%)	16.7%	50% declines to 30%		
Capacity Factor	50.0%	22.0%	18.0%	18.0%
Book life	25	25	25	25
Electric Transmission Delivery ($/kW)	500	200	0	0

Table IV-16: Storage Generic Information (Costs in 2018 Dollars)

Storage Generic Information	
Resource	**Battery**
Technology	Li Ion
Location Type	NA
Book life	40
Nameplate Capacity (MW)	321
Summer Peak Capacity (MW)	321
Storage Volume (hrs)	4
Cycle Efficiency (%)	85
Equivalent Full Cycles per Year	250
Electric Transmission Delivery ($000) 2018$	0
Levelized $/kw-mo (All Fixed Costs) $2023	$18.18

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NOT PUBLIC DATA HAS BEEN EXCISED

Table IV-17: Levelized Capacity Costs by Year

Levelized Capacity Costs by In-Service Year ($/kw-mo)								
COD	CT - 7H Greenfield	CT - 7F Brownfield	CT - 7H Brownfield	CC	Sherco CC	Base Battery	Low Battery	High Battery
2018	$8.06	$6.22	$5.91	$16.06	$15.26			
2019	$8.22	$6.34	$6.02	$16.38	$15.56			
2020	$8.38	$6.47	$6.15	$16.71	$15.87	$20.04	$17.86	$22.94
2021	$8.55	$6.60	$6.27	$17.05	$16.19	$19.44	$16.81	$23.19
2022	$8.72	$6.73	$6.39	$17.39	$16.51	$18.82	$15.73	$23.45
2023	$8.89	$6.86	$6.52	$17.73	$16.85	$18.18	$14.62	$23.71
2024	$9.07	$7.00	$6.65	$18.09	$17.18	$17.52	$13.47	$23.97
2025	$9.25	$7.14	$6.78	$18.45	$17.53	$16.84	$12.30	$24.24
2026	$9.44	$7.28	$6.92	$18.82	$17.88	$16.63	$11.75	$24.51
2027	$9.63	$7.43	$7.06	$19.20	$18.23	$16.41	$11.18	$24.78
2028	$9.82	$7.58	$7.20	$19.58	$18.60	$16.19	$10.60	$25.06
2029	$10.02	$7.73	$7.34	$19.97	$18.97	$15.95	$10.00	$25.34
2030	$10.22	$7.88	$7.49	$20.37	$19.35	$15.71	$9.38	$25.62
2031	$10.42	$8.04	$7.64	$20.78	$19.74	$15.83	$9.38	$26.06
2032	$10.63	$8.20	$7.79	$21.19	$20.13	$15.94	$9.37	$26.50
2033	$10.84	$8.36	$7.95	$21.62	$20.53	$16.04	$9.36	$26.94
2034	$11.06	$8.53	$8.11	$22.05	$20.94	$16.15	$9.35	$27.40
2035	$11.28	$8.70	$8.27	$22.49	$21.36	$16.26	$9.33	$27.86
2036	$11.50	$8.88	$8.44	$22.94	$21.79	$16.36	$9.31	$28.32
2037	$11.73	$9.05	$8.60	$23.40	$22.23	$16.46	$9.28	$28.80
2038	$11.97	$9.24	$8.78	$23.87	$22.67	$16.56	$9.25	$29.28
2039	$12.21	$9.42	$8.95	$24.34	$23.12	$16.65	$9.21	$29.78
2040	$12.45	$9.61	$9.13	$24.83	$23.59	$16.74	$9.17	$30.27
2041	$12.70	$9.80	$9.31	$25.33	$24.06	$16.83	$9.13	$30.78
2042	$12.96	$10.00	$9.50	$25.83	$24.54	$16.76	$9.00	$30.97
2043	$13.22	$10.20	$9.69	$26.35	$25.03	$16.66	$8.85	$31.12
2044	$13.48	$10.40	$9.88	$26.88	$25.53	$16.55	$8.70	$31.25
2045	$13.75	$10.61	$10.08	$27.42	$26.04	$16.42	$8.53	$31.35
2046	$14.02	$10.82	$10.28	$27.96	$26.56	$16.26	$8.35	$31.41
2047	$14.30	$11.04	$10.49	$28.52	$27.09	$16.08	$8.16	$31.44
2048	$14.59	$11.26	$10.70	$29.09	$27.64	$15.88	$7.95	$31.42
2049	$14.88	$11.48	$10.91	$29.68	$28.19	$15.65	$7.73	$31.35
2050	$15.18	$11.71	$11.13	$30.27	$28.75	$15.39	$7.49	$31.23
2051	$15.48	$11.95	$11.35	$30.88	$29.33	$15.70	$7.64	$31.85
2052	$15.79	$12.19	$11.58	$31.49	$29.91	$16.01	$7.79	$32.49
2053	$16.11	$12.43	$11.81	$32.12	$30.51	$16.33	$7.95	$33.14
2054	$16.43	$12.68	$12.05	$32.76	$31.12	$16.66	$8.10	$33.80
2055	$16.76	$12.93	$12.29	$33.42	$31.75	$16.99	$8.27	$34.48
2056	$17.10	$13.19	$12.54	$34.09	$32.38	$17.33	$8.43	$35.17
2057	$17.44	$13.45	$12.79	$34.77	$33.03	$17.68	$8.60	$35.87

Table IV-18: Base Renewable Levelized Costs by Year

Levelized Costs by First Full Year of Operation $/MWh (LCOE)				
	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$28.29	$46.12	$61.16	$92.16
2021	$32.32	$48.12	$64.63	$94.44
2022	$36.53	$53.73	$74.07	$105.71
2023	$40.91	$53.81	$73.54	$102.31
2024	$36.03	$53.87	$72.96	$98.77
2025	$50.24	$53.93	$72.35	$95.07
2026	$50.28	$53.97	$71.70	$91.23
2027	$50.32	$53.99	$71.00	$87.23
2028	$50.36	$54.01	$70.26	$83.07
2029	$50.41	$54.00	$69.47	$78.75
2030	$50.46	$53.98	$68.64	$74.26
2031	$51.13	$54.60	$69.31	$74.25
2032	$51.81	$55.21	$69.97	$74.23
2033	$52.50	$55.83	$70.64	$74.17
2034	$53.19	$56.45	$71.31	$74.08
2035	$53.89	$57.07	$71.98	$73.96
2036	$54.60	$57.70	$72.65	$73.81
2037	$55.31	$58.32	$73.32	$73.62
2038	$56.03	$58.96	$73.98	$73.40
2039	$56.76	$59.59	$74.65	$73.15
2040	$57.49	$60.23	$75.31	$72.86
2041	$58.23	$60.94	$75.87	$73.52
2042	$58.98	$61.66	$76.42	$74.18
2043	$59.73	$62.38	$76.97	$74.84
2044	$60.49	$63.10	$77.51	$75.49
2045	$61.26	$63.83	$78.04	$76.15
2046	$62.03	$64.57	$78.56	$77.43
2047	$62.81	$65.31	$79.08	$78.73
2048	$63.60	$66.05	$79.58	$80.05
2049	$64.39	$66.80	$80.08	$81.40
2050	$65.19	$67.55	$80.56	$82.76
2051	$66.49	$68.90	$82.17	$84.42
2052	$67.82	$70.28	$83.81	$86.11
2053	$69.17	$71.69	$85.49	$87.83
2054	$70.56	$73.12	$87.20	$89.59
2055	$71.97	$74.58	$88.94	$91.38
2056	$73.41	$76.08	$90.72	$93.20
2057	$74.88	$77.60	$92.54	$95.07

**Distributed Solar costs represent at the meter values before grossing up for losses.*

Table IV-19: Low Renewable Levelized Costs by Year

Low Levelized Costs by First Full Year of Operation $/MWh (LCOE)				
	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$25.70	$40.39	$46.57	$80.57
2021	$28.96	$41.44	$44.77	$80.58
2022	$32.43	$45.30	$50.58	$87.80
2023	$36.12	$44.66	$49.46	$82.47
2024	$30.57	$43.99	$48.30	$76.99
2025	$44.15	$43.29	$47.11	$71.34
2026	$43.59	$42.57	$45.87	$65.52
2027	$43.05	$41.82	$44.59	$59.54
2028	$42.55	$41.04	$43.26	$53.38
2029	$42.07	$40.23	$41.89	$47.05
2030	$41.62	$39.40	$40.48	$40.54
2031	$42.10	$39.43	$40.22	$40.29
2032	$42.57	$39.45	$39.94	$40.02
2033	$43.05	$39.46	$39.63	$39.73
2034	$43.53	$39.45	$39.30	$39.41
2035	$44.01	$39.43	$38.95	$39.06
2036	$44.50	$39.59	$38.57	$38.69
2037	$44.98	$39.74	$38.16	$38.29
2038	$45.47	$39.88	$37.72	$37.86
2039	$45.96	$40.01	$37.25	$37.41
2040	$46.45	$40.14	$36.75	$36.92
2041	$46.94	$40.51	$37.10	$37.03
2042	$47.43	$40.89	$37.46	$37.13
2043	$47.92	$41.26	$37.81	$37.22
2044	$48.41	$41.63	$38.17	$37.31
2045	$48.90	$42.01	$37.15	$37.38
2046	$49.40	$42.47	$37.76	$37.91
2047	$49.89	$42.93	$38.38	$38.45
2048	$50.38	$43.40	$39.01	$39.00
2049	$50.88	$43.87	$39.65	$39.55
2050	$51.37	$44.34	$40.30	$40.11
2051	$52.40	$45.23	$41.10	$40.92
2052	$53.44	$46.13	$41.93	$41.74
2053	$54.51	$47.06	$42.76	$42.57
2054	$55.60	$48.00	$43.62	$43.42
2055	$56.71	$48.96	$44.49	$44.29
2056	$57.85	$49.94	$45.38	$45.18
2057	$59.01	$50.94	$46.29	$46.08

**Distributed Solar costs represent at the meter values before grossing up for losses.*

Table IV-20: High Renewable Levelized Costs by Year

High Levelized Costs by First Full Year of Operation $/MWh (LCOE)				
	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$31.34	$47.98	$68.45	$98.01
2021	$36.42	$50.93	$73.59	$105.38
2022	$41.69	$58.00	$86.61	$124.02
2023	$47.16	$59.16	$88.34	$126.50
2024	$43.38	$60.35	$90.11	$129.03
2025	$58.71	$61.55	$91.91	$131.61
2026	$59.88	$62.79	$93.75	$134.24
2027	$61.08	$64.04	$95.63	$136.93
2028	$62.30	$65.32	$97.54	$139.67
2029	$63.55	$66.63	$99.49	$142.46
2030	$64.82	$67.96	$101.48	$145.31
2031	$66.11	$69.32	$103.51	$148.22
2032	$67.43	$70.71	$105.58	$151.18
2033	$68.78	$72.12	$107.69	$154.20
2034	$70.16	$73.56	$109.85	$157.29
2035	$71.56	$75.03	$112.04	$160.43
2036	$72.99	$76.53	$114.28	$163.64
2037	$74.45	$78.07	$116.57	$166.91
2038	$75.94	$79.63	$118.90	$170.25
2039	$77.46	$81.22	$121.28	$173.66
2040	$79.01	$82.84	$123.70	$177.13
2041	$80.59	$84.50	$126.18	$180.67
2042	$82.20	$86.19	$128.70	$184.29
2043	$83.85	$87.91	$131.28	$187.97
2044	$85.52	$89.67	$133.90	$191.73
2045	$87.23	$91.47	$136.58	$195.57
2046	$88.98	$93.30	$139.31	$199.48
2047	$90.76	$95.16	$142.10	$203.47
2048	$92.57	$97.06	$144.94	$207.54
2049	$94.43	$99.01	$147.84	$211.69
2050	$96.31	$100.99	$150.79	$215.92
2051	$98.24	$103.01	$153.81	$220.24
2052	$100.20	$105.07	$156.89	$224.65
2053	$102.21	$107.17	$160.02	$229.14
2054	$104.25	$109.31	$163.23	$233.72
2055	$106.34	$111.50	$166.49	$238.40
2056	$108.46	$113.73	$169.82	$243.16
2057	$110.63	$116.00	$173.22	$248.03

**Distributed Solar costs represent at the meter values before grossing up for losses.*

V. Market Purchases and Sales Carbon Rate

In order to estimate emissions rates associated with market purchases, the Company assumes an annual average carbon emissions pounds/MWh rate, as shown in the table below. These estimates were developed using MISO's MTEP Futures modeling results. Market sales emissions rates reflect an average emissions rate for our system resources and vary according to each individual scenario and sensitivity capacity expansion portfolio.

Table IV-21: Market Purchase Carbon Rate

Market Purchase CO2 Rate																				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
lbs/MWh	1372	1307	1241	1176	1110	1045	1042	1039	1036	1034	1031	1018	1006	993	980	968	955	943	930	917
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
lbs/MWh	905	892	880	867	854	842	829	817	804	792	779	766	754	741	729	716	703	691	678	666

W. Sherco CC Size Alternatives

In its October 17, 2019 hearing in this docket, the Commission directed the Company to model different size alternatives for the planned Sherco CC. The Company developed three size alternatives – two smaller units and one larger unit – to test in sensitivity modeling. Cost and performance assumptions for each of these alternatives are detailed in Table IV-22 below.

Table IV-22: Sherco CC Alternatives

Thermal Generic Information				
Resource	**Sherco CC**	**7HA.01 1x1**	**7HA.02 1x1**	**7HA.02 2x1**
Technology	7H	7H	7H	7F
Location Type	Brownfield	Brownfield	Brownfield	Brownfield
Cooling Type	Wet	Wet	Wet	Wet
Book life	40	40	40	40
Nameplate Capacity (MW)	835	405	592	1202
Summer Peak Capacity (MW)	750	395	576	1170
Capital Cost ($000) 2018$	$837,068	$473,751	$629,206	$941,199
Electric Transmission Delivery ($000) 2018$	NA	NA	NA	NA
Ongoing Capital Expenditures ($000-yr) 2018$	$6,200	$4,190	$4,190	$8,775
Gas Demand ($000-yr) 2018$	$31,723	$31,723	$31,723	$31,723
Capital Cost ($/kW) 2018$	$1,002	$1,171	$1,064	$783
Electric Transmission Delivery ($/kW) 2018$	NA	NA	NA	NA
Ongoing Capital Expenditures ($/kW-yr) 2018$	$7.43	$10.35	$7.08	$7.30
Gas Demand ($/kW-yr) 2018$	$37.99	$78.41	$53.63	$26.38
Fixed O&M Cost ($000/yr) 2018$	$6,592	$7,150	$7,150	$8,647
Variable O&M Cost ($/MWh) 2018$	$1.04	$1.72	$1.72	$1.09
Levelized $/kw-mo (All Fixed Costs) $2018	$15.26	$18.36	$14.11	$10.95
Summer Heat Rate 100% Loading (btu/kWh)	6,359	6,322	6,208	6,452
Summer Heat Rate 75% Loading (btu/kWh)	6,547	6,419	6,257	6,403
Summer Heat Rate 50% Loading (btu/kWh)	6,985	6,681	6,516	6,812
Summer Heat Rate 25% Loading (btu/kWh)	8,004	7,553	7,388	7,479
Forced Outage Rate	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	5	5
CO2 Emissions (lbs/MMBtu)	118	118	118	118
SO2 Emissions (lbs/MWh)	0.00	0.00	0.00	0.00
NOx Emissions (lbs/MWh)	0.05	0.05	0.05	0.05
PM10 Emissions (lbs/MWh)	0.02	0.02	0.02	0.02
Mercury Emissions (lbs/MMWh)	0.00	0.00	0.00	0.00

V. RESOURCE OPTIONS

Our Strategist, and now EnCompass, modeling outcomes are highly dependent on inputs and assumptions. Appendix F6 of our initial filing discussed in more detail the resources included in our baseline, the resource options from which Strategist modeling could choose, and a non-exhaustive list of emerging technologies the Company is tracking and may explore further in order to meet our 2050 carbon-free energy goals. While many of these inputs and options have not changed since our initial filing in July 2019, there are some changes related to resource procurements and others to the types and attributes of resources our models available to the model to select for capacity expansion plans.

A. Baseline Resources – Updates to Existing Resources

In this section we outline the baseline resources available to the model and discuss any changes to these resources since our initial July 2019 Resource Plan filing. These include changes initiated by Commission decisions that were pending at the time of filing, project status changes, and newly approved resources. We also note that our approach to modeling baseline resources has changed since our initial filing. At that time, we included any resources that were existing, approved or pending approval with the Commission. Based on feedback received, we have included only existing and approved resources as of January 31, 2020. We implemented this modeling "lock-in" date to allow sufficient time to conduct Strategist and EnCompass modeling. To the extent projects were approved between February 1 and the June 30, 2020 Supplement filing date, we include a narrative description, and we believe including any resources approved in the intervening time period would not meaningfully change our Supplement Preferred Plan.

We provide a brief accounting of changes to our baseline resources and updated resource tables below.

1. Coal

There are no material changes to the magnitude of our coal-fired generation capacity since our initial filing in July. However, we received feedback from the Commission directing us to align the existing retirement date for Sherco Unit 3 with its current

2034 financial end of life date,[28] rather than the 2040 operational life used in our initial filing.

We also note that the Commission recently voted to approve, in Docket E-002/M-19-809, the Company dispatching our King and Sherco 2 units on a seasonal basis. We have incorporated seasonal dispatch into modeling, as it represents a significant operational change that impacts modeling outcomes. To reflect seasonal dispatch practices in modeling, we do not allow dispatch of King and Sherco 2 from March-May and September-November from the fall of 2020 to 2023. After 2023, Sherco 2 is retired and King is modeled on economic dispatch through its retirement date in a given scenario.

We summarize our existing coal units as applied in our modeling in Table V-1 below.

Table V-1: Baseline Coal Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW, max cap)	Existing Retirement/ Contract Expiration
Allen S King	Steam Turbine (ST)	Own	511	2036
Sherco 1	ST	Own	680	2026
Sherco 2	ST	Own	682	2023
Sherco 3[29]	ST	Own	517	2034

2. *Nuclear*

We have not made any changes to our nuclear units from our initial filing. For ease of reference, we have copied the Table from our July 2019 filing summarizing our nuclear units as applied in our modeling.[30]

[28] As reported in the Company's Annual Remaining Lives filing. The most recent filing can be found in Docket No. E002/D-19-161
[29] Note that this represents only the portion of Sherco 3 under our ownership.
[30] Note that we continue to test day-ahead flexible operations at our nuclear units, as discussed further in Attachment A Section VIII: Nuclear Updates. However, nuclear flexible dispatch is not currently factored into our modeling approach.

Table V-2: Baseline Nuclear Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW, max cap)	Existing Retirement/Contract Expiration
Monticello	Boiling Water Reactor	Own	646	2030
Prairie Island 1	Pressurized Water Reactor (PWR)	Own	546	2033
Prairie Island 2	PWR	Own	546	2034

3. Natural Gas and Oil

The changes we made to our natural gas and oil units for this Supplement are based on Commission decisions, to align unit retirement dates with existing remaining/financial lives, and to reflect black start needs. In October 2019, the Commission denied the Company's request to acquire the Mankato Energy Center (MEC) units as Northern States Power-owned assets[31] and thus the units are, and will remain, merchant generators.[32] Accordingly, MEC Units 1 and 2 are in our baseline resources through their prevailing purchased power agreement (PPA) expiration dates of 2026 and 2039, respectively. Consistent with treatment of other PPAs, we do not assume either unit is re-contracted at the end of its PPA. We also modified the retirement dates for the Angus Anson units and Blue Lake 7 and 8 units to match their financial end of life dates approved in our last *Annual Remaining Lives* docket,[33] and the retirement date for French Island units to align with their current fuel contracts.

In our initial filing we noted that our black start units are aging, and we anticipated addressing this need in future filings. For this Supplement, we have taken steps to reflect future needs in modeling, by including placeholder capacity and associated life extension costs for black start resources in both Minnesota and Wisconsin, to 2030. We note that this approach does not equate to a proposal for specific unit life extension, rather is a placeholder for modeling until we complete our full analyses. In the table below we represent this placeholder capacity in a separate line item. In total

[31] *See* Docket No. IP6949, E002/PA-18-702. ORDER DENYING PETITION AND REQUIRING SUPPLEMENTAL MODELING. (December 19, 2019).
[32] The Commission approved the Company's request to acquire the units as merchant affiliate assets in Docket No. E002/AI/19-622. However, the Company has since agreed to sell the MEC facility to Southwest Generation. The sale is expected to close in the third quarter of 2020. The units will remain under contract to sell to NSP through their current contract dates. *See* Docket No. E002/AI-19-622 LETTER – MANKATO ENERGY CENTER I AND II AFFILIATED INTEREST REQUEST (April 6, 2020).
[33] *See* Docket No. E,G002/D-19-161.

this placeholder capacity represents just over 600 MW of max capacity and an unforced capacity of approximately 430 MW. Further discussion on our black start resources and how they are handled in modeling is available in Attachment A Section VII: Black Start.[34]

Finally, we note that the planned Sherco CC is also included in our baseline modeling, given that the unit is provided for via Minnesota statute. [35] This unit is modeled as a 2-by-1 unit, adding 728 MW of accredited capacity (corresponding to 835 MW installed capacity), starting in 2027 after the current Sherco 1 coal unit retires. Per the Commission's direction, we have also conducted sensitivity modeling that tests alternate Sherco CC sizes to determine the economic impact of a differently sized unit. These sensitivities are outlined further below in Section B.3.

We summarize each of the units as applied in our modeling in the below Table.

[34] Note that some information regarding black start units and plans is subject to trade secret protection; this information is consolidated in one section to reduce the number of redactions necessary in this filing.
[35] *See* Minnesota Session Laws-2017 Ch. 5. H.F. No. 113.

Table V-3: Baseline Natural Gas and Oil Resources[36]

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW, max cap)	Existing or Planned Retirement/Contract Expiration
Black Dog 52	CC	Own	298	2032
High Bridge	CC	Own	606	2048
Riverside	CC	Own	508	2049
Mankato Energy Center Unit 1	CC	PPA	375	2026
Mankato Energy Center Unit 2	CC	PPA	345	2038
LSP – Cottage Grove	CC	PPA	245	2027
Angus Anson 2-3	CT	Own	218	2040
Angus Anson 4	CT	Own	168	2044
Black Dog 6	CT	Own	232	2058
Blue Lake 7,8	CT	Own	351	2044
Inver Hills 1-6	CT	Own	369	2026
Wheaton 1-4	CT	Own	241	2025
Cannon Falls Energy Center	CT	PPA	358	2025
Blue Lake 1-4	Oil	Own	191	2023
French Island 3,4	Oil	Own	160	2030
Wheaton 6	Oil	Own	70	2025
Sherco CC	*CC*	*Own*	*835*	*No retirement date assigned*
Black Start – Minnesota and Wisconsin	*CT*	*Own*	*Approx. 620 MW*	*Extended from current end of lives to 2030*

4. *Biomass*

The Company owns and operates, and maintains PPAs for, various biomass facilities. We include in this category refuse-derived fuel (RDF), landfill (LND) and digester (DIGT) resources as well. Since our initial filing, the 12 MW PPA with KODA Resources and the 0.5 MW PPA with Heller Dairy have expired and were removed

[36] Units in italics represent capacity that is included in the baseline, but either not yet online (Sherco CC) or represent placeholder capacity (black start unit extension placeholder).

from the resource baseline. Additionally, Diamond Dairy terminated its 0.4 MW PPA early in 2019 and was removed from the baseline resources. We also modified French Island 1 and 2 retirement dates for alignment with fuel contracts and retirement dates for units 3 and 4. Finally, we have extended the PPA for the Waste Management (WM) Renewable Energy facility listed below for an additional two years beyond its previous expiration date in 2020; however this capacity is not factored into modeling because the PPA extension occurred after the January 31 resource lock-in date.

We summarize our modeled biomass resources below.

Table V-4: Baseline Biomass Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW, max cap)	Retirement/ Contract Expiration
Bayfront 5,6	Bio	Own	26	2035
French Island 1,2	Bio	Own	15	2030
Red Wing 1,2	Bio	Own	18	2027
Wilmarth 1,2	Bio	Own	17	2027
St. Paul Cogen	Bio	PPA	24	2023
WM Renewable Energy	LND	PPA	4	2020
Gunderson	LND	PPA	1	
Barron County	RDF	PPA	2	2022
Hennepin Energy Recovery Center	RDF	PPA	34	2024
Greenwhey	DIGT	PPA	3	2023

5. *Hydroelectric*

The Company owns, operates and maintains PPAs for hydropower resources, with the majority of our current capacity coming from PPAs with Manitoba Hydro. The only change from our initial filing is the removal of two small hydro PPAs – Neshonoc and Rapidan. Both of these PPAs have expired, and new agreements were not yet finalized as of the end of January 2020. As in our initial filing, we also include in modeling our diversity agreement with Manitoba Hydro, which is not reflected in the table below. This agreement provides the NSP System with 342 MW of accredited capacity (350 MW max capacity) in the summer only – and Manitoba Hydro receives 350 MW capacity in the winter only – through 2025.

We summarize the hydropower resources as applied in our modeling in the below Table.

Table V-5: Baseline Hydroelectric Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW, max cap)	Retirement/ Contract Expiration
Byllesby	Hydro	PPA	2	2021
Hastings	Hydro	PPA	4	2033
St. Cloud	Hydro	PPA	9	2021
Dairyland	Hydro	PPA	4	-
Eau Galle	Hydro	PPA	0.3	2026
DG Hydro	Hydro	PPA	0.4	-
LCO Hydro	Hydro	PPA	3	2021
SAF Hydro	Hydro	PPA	9	2031
WTC Angelo Dam	Hydro	PPA	0.2	2024
MN Grouped Hydro	Hydro	Own	14	-
WI Grouped Hydro	Hydro	Own	260	-
Manitoba Hydro	Hydro	PPA	375	2025
Manitoba Hydro	Hydro	PPA	125	2025 (2021 start)

6. *Wind*

Most of the wind resources listed in our initial filing are unchanged, with the exception of Lake Benton I and the Crowned Ridge Projects. Lake Benton II's PPA expired in 2019 and thus was removed from modeling; however, the project was repowered and re-contracted as Lake Benton Repower, which is included below. Crowned Ridge I and II were originally approved by the Commission in Docket No. E002/M-16-777 as two 300 MW projects; energy from Crowned Ridge I would be procured via PPA, and Crowned Ridge II would be acquired by the Company upon its completion. In August 2019, we notified the Commission that the project's Seller intended to reduce the size of the projects by 100 MW each as a result of transmission interconnection costs assigned to a portion of the project.[37] The Company and Seller amended both contracts to reflect this change, and we filed these amendments with the Commission in December 2019.[38] Accordingly, we have reduced the size of

[37] *See* In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of Wind Generation from the Company's 2016-2030 Integrated Resource Plan, Docket No. E002/M-16-777, XCEL ENERGY LETTER: CROWNED RIDGE UPDATE (August 30, 2019).

[38] *See* In the Matter of the Petition of Xcel Energy for Approval of the Acquisition of Wind Generation from the Company's 2016-2030 Integrated Resource Plan, Docket No. E002/M-16-777, PURCHASED POWER AGREEMENT AND PURCHASE AND SALE AGREEMENT AMENDMENTS. (December 20, 2019)

Crowned Ridge I and II to 200 MW each in our modeling to reflect the current contracts.[39]

As of our January 31, 2020 resource assumptions lock-in, there were two proposed acquisitions yet pending.

- *Deuel Harvest PPA.* This project, for 100 MW of wind coming online by the end of 2021 and expiring in 2036, was approved by the Commission in February 2020.[40] The Company will use this PPA to serve the Company's planned and approved Renewable*Connect expansion.[41]
- *Mower County Wind.* The Company has proposed to acquire a repowered 98.9 MW Mower County Wind facility.[42] The existing PPA for the facility runs through 2026. If the acquisition is approved, we would expect the repowered facility to come online at the end of 2020 and operate until 2045. The Mower County facility was modeled in accordance with the existing PPA in our analyses.

We summarize the wind resources included in our baseline modeling below.

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[39] As noted in our March 3, 2020 Reply Comments in Docket No. E002/M-16-777.
[40] *See* Docket No. E002/M-19-268 ORDER – IN THE MATTER OF XCEL ENERGY'S PETITION FOR APPROVAL OF A WIND ENERGY PURCHASE AGREEMENT WITH INVENERGY WIND ENERGY DEVELOPMENT, LLC. (February 12, 2020).
[41] Approved in Docket No. E002/M-19-33.
[42] *See* Docket No. E002/PA-19-553.

Table V-6: Baseline Wind Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW, max cap)	Retirement/ Contract Expiration
Big Blue	Wind	PPA	36	2032
Chanarambie	Wind	PPA	86	2023
Community Wind North	Wind	Own	26	2044
Fenton	Wind	PPA	206	2032
McNeilus Group	Wind	PPA	37	2028
Jeffers	Wind	Own	44	2044
MinnDakota	Wind	PPA	150	2022
Moraine II	Wind	PPA	50	2029
Community Wind South (Zephyr)	Wind	PPA	31	2032
Lake Benton I	Wind	PPA	104	2028
Odell	Wind	PPA	200	2035
Prairie Rose	Wind	PPA	200	2032
FPL Mower Co	Wind	PPA	99	2026
Ridgewind	Wind	PPA	25	2031
Border	Wind	Own	150	2040
Courtenay	Wind	Own	200	2041
Grand Meadows	Wind	Own	100	2033
Nobles	Wind	Own	200	2035
Pleasant Valley	Wind	Own	200	2040
Crowned Ridge (Owned)	Wind	Own	200	2044
Freeborn	Wind	Own	200	2045
Foxtail	Wind	Own	150	2044
Blazing Star I	Wind	Own	200	2044
Blazing Star II	Wind	Own	200	2045
Lake Benton Repower	Wind	Own	100	2044
Dakota Range 1 & 2	Wind	Own	300	2046
Dakota Range 3	Wind	PPA	150	2032
Clean Energy	Wind	PPA	100	2039
Crowned Ridge (PPA)	Wind	PPA	200	2044
Small Wind[43]	Wind	PPA	270	Various

[43] Includes PPAs of 20 MW or less; this number was adjusted from the initial filing to correct a counting error.

7. Solar

The utility-scale solar units included in our modeling baseline have not changed since our initial filing. We have however, updated our distributed solar (DG Solar) and Community Solar Garden totals to include additional capacity that was not yet accounted in our initial filing. We note that one project was pending approval as of the January 31 lock-in date and is therefore not included in our baseline modeling. Elk Creek Solar is an 80 MW project proposed to come online by the end of 2021 and expire in 2041.[44] We plan to use this PPA to serve our approved Renewable*Connect expansion.[45]

We summarize the solar resources included in our baseline modeling below.

Table V-7: Baseline Solar Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW, max cap)	Retirement/ Contract Expiration
Slayton	PV	PPA	2	2033
St. John's	PV	PPA	0.4	2030
School Sisters of Notre Dame	PV	PPA	0.7	2036
Aurora	PV	PPA	99	2036
Marshall	PV	PPA	62	2042
North Star	PV	PPA	99	2041
DG Solar[46]	PV		80	Various
Community Solar Garden	PV	PPA	658	Various

B. Generic Future Resource Options

Many of the generic future resource options made available for the model to select in capacity expansion modeling remain unchanged from our initial filing. However, we have made certain changes in response to feedback from the Commission and stakeholders. These changes broadly fall along two lines: 1) updates to our approach for resources included in capacity expansion modeling; and 2) additional resource options developed to test in sensitivity modeling.

[44] *See* Docket No. E002/M-19-558.
[45] Approved in Docket No. E002/M-19-33.
[46] Includes Solar*Rewards, Made in MN Solar, and Other RDF Solar not accounted for in other sections above.

First, we have updated certain assumptions related to generic resources that are available to fill identified energy and capacity needs in modeling, as follows:

- *Cost estimates and accredited capacity for renewable and storage resources.* We have updated cost trajectories to utilize the 2019 version of the NREL ATB. As a result of this update, solar, wind, and storage prices have declined across the modeling period. We further detail these cost assumptions in Attachment A Section IV and discuss below. We have also updated accredited capacity assumptions for wind and solar resources, as described in Section II: Modeling Framework and Results and discussed further below.
- *Streamlining natural gas CT plant options.* For this Supplement, in order to streamline the modeling process, we conducted pre-screening to narrow the available generic CT options from considering multiple brownfield and greenfield configurations to one single generic greenfield option.

Second, we have also incorporated the Commission's feedback and developed specific hybrid renewable-plus-storage resource options, including wind-plus-storage and solar-plus-storage. We use these new resource options in our Preferred plan sensitivities to assess whether such a paired resource would be selected as cost-effective.

Finally, we developed cost estimates to test different sizes of a combined-cycle unit (CC) located at the Sherco site in the context of our Supplement Preferred Plan. These sensitivity model runs help us examine the economic impact of sizing the unit larger or smaller relative to the size included in our baseline modeling.

1. *Changes to Generic Resource Options*

- *Wind:* Our generic wind resource option is sized at 750 MW nameplate capacity, which corresponds to approximately 125 MW of accredited capacity). Whereas in our initial filing, wind resources were assigned an ELCC of 15.6 percent, in line with the most recent MISO average values available at the time, we modified our approach to using even more recently available ELCC value for Zone 1, which is 16.7 percent. This modification better reflects higher production and average capacity credits assigned to existing wind resources in our region, relative to other parts of MISO. Wind costs are based on 2019 ATB forecasts for wind Technology Resource Group (TRG) 2,[47] adjusted for tax credit values in relevant years, and estimated transmission interconnection costs associated with greenfield facilities. In our initial filing we assumed that a greenfield wind project would be subject to $400/kW transmission interconnection costs. Since then, it has become apparent that transmission constraints in the MISO West region are increasingly severe, such that the average identified upgrade cost in some studies is upwards of $2,000/kW. In order to account for these near-term constraints in our modeling, we have not made wind available to the model to select prior to 2026 in our baseload scenario modeling. Starting in 2026 we apply a $500/kW interconnection cost to generic wind resources.

- *Utility-scale Solar:* Our generic solar option is sized at 500 MW on a nameplate basis. Accredited capacity is dependent upon the declining Effective Load Carrying Capability assumption used in modeling for solar. In the first several years of the analysis period, we use the current 50 percent ELCC, corresponding to a 250 MW accredited capacity for generic new solar. By 2033, however, the modeled ELCC declines to 30 percent, which would correspond to 150 MW of accredited solar capacity. This assumption is consistent with those MISO uses in their latest MTEP Futures modeling. For solar cost assumptions, we have used updated 2019 ATB forecasts, adjusted for tax credit values in relevant years and estimated transmission interconnection costs. In light of increasing transmission constraints, we have assumed higher solar interconnection costs in this Supplement – increasing from $140/kW to $200/kW. We believe increasing the interconnection cost for solar resources is a reasonable approach based on the trends observed in MISO's most recent interconnection studies.

- *Natural Gas CT:* As noted above, we streamlined the CT unit options the model could select for the purposes of this Supplement. To do so, we conducted prescreening that narrowed the options made available to modeling to only one 374 MW nameplate (321 MW accredited) greenfield option and eliminated brownfield options previously available. The cost and configuration assumptions included for the greenfield unit remain unchanged from our initial filing.

- *Natural Gas CC:* Our approach to modeling generic CCs has not changed in this Supplement. We made one greenfield CC option available to the model, of

[47] Note that in our initial filing we used TRG 1 costs for wind resources; however, we believe the capacity factors in TRG 2 are likely better aligned with remaining available sites in our region for greenfield wind, given already substantial build out.

approximately 900 MW (856 MW accredited), with cost assumptions developed utilizing external consultant analyses.

- *Battery Energy Storage:* As in our initial filing, we have made a generic stand-alone four-hour battery storage option an available option in our modeling. The generic unit continues to be sized at 321 MW. However, whereas previously our resource cost assumptions were based on bids received in our Public Service Company of Colorado operating company affiliate's 2017 all-source solicitation and adjusted for an assumed technology improvement trajectory, for this update we have used the 2019 ATB cost forecasts for lithium-ion battery storage resources.

- *Demand Response:* Like our initial modeling, we modeled incremental demand response (DR) resources in "Bundles" of potential measures, informed by the Brattle Group's *Demand Response Potential Study*.[48] For the purposes of Supplement modeling, we updated the bundles to account for the passage of time and observed historical performance in certain programs included in the bundles. In the previous modeling the incremental first Bundle was added into our proposed Preferred Plan after the capacity expansion runs optimized in the model. However, for this Supplement, the first Bundle is included in our baseline resource modeling, and it continues to achieve the Commission's targeted 400 MW of incremental DR by 2023[49]. Our updated five-year action plan for DR resources is included in Attachment A Section XIV.

- *Energy Efficiency:* Consistent with our initial filing, we utilized the statewide *Minnesota Energy Efficiency Potential Study* (2020-2029) to develop three Bundles that would be available for the model to select as supply-side resources. These Bundles have not changed since our initial filing, and we have included the first two Bundles in our portfolio modeling.

2. New Hybrid Renewable-Plus-Storage Resource Options

As noted above, the resources available to our capacity expansion models to select included standalone wind, solar and storage individually. However, there are potential combinations of these resources; wind or solar paired with storage, that provide an opportunity for variable renewables to be more flexible. Like many of our peer utilities, we anticipate that there will be opportunities to co-locate storage and

[48] Provided as Appendix G2 to our initial filing in this docket.
[49] We note that our modeling for this Supplement does not incorporate potential changes to energy demand or DR adoption as a result of the ongoing COVID-19 health crisis and accompanying economic impacts. We do not yet know the full extent of these shifts but will continue to evaluate them in the coming months.

renewable resources in the future in a way that reduces costs for customers. To capture this possibility, and in response to Commission feedback, we added a sensitivity analysis that examines the potential for renewable-plus-storage resources to economically displace resources included in our initial baseload scenarios.

For both hybrid units – wind-plus-storage or solar-plus-storage – we assume the energy storage resource is a 125 MW four-hour lithium ion battery. The solar and wind components are sized the same as the standard generic options. Capacity accreditation values for the hybrid units remain separately counted. For example, we assume the wind portion of a hybrid wind-plus-storage unit is assigned a 16.7 percent ELCC, while the storage portion receives 100 percent ELCC. The hybrid unit's cost is assumed to be equal to the LCOE of a standalone wind unit, plus the levelized $/kW cost of the battery. We do not assign incremental transmission costs to the storage addition. We follow the same process for a hybrid solar-plus-storage resource; however, such a resource qualifies to receive the solar Investment Tax Credit (ITC), per the year it is placed into service, and our levelized cost assumptions reflect this benefit.[50] Additional detail on our hybrid-resource cost assumptions is available in Attachment A Section IV.

3. *Sherco CC Size Sensitivities*

Per the November 2019 Order requiring additional modeling,[51] we have developed sensitivities to test the effect of different Sherco CC sizes on the cost effectiveness of our Supplement Preferred Plan. To do so we developed cost and operational assumptions around three size options, both larger and smaller than the 835 nameplate (and 750 net summer) MW size option included in our scenario modeling. Testing a breadth of options in our sensitivity analysis results in a better assessment of the directional impact on our overall system costs.

As discussed in our initial filing, we developed assumptions for the baseline Sherco CC assumptions using a combination of internal estimates and available technology information collected from external sources. The Sherco CC assumptions included in our Supplement's baseline modeling are substantially the same as the ones we used in in our initial modeling.[52] Based on further discussions with vendors and internal

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[50] Equal to 10 percent of the total value of the system, for systems beginning construction after 2021.
[51] *See* Docket No. E002/RP-19-368. ORDER SUSPENDING PROCEDURAL SCHEDULE AND REQUIRING ADDITIONAL FILINGS (November 12, 2019) at Order Point 2.B.
[52] We have applied limited changes to reflect evolving gas supply estimates; whereas we had previously assumed an annual gas demand charge as well as a contribution in aid of construction (CIAC) charge, we now have rolled all assumed gas supply costs into an annual demand charge of approximately $41 million.

analysis, we developed three alternately sized options to test in sensitivity analyses. We note that these options are only representative; actual configurations and costs depend upon vendor and site-specific parameters that would be determined in project development.

Table V-8 contains a summary of the three size options we tested in our Sherco CC sensitivities. Additional detailed information is available in Attachment A Section IV.

Table V-8: Summary of Sherco CC Size Sensitivity Options

Analysis Option	Size (MW, Nameplate)	Size (MW, Net Summer)	Configuration	All-in Cost ($/nameplate MW)
Baseline	835	750	2 CTs, 1 ST (2x1) Wet Cooled No Duct Firing	$1,002,000
Small – 1	405	395	1 CT, 1 ST (1x1) Wet Cooled No Duct Firing	$1,171,000
Small – 2	592	577	1 CT, 1 ST (1x1) Wet Cooled No Duct Firing	$1,064,000
Large – 1	1,077	1,046	2 CTs, 1 ST (2x1) Wet Cooled No Duct Firing	$874,000

VI. RESOURCE ATTRIBUTES

Integrated Resource Planning is intended to identify the size, type, and timing of resources we will need on our system in the future and has traditionally been largely focused on an examination of capacity adequacy. One objective inherent in this process, although not explicitly stated, is consideration of resource *attributes* and the importance of aligning the types of resources we need for the reliability of our system and broader grid. While we model our capacity expansion plans based on specific technology types' cost and operational characteristics, we also must look across resource types to ensure a balanced portfolio that provides appropriate capacity, energy, and flexibility attributes in aggregate.

Examining a portfolio's resource attributes is becoming increasingly important as capacity adequacy decouples from other reliability attributes. Variable resources make up an increasing share of our future generation mix; these resources provide carbon emission avoidance benefits to our system, but also represent a significant shift in operating characteristics relative to the legacy grid. Traditional thermal and some hydropower resources are considered "firm," such that they can supply electricity reliably, on demand, for long durations. Many also provide ancillary grid stability and strength benefits that help the system respond instantaneously to – and ride through – variance in frequency or voltages. Some are also designed to provide flexibility, meaning that they can be ramped up or down relatively quickly in response to changes in customer demand. Variable renewables like wind and solar have introduced new opportunities to provide zero-carbon energy, at low or zero-marginal cost. As such, they are generally given preference in a grid operator's dispatch order. However, as they are variable rather than firm, other resources on the grid must be able to accommodate fluctuation in their output as it occurs and ensure energy and capacity adequacy every hour of every day.

Ultimately, each type of resource contributes different benefits, but in combination, the same resource attributes the grid has had in the past must be ensured going forward to guarantee we can meet customers' electricity needs. As variable renewables increase as a share of the total energy and capacity available on the grid, the grid becomes more complex, with more variations in net load for which other resources must be prepared to provide. Our resource planning models help assess these needs, but as the grid's complexity increases, we need to employ additional modeling and analyses to adequately plan for a clean, reliable future. Capacity expansion models like Strategist have been useful to identify capacity adequacy, as they integrate resource adequacy (RA) guidance we receive from MISO. However, our traditional Strategist modeling – which relies on load duration curves to evaluate whether a portfolio will be capacity and energy sufficient in a given year – cannot adequately capture this increasing variability, and thus will no longer be sufficient to ensure our resource plans will meet customer needs in every hour of every day. As such, we have added the EnCompass hourly production cost modeling capabilities to our suite of portfolio evaluation tools for this Supplement and will rely primarily on EnCompass for our Resource Plan modeling going forward. Production cost modeling tools such as EnCompass include features such as hourly chronological dispatch analysis, which help us evaluate potential energy adequacy and flexibility shortfalls on an intraday basis, across a full analysis year. It provides the more granular analysis necessary to uncover potential reliability challenges associated with transitioning our system to include, and rely on, more variable resources.

As more emitting thermal generation retires from our grid and is replaced with variable renewable and fast-response – but use-limited resources – the tools and measures we use to conduct long-term resource planning will continue to evolve. In fact, there continue to be new approaches developed to value these attributes in planning processes. The Company will continue to evaluate the best ways to incorporate resource attributes into its planning processes in the future, as we navigate the transition to achieve 100 percent zero-carbon generation by 2050.

A. Resource Attributes' Intersection with Resource Types

As discussed above, our resource planning process primarily evaluates the size, type, and timing of resource additions we need to serve customers reliably in the future. Our baseline resources – those already on our system – are modeled using known operating characteristics. For future resource additions, we model individual generic resource options that our capacity expansion model can select – whether wind, solar, natural gas combustion turbines, battery storage, or others – in order to appropriately capture different technology costs and operating characteristics of each resource.

Historically, the grid consisted primarily of traditional thermal and hydropower sources, and the attributes of these resources could be relatively easily matched to grid needs. Coal and nuclear resources provided a grid resilience "backbone" attributable to their large rotating generators that help maintain important inertia, stability, and strength for the grid. To the extent the grid needed flexibility for changing loads, some coal units and natural gas and fuel oil peaking plants could ramp up or down to meet that need. These resources all have secure fuel supplies, either through firm energy contracts, on-site storage, or other long-duration refueling planning.

The grid is now transitioning away from many of these traditional resources. Thermal plants are retiring and variable and use-limited resources such as wind, solar and battery energy storage are increasing. This means that the quantity of resources that have traditionally provided grid resilience attributes are decreasing, and the quantity of resources that require the grid to operate more flexibly are increasing. Overall, grid operators must ensure that, as the mix of resources on the grid continues to evolve, all the necessary resource attributes that ensure a reliable supply and delivery of electricity to customers are still present.

Below we map these attributes against the resources that can provide them and discuss each attribute.

Figure VI-1: Resource Attributes Mapped to Resource Types

		Resource Types	**Firm Traditional – Baseload**	**Firm Traditional – Intermediate or Peaking**	**Variable Renewables**	**Fast-Burst Balancing**	**Transmission Solutions**
Resource Attributes	**Response Duration & (Frequency of Need)**	***Examples***	*Coal, Nuclear, Biomass, Run-of-river Hydro*	*CC, CT*	*Standalone Wind, Solar*	*DR, Standalone Battery Storage*	*Synchronous condensers, HVDC, Static Var Compensators*
Essential Reliability Services	Minutes – Milliseconds (Continuous)	*Spinning reserve, inertial response, frequency regulation, voltage control*	Nuclear / Non-nuclear				
Flexibility	Minutes – Hours (Daily)	*Ramp rates, cycling, minimum runtime*					
Energy Availability	Hourly - Multiday (Continuous)	*Long duration availability, secure fuel supply*					
Black Start	Minutes – Hours (Infrequent, emergency only)	*Starts and runs on zero load, secure fuel supply*	Nuclear / Non-nuclear				

1. *Essential Reliability Services – System Strength and Stability*

System strength and system stability are two related – but distinct – aspects of essential reliability services that work together to ensure the grid can detect and respond to periodic disturbances that may otherwise cause outages or other voltage disturbances. System strength refers to the grid's ability to maintain stable voltages, and for grid control systems to be able to detect differences between normal and abnormal conditions in the event of a grid disturbance. The stronger a system is, the more quickly and capably it can respond to – and mitigate – a destabilizing event. Controlling voltages on the grid at all locations, at all times, to acceptable levels is essential for power quality and reliability.

System stability refers to the grid's ability to respond to these disturbances to maintain balance; it includes factors such as frequency regulation, spinning reserve, and inertial response capabilities. Frequency regulation refers to how grid assets respond to rapid changes continuously occurring on the grid and ensure that the energy produced on the system precisely matches customer usage at all times. Spinning reserve is a generator's capacity that is available but remains available/unloaded, so that it can be used to provide extra generation if needed to meet customer needs. Inertia is an attribute of generators with large, spinning rotors that helps the system "ride through" disturbances to the grid that, without inertia, would impact reliability.

In general, firm traditional resources – such as conventional thermal and hydroelectric generation – can and have provided a wide range of essential reliability services. For example, they provide system strengthening voltage control because they are synchronous generators, with excitation systems controlled by Automatic Voltage Regulators. These are essential for the generators' own stability and also enable the generators to provide full reactive range for voltage control, down to their minimum generation limits. Many can also provide a broad range of system stability services, via governor controls systems that allow primary frequency response up to their rating, and – as a dispatchable resource – can be operated with headroom for providing spinning reserve. One exception is nuclear power, which does not provide fast response services, but is an excellent source of inertial response.

Variable renewable resources can provide some of these essential reliability services through pitch controls, inverter-based voltage control, and curtailment. Their inverters can provide fast voltage/reactive control capabilities over a wide range of active power conditions, although not at the same level as synchronous resources. However, these resources are also typically grid-following, which means they have to rely on a reference signal from the grid to operate reliably through a disturbance; if a voltage event disrupts this reference signal, the resource may not be able to respond effectively. Further, variable renewables sometimes have technical potential to provide essential reliability services, but the way they are operated and dispatched make them less practical sources. For example, variable resources like wind and solar typically run at full output, for economic and environmental reasons. Thus, they can be curtailed from normal operating conditions to respond to over-frequency events; but they are rarely intentionally operated under full capacity for long durations in order to provide spinning reserves or respond to under-frequency events.

Fast-burst balancing resources – such as DR or standalone battery storage – are both technically capable of providing various essential reliability services, but their availability to do so varies. Battery energy storage can provide extremely fast reactive power and voltage control services, but it is duration-limited; depending on the size and configuration of the battery and state of charge, it may not be able to provide these services for long periods of time. DR resources have traditionally controlled only real power usage and have not provided direct voltage and reactive power control. Battery energy storage is well suited to carry spinning reserve and provide primary frequency response if the battery's state of charge at a given time allows, whereas DR resources are not typically available to provide primary frequency response or spinning reserve.

Finally, transmission solutions are well-positioned to provide essential reliability services. Flexible Alternating Current Transmission System (FACTS) devices are designed to enhance the system's controllability and increase power transfer capability, by enabling reactive power to be absorbed or injected into the grid as needed to maintain reliability. These include such technologies as Static VAR Compensators, Static Synchronous Compensators, advanced inverters and other technologies. Traditional AC transmission components and High Voltage Direct Current (HVDC) infrastructure – while not providing essential reliability services directly – assist in connecting generation and supportive transmission resources that can provide them to the location of need on the system.

2. *Flexibility*

Flexibility refers to the grid's ability to maintain balance between energy supply and customer demand. Distinct from the reliability value of frequency response or voltage control – which ensure grid stability and strength – flexibility ensures that there is sufficient capacity with the right capabilities to ramp up or down with fluctuations in net demand. These changes could be either a result of unexpected or cyclical increases in energy demand from customers, or changes in renewable resource availability. Key measures of flexibility include a resource's start time, ramp rate, energy availability duration, and its ability to cycle.

As its name implies, traditional baseload generation has not historically been well suited to provide grid flexibility; these plants are intended to run at relatively high output for long durations, and do not typically load follow or ramp in response to net demand changes. That said, as variable renewable adoption on the grid has increased, we have made and continue to make adjustments to these resources to make them more flexible. For example, we are beginning to implement flexible nuclear operations procedures that may allow us to ramp generation at these units up or down at least 10-15 percent, with day-ahead scheduling. Economic dispatch and seasonal operations for coal plants – both of which we are pursuing for our Minnesota coal plants – can also be considered a type of flexibility.[53]

Intermediate and peaking resources are some of the best positioned resources to provide flexibility to the system. Intermediate plants such as combined cycles (CC) are designed to load follow, within certain boundaries, in order to adjust to net load on the system over the course of a day. However, they are not typically designed to ramp quickly or start and stop more frequently; this is where peaking units such as combustion turbines (CT) fill a gap. CTs are intended to be able to meet evening load ramps, when demand typically increases, as well as start relatively quickly if the grid operator foresees a decline in variable renewable resources.

Variable renewables themselves can provide some flexibility services, if equipped with enabling technology – such as advanced inverters – or during periods of resource availability, with curtailment operations. That said, curtailment provisions in contracts and foregone clean generation typically make operating variable renewables in this manner less favorable. In other words, to keep the cleanest, lowest marginal cost resources operating as much as possible, grid operators have tended to use intermediate and peaking resources to fill-in around clean baseload and variable renewables.

Fast-burst balancing resources, such as DR and battery energy storage, can also meet a range of flexibility needs. Their ability to respond quickly to calls for load shifting needs can help address ramping and cycling needs, especially for relatively short duration events. As discussed above, battery energy storage can also help mitigate renewable resource variability when paired with wind or solar generation. As battery costs continue to decline, we would expect to see more paired resources combining

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[53] Our modeling reflects seasonal dispatch for King and Sherco 2 from Fall 2020-2023. After that time Sherco 2 retires and King continues to operate on an economic basis through its retirement date. Flexible nuclear operations is not yet integrated into our modeling as we work to better understand the parameters under which our units may perform this function. We discuss flexible nuclear operations further in Attachment A Section VIII.

the clean energy benefits of variable renewables with the balancing benefits of energy storage.

We note that transmission solutions also play an enabling role in energy flexibility, despite not providing it directly. For example, HVDC ties across broader regions increases a system's import and export capabilities and improves access to benefits from resource and geographic diversity. Particularly for variable renewables, increasing geographic diversity can reduce the effects of weather correlation; in other words, access to resources across broader areas makes it less likely that a localized renewable drought will result in energy shortfalls for that system's customers. That said, weather correlation can and does happen across broad regions, and thus transmission solutions are not alone sufficient to mitigate variability.

3. Energy Availability

Having sufficient energy available to meet demand across every hour of every day throughout the year is another fundamental element of reliability. The extent to which a given resource's capacity may be unavailable for unplanned reasons impacts the contribution of that resource to meeting our customers' energy needs. Planning and modeling must examine not only *average* availability, but also the extent to which underlying correlations with climatological or other factors result in higher unavailability or outage rates during peak load or other higher-risk periods. A resource's availability is driven by both fuel and equipment availability considerations, but we focus on fuel availability here.

The certainty of fuel availability – whether a plant will have fuel on site to produce electricity when needed – differs for different resource types. Traditional firm baseload resources are generally the most fuel-secure, as they have physical fuel resources on site. Coal and nuclear plants, for example, typically have a certain number of days-worth of on-site fuel storage either in fuel storage yards (for coal) or within the plant itself (nuclear fuel rods). Natural gas plants may have on-site storage, but, more typically, plant operators ensure fuel delivery through firm supply contracts. Firm contracts mitigate fuel availability issues, as long as the natural gas transmission and delivery system do not face unexpected operational challenges.

Other resource types face fuel availability limitations. Variable renewables are dependent on climatological conditions, which can be forecasted within certain margins of error, but these forecasts do not provide the same level of fuel security as a plant with physical fuel on-site or guaranteed via firm contracts. Further, plant operators are limited in their ability to control variable renewable fuel sources. Thus, other resources on the grid must be prepared to fill in gaps when they are not producing. At scale, this absence of on-demand fuel availability can create ramping challenges regardless of whether changes in availability were forecast.

Fast-burst resources can vary in their fuel availability, either based on state of charge at a given time (for battery energy storage) or customers' willingness to respond to calls to reduce their demand (DR); further, these resources are duration limited. Typical battery energy storage facilities using current technology can provide up to four hours of discharge at its given rating, if the battery started at a full state of charge. DR calls generally have duration and frequency parameters and are additionally subject to customer discretion. That said, battery storage holds particular promise for addressing some of the fuel availability challenges associated with variable renewables, as a battery can charge during periods of renewable overgeneration and discharge when the resource is unavailable.

4. *Black Start*

Finally, black start capability is a rarely needed – but essential – grid attribute. Black start capability refers to whether the grid has specialized resources that can "jumpstart" the grid from a partial or complete outage.[54] These resources require a secure fuel source, must be able to start without external electrical support from the grid and run unloaded for relatively long periods of time. They must be able to provide both real and reactive power, so that the transmission operator can use them to balance bringing incremental loads onto the system while providing energy to start other non-black start capable grid resources. We discuss our black start resources further in Attachment A Section VII.

There are few resource types well positioned to provide black start service. Black start units are typically firm traditional resources because, when equipped with certain controls, they are capable of meeting the necessary requirements discussed above. Variable renewable resources cannot provide this service because they do not have secure fuel sources and their power outputs are not easily controlled in order to balance with incremental load. While battery energy storage is theoretically capable of operating under these conditions, such units only have secure fuel sources insofar as they are charged at the time of a grid failure. Black start resources must be capable of running for longer periods of time than typical battery energy storage systems are configured to operate, especially in the event a subsequently-started generator trips

[54] Note that black start capabilities are distinct from system restoration more broadly. This section refers specifically to the ability of a generator to start from black, on demand.

back offline, and the process must be restarted; a rather common occurrence during a black start event. To reliably provide black start service, a battery would need to be capable of 24 hours or more of discharge, which is prohibitively expensive given current technology. We also note that the amount of battery capacity designated for black start service would likely not be able to participate in other commercial market opportunities – such as ancillary service markets – rather, would always have to maintain a full state of charge, per black start capable fuel security requirements. As a result, the cost of such a battery is not likely to be effectively mitigated by its opportunity to provide system services under normal operations.

B. Resource Attribute Evaluation in Resource Planning Models

The Company relies on planning models to determine the combination of resources that will best serve our system's needs, including their ability to meet energy, demand, and other grid attribute needs. For resource planning we have traditionally focused on Capacity Expansion (CE) modeling, which inherently includes some system dispatch analysis. We are now also conducting more robust, hourly chronological dispatch analysis via the EnCompass Production Cost Model (PCM) functionality. We note that these and the more detailed models used for network reliability and transmission planning, are intended to address system needs at different levels of granularity; thus, they are able to assess different resource attributes. Further, since we have just acquired the new EnCompass model, it is important to note that we are continuing to explore and test the best approaches and methodologies we can leverage to model our future system in the most realistic way possible. Our approaches may evolve in the future as we better understand the capabilities of the tool and/or learn of new novel approaches to power systems modeling as part of long-term resource planning. That said, we discuss these models' general capabilities – and limitations – with respect to incorporating resource attribute considerations into resource planning modeling further below.

Figure VI-2: Planning Model Capabilities

	Capacity Expansion	Production Cost	Network Reliability
Objective	▪ Solve for a least cost-expansion plan for medium-long term generation portfolio	▪ Simulates hourly chronological dispatch and system operations for a CE-defined portfolio	▪ Test essential reliability service conditions of a defined portfolio
Functionality	▪ High-level system simulation to determine capacity adequacy needs and least-cost portfolios, given assumptions about future demand, fuel and technology costs, and policy parameters ▪ Provides annual generation portfolios and associated costs, carbon emissions estimates	▪ Uses outputs of capacity expansion to conduct hourly chronological system dispatch simulations ▪ Evaluates unserved energy/loss of load; zonal or nodal marginal pricing; some ancillary services	▪ Analyzes transmission network to simulate essential reliability service conditions under contingencies, uncover potential failures ▪ Includes power flow, system dynamics modeling; typically run by ISOs/RTOs
Time granularity	▪ Annual, based on representative days or weeks	▪ Generally hourly, some capable of sub-hourly assessment	▪ Minute-by-minute, or shorter durations
Attributes assessed	▪ Capacity adequacy, some flexibility	▪ Capacity adequacy, energy adequacy, flexibility (e.g. ramp rates)	▪ Essential reliability services, such as frequency response and transient stability
Examples	▪ **Strategist, EnCompass,** RESOLVE, Aurora	▪ **EnCompass**, PLEXOS, RECAP, PROMOD	▪ Positive Sequence Load Flow, Power System Simulator for Engineering

1. *Capacity Expansion Modeling*

Historically, we have used CE models, such as Strategist, to evaluate least-cost resource portfolios to meet a forecast of long-range customer needs. It does this by evaluating energy and capacity needs in each year and selecting least-cost generic resource options that fill those deficiencies. In the course of CE modeling, Strategist performs simplified dispatch analyses using load duration curves that examine a subset of representative hours across the year. In our analysis specifically, Strategist takes 2,014 hours of load for each year – one week from each month– and arranges the load from highest to lowest, creating a load duration curve. It then simulates a resource portfolio dispatch that ensures that energy is procured to serve the annual load, which is later adjusted to account for market purchase and sales opportunities.

Capacity expansion models like Strategist are valuable tools for resource planning, but they are inherently limited in the breadth of resource attributes they can assess. Strategist makes resource decisions based on load duration curves, which do not fully capture the challenges of balancing large quantities of renewable energy that produce hour by hour fluctuation in system energy needs, and its dispatch modeling functionality is simplified to representative weeks. Therefore, it does not provide complete information about a given portfolio's ability to meet flexibility or other essential reliability service attributes. In the past, when significant portions of customer needs were supplied by baseload resources or intermediate and peaking resources that could be more easily controlled to follow load, these aspects of a resource portfolio were less prominent considerations; traditional resources inherently provided all of those things.

However, as variable renewable resources have become a larger proportion of our total resource portfolio – both because of increased renewable adoption and retirement of legacy thermal resources – some CE models' annual capacity adequacy assessments and simplified load duration curve dispatch approaches are no longer necessarily good tools to fully assess and ensure energy availability in every hour across the year. We note that these are limitations associated both with modeling capabilities and resource adequacy (RA) constructs, the latter of which we discuss further below.

2. *Production Cost Modeling*

Production cost modeling represents the next step in understanding intraday availability and flexibility need on the systems. Production cost models use the outputs of capacity expansion modeling (i.e. the preferred generation portfolio expansion plans) to perform hourly chronological dispatch simulations that provide better insight into a system's intraday reliability, availability and flexibility needs. For example, assessing hourly profiles for resources and load helps planners identify whether a proposed portfolio could result in hours with unserved energy or a high reliance on market energy. It can also show the extent to which a system's net load changes across hours, indicating whether the proposed system can accommodate ramping needs.

As described in Section II of this Supplement, we used EnCompass modeling both to conduct capacity expansion modeling and the more detailed hourly production cost modeling, to better assess our scenarios' cost impacts, energy adequacy and flexibility. First, we use the EnCompass capacity expansion functionality to define capacity expansion plans for each baseload scenario. For capacity expansion, we used EnCompass capabilities to simplify hourly system inputs to a sampling of representative days and on- or off-peak time periods, in order to improve model performance and runtime efficiency. However, after the expansion plans were defined, we used the model's full 8,760-hour chronological modeling capabilities to run analyses testing cost for each year from 2020 to 2045. We have also tested individual portfolio results for reliability aspects in 2034, which is the last year of our planning period.

In order to move from a more simplified load duration curve analysis into EnCompass hourly dispatch modeling, we used hourly load and generation profiles for each year of the forecast and incorporated Typical Meteorological Year (TMY) shapes for renewable generation profiles. The TMY shapes provide indications of hourly renewable generation levels we may expect to see over the course of a year with average weather conditions. While using historical weather proxies to estimate future load and renewable availability is a fairly common modeling practice, it is limited in that it does not effectively capture extreme weather events that our system may encounter in a given year – such as an extreme heat wave in the summer, or a polar vortex condition in the winter. That said, historical proxies provide helpful information for examining the present value cost, emissions profiles, and reliability of our capacity expansion portfolios under "average" conditions. This analysis also allows us to examine whether the portfolio defined by capacity expansion modeling would result in any periods of unserved energy, or tight reserve margins, or increasing ramping needs in given times during an average year. If CE modeling is sufficiently covering energy and capacity needs across an average year, however, we would not expect this phase of analysis to uncover any reliability challenges.

After examining portfolio performance based on a typical year, however, we also want to ensure that our system remains reliable under more extreme conditions. The reliability analyses we conducted on our Supplement Preferred Plan (Scenario 9) and selected Scenario 9 sensitivities examine their performance under historical meteorological conditions from a previous year, in this case 2019. To assess reliability risks, we examined how these sensitivities perform on metrics such as duration and quantity of net internal capacity shortfalls, maximum import needs, maximum ramping needs, and standard industry metrics. Our preliminary analyses show that there is reliability risk associated with some sensitivity portfolios under stress conditions, and this risk increases in sensitivity portfolios that include higher ratios of variable generation to peak load. These findings are detailed further in Section II of this filing and Attachment A Section XII. That said, we continue to examine EnCompass capabilities related to reliability analysis and will continue to develop new insights as we work more with the tool.

3. *Intersection of Resource Planning and Transmission Planning*

This hourly chronological modeling process represents a necessary incremental step forward in understanding how our system will operate in future with more variable renewables. In particular, we note that, when modeling our Resource Plan with EnCompass and adjusting capacity accreditation for updated MISO assumptions, we no longer directly imposed any *ex ante* Reliability Requirement, like we did in our initial July 2019 Resource Plan. EnCompass better reflects actual market conditions, and therefore selected resources that provide sufficient energy availability and flexibility attributes given load and renewable shape assumptions, as compared to the results from Strategist modeling.

That said, hourly production cost models like EnCompass also have limitations. While its hourly granularity is an improvement over Strategist's capabilities, there are aspects of system flexibility – alongside most essential reliability services – that occur on a sub-hourly basis. An hourly model may not capture all the value a fast-burst resource like battery energy storage can provide, such as very fast response to frequency drops or ramping needs, for example. Further, hourly resource planning modeling cannot replace the more detailed power flow modeling and dynamic system modeling that occurs in transmission system planning processes. These models consider an additional component – a generator's location – that is not studied in the course of typical resource planning. Transmission planning models also examine grid reliability and stability impacts of specific resource additions or subtractions at very granular timescales. Ultimately, capacity expansion, production cost, and transmission planning modeling are related but separate practices with distinct objectives

Additionally, most models, including EnCompass, have a "perfect foresight bias," wherein the model perfectly solves for factors that are, in reality, subject to a degree of randomness and variability. These include future load and load profiles, renewable generation, and unit forced outages. The system dispatcher does not have this perfect foresight, and prudently incorporates a level of risk aversion into actual operations (i.e. having extra resources committed and online) that the models do not capture.

4. *Resource Adequacy Constructs and Effects on Resource Planning*

As noted above, increasing levels of renewable adoption and baseload retirements mean that modeling and evaluating future resource plans using only CE modeling only is no longer sufficient to ensure energy adequacy in every hour of every day. This challenge is attributable in part to modeling capabilities, as discussed above, but also outmoded RA constructs that do not effectively capture variability. Our existing

RA requirements only provide values for the year ahead, based on a year's peak demand hour, rather than providing forward looking or seasonally adjusted values. When renewable resources' share of the total system is relatively low, it is reasonable to assume the other resources – which often have been firm traditional resources or the market – will be able to meet customers' needs. In other words, when most generation is dispatchable, these limitations represent a low risk that a portfolio could be capacity sufficient but result in unmet energy or flexibility needs.

As we add more variable renewables to our system going forward, capacity adequacy and energy adequacy begin to decouple, increasing the risk that a portfolio could appear capacity sufficient – given existing RA constructs – but result in flexibility or energy availability shortfalls. We have partially mitigated this effect in our Supplement by using MISO MTEP forward-looking RA values for solar capacity, rather than using the most recent year-ahead RA values, which helps account for solar's natural marginal declining ELCC as adoption increases.[55] However, variable renewables are also weather dependent, and an annual peak measure still does not indicate these resources' contributions to ensuring our system has sufficient energy to serve customers in all hours of the year. As a result, normal monthly or seasonal variation in renewable availability is not perfectly reflected in CE modeling alone; it is apparent that variable renewables often do not produce at these levels throughout the year and are sometimes unavailable for multiple days at a time. Recent examples of multi-day unavailability in the MISO area and our system, respectively, are depicted in the Figures below.

[55] We note that MISO is further examining declining ELCC for variable resources as adoption increases, in its *Renewable Integration Impact Assessment* work as well. As renewable penetration on the system increases, risk of load loss shifts and each incremental renewable resource is less able to mitigate that risk. *See* https://cdn.misoenergy.org/20191114%20RIIA%20Workshop%20Item%203%20Resource%20Adequacy400382.pdf. The California ISO already requires load serving entities to assess monthly ELCC variations in their RA procurement practices and assumes declining marginal ELCC for solar in their Integrated Resource Planning processes. California's approach to variable renewable resource capacity accreditation is discussed further below, in Section 3.

PUBLIC DOCUMENT -
NOT PUBLIC DATA HAS BEEN EXCISED

Figure VI-3: MISO Observed Wind Output Relative to Average Available Capacity[56] – December 2, 2019 to February 23, 2020

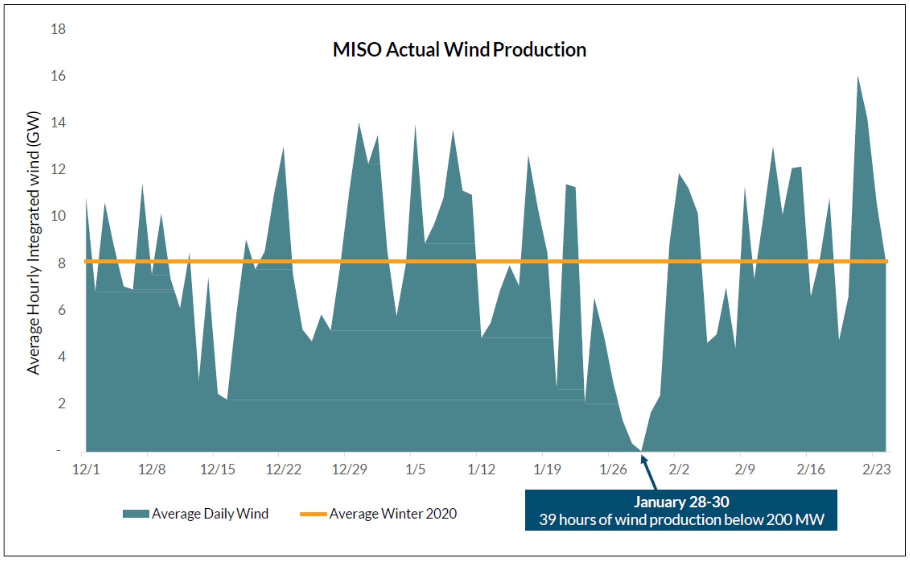
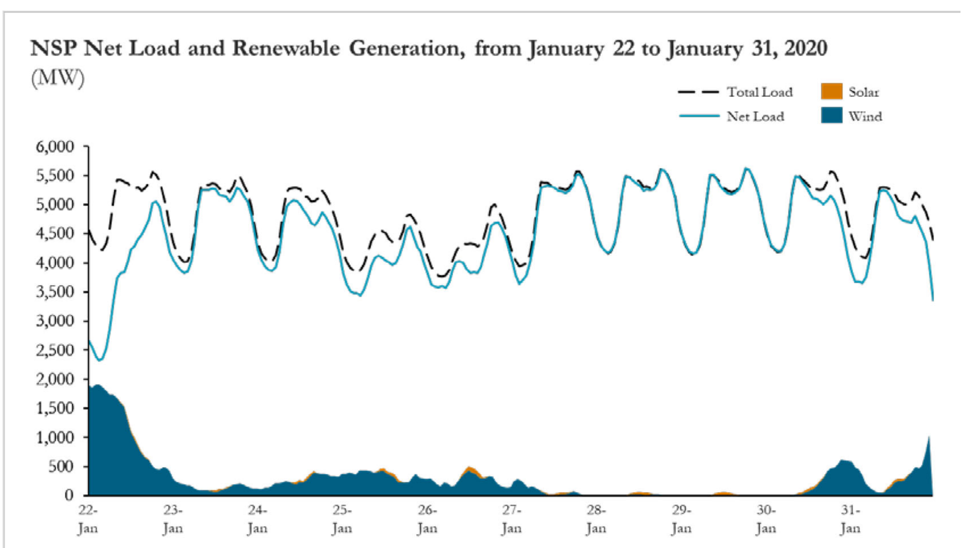


Figure VI-4: Xcel Energy Upper Midwest Net Load During a Multi-Day Renewable Drought – January 22-31, 2020



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[56] *See* "MISO Operations Report," (March 24, 2020) at 7. Available at: https://cdn.misoenergy.org/20200324%20Markets%20Committee%20of%20the%20BOD%20Item%2005%20MISO%20Operations%20Report437854.pdf

Renewable drought conditions such as those illustrated above leave a large gap between customer demand and variable renewable resources' availability to serve it in a given hour. We note that, in the NSP system example, customers did not experience system-wide disruption to their service during this time, in part because we have sufficient responsive capacity on the system to accommodate these levels of net demand over sustained periods. We can also rely on the MISO market to fill some of these needs; however, the extent to which we rely on the market to provide energy at the time we need it introduces a risk tradeoff that must be considered.

For example, there is a technical import limit of approximately 2,300 MW into our system from the broader MISO area, although the available import/export capacity varies – sometimes significantly – by hour. [57] To the extent we rely on market purchases and import capabilities, they are considered non-firm and as such, are not dedicated and guaranteed to serve our system at any time needed. And our ability to purchase up to the current 2,300 MW import limit depends on timely available excess to generation from neighboring utilities or merchant generators in MISO. While a market that spans a broader geographic area can improve variable renewables' overall contribution to load, there may also be weather correlation and associated price risks to manage within or between adjacent market zones. In other words, our neighboring utilities and merchant generators may not always have sufficient excess energy or capacity to sell to meet an internal shortfall on our system, especially if that shortfall results from broader regional weather events.[58]

Currently, some of this risk can be mitigated by improved forecasting capabilities and planning for other generators to ramp up in response. However, were our shortfall to exceed the available import capability at a given time, and we did not have sufficient firm capacity available for us to deploy to make-up for that shortfall, customers would experience a load shedding event regardless of whether the shortfall were forecasted in advance. Thus, potential renewable drought conditions will introduce increasing risks in maintaining reliability on the grid, as variable resources become a higher and higher share of our energy mix and legacy thermal generation retires. Our planning approaches and constructs also will need to adapt in order to better capture these conditions and the resulting hourly variation in net demand and energy availability.

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[57] We note that our current production cost modeling process assumes the NSP system's full import capability is always available and cannot dynamically adjust to modeled market conditions in the remainder of MISO. We model market interactions with the remainder of MISO using forward curve market price assumptions at import nodes, rather than modeling dynamic market interactions. As a result, our modeling does not capture potential constraints on our import capability that may arise from correlations in increased market reliance amongst other market participants.
[58] If reduced renewable availability, for example, were widespread throughout upper MISO and adjoining Southwest Power Pool regions – which past operational data has indicated at times – the price of procuring from the market could increase substantially for several hours at a time.

Hourly chronological dispatch modeling, such as the PCM functionality in EnCompass, gives us additional insight into these intra-day and inter-day hourly conditions. For example, examining our system's energy and capacity availability over 8,760 hours allows us to evaluate whether there are time periods in which our system risks capacity shortfalls, periods of unserved energy, or significant ramping events. Increasing prevalence, or long duration periods, of market reliance is a financial and reliability risk to customers and may also indicate that the resources on our system in that analysis year would be insufficient to meet customer needs, if our import capability were constrained. In particular, as the largest member of MISO Zone 1, our import needs may correlate with other Zone 1 members' needs and therefore, the full import capabilities for the Zone may not be available to only our system – creating a shortfall for our customers.

All said, the challenges associated with a system transitioning to higher levels of variable renewable dependence make it increasingly important that MISO RA constructs appropriately reflect variable renewables' potential impacts to a grid. Thus, one goal inherent in our resource plan modeling is to maintain enough responsive capacity to hedge customers' risk of being exposed to drastic price spikes or load shedding events, when ramping events or long duration renewable droughts occur.

C. Emerging Methods of Evaluating Resource Attributes

As we continue to develop our modeling processes to more adequately reflect system needs through our transition to a cleaner grid, new resource assessment methods in both planning and procurement processes are emerging.[59] These include flexibility-specific RA, more granular or forward-looking ELCC evaluations, using risk metrics – such as Loss of Load Probability (LOLP) in determining reliability surety instead of a static reserve margin or ELCC – and even factoring resource attribute considerations into the modeled costs of different energy technologies. The Company's modeling will continue to evolve to best reflect system conditions and MISO guidelines, and we may also examine using additional approaches to examine the adequacy of our portfolio's resource attributes in the future.

[59] As discussed in our initial filing and noted herein, MISO's *Resource Availability and Need* and *Renewable Integration Impact Assessment* efforts are a step toward examining the potential for new RA constructs and resource attribute analyses in our region. In our initial filing we discuss these initiatives in Chapter II. Planning Landscape and Appendix J2 – Reliability Requirement.

1. *Flexibility-Specific Resource Adequacy Constructs*

Some utilities and markets across the country explicitly value flexibility in their resource planning or RA processes. For example, Public Service Company of New Mexico (PNM) has implemented a method of examining potential shortfalls in flexibility in its production cost modeling. The traditional method of examining LOLE measures capacity adequacy at peak conditions, meaning that it evaluates the probability that capacity available on the system would be insufficient to meet the day's peak needs. PNM worked with Astrape Consulting to develop and evaluate a modified measure called $LOLE_{Flex}$, which examines potential load shedding events resulting from insufficient system ramping capability. It evaluates these events in a PCM software called SERVM, both on an inter- and intra-hour basis.

The system ramping metric is instructive as variable renewables increase on the system, because even predictable ramping events can result in load shedding if there are not enough flexible resources on the system to respond. This is especially the case in areas where substantial solar development exacerbates the trajectory of evening ramping needs, as net demand can increase rapidly over a short period of time when solar output declines and customer demand increases simultaneously. Where the model finds potential $LOLE_{Flex}$ events, it includes the cost of unserved energy in its production cost totals; planners can use this information to evaluate the opportunity cost of mitigation, such as changing operational procedures like increasing market operating reserves or adding flexible resources to mitigate loss of load risk during extreme ramping events.[60]

The California Public Utility Commission (CPUC) instituted a flexibility-specific RA metric in load serving entities' annual RA procurement processes in 2013.[61] Under this construct, the California Independent System Operator (CAISO) evaluates expected flexibility needs for the year ahead based on forecasted net load ramping need analyses, and the CPUC subsequently sets load serving entities' flexible RA procurement requirements.[62] Flex RA requirements are especially essential to the

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[60] *See* Astrape Consulting. "PNM Preliminary Reliability Analysis." April 18, 2017 at 26. Available at: https://www.pnm.com/documents/396023/3306887/04182017-irp-mtg-reliability/66b6bdc0-d9d4-4f72-b1dc-076d8c5c74c2

[61] *See* D.13-06-024 *Decision Adopting Local Procurement Obligations for 2014, A Flexible Capacity Framework, and Further Refining the Resource Adequacy Program* (June 27, 2013).

[62] Note that CPUC-jurisdictional load serving entities generally do not own generation assets (with some exceptions) and the CPUC oversees reliability procurement. We note that the CPUC recently instituted a central procurement construct, assigning two large utilities to conduct local reliability procurement on behalf of all jurisdictional load-serving entities, in order to ensure multi-year local RA requirements are cost-effectively achieved. *See* Docket No. R.17-09-020. "CPUC Adopts Central Procurement Framework for Local Resource Adequacy." Available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M340/K048/340048112.PDF

California system because of the "duck-curve" phenomenon, where high mid-day solar generation can cause steep three-hour ramping needs, sometimes exceeding 10,000 MW in the spring when daytime load is relatively low.

2. ELCC Values in Procurement and Planning

Several utilities in the United States now utilize ELCC values that change over time to better reflect how increased adoption will affect variable or use-limited resources' capacity value.[63] For planning, utilities may move from using current ELCC values across the planning period to instead, estimating forward-looking measures, in order to better reflect how additional build-out will affect the overall capacity value of their portfolios. For near-term procurement constructs, some jurisdictions use ELCC values that reflect monthly or seasonal differences in expected resource availability and production capabilities. The CPUC provides examples of both of these developments, but other utilities are also exploring opportunities to improve reliability planning as their clean energy transitions progress.

In its RA procurement requirements, the CPUC has begun to use monthly average ELCC values to determine variable renewable resources' qualifying capacity. The CPUC asserts that using a single annual peak value for this purpose would be inappropriate, stating:

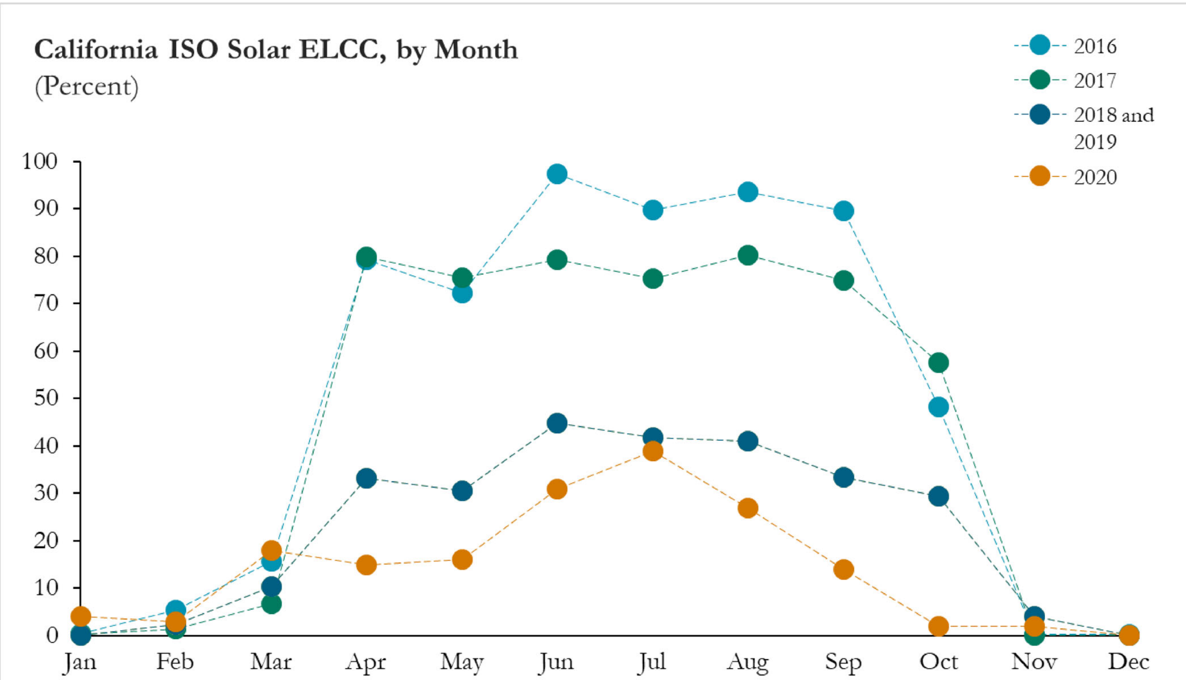
> ELCC values based on a study of just the peak months are not sufficient for this purpose, due to the highly variable ELCC value of these resources depending particularly in the case of solar and wind, on monthly patterns of electric demand and weather patterns."[64]

We note that the CPUC's assigned monthly solar ELCC values have also declined significantly over time, as solar has increased as a share of total capacity in the broader system. We portray the change in monthly ELCC values since 2016 in the below Figure.

[63] As indicated in Section II, these include DTE Energy, Indianapolis Power & Light, Dominion Virginia, Vectren and others.

[64] *See* D.19-06-026 *Decision Adopting Local Capacity Obligations for 2020-2022, Adopting Flexible Capacity Obligations for 2020, and Refining the Resource Adequacy Program.* (June 27,2019) at Appendix A1.

Figure VI-5: California ISO Solar ELCC, by Month[65]



The CPUC has further implemented an expectation of forward-looking ELCC into its resource planning process. In guidance for the current resource planning cycle for CPUC-jurisdictional load serving entities conducting their own production cost modeling, CPUC staff provided guidance that includes forward-looking average annual ELCC assumptions. These values are based on state-level reference plans that achieve specific greenhouse gas emissions thresholds.[66]

3. Value Adjusted Levelized Cost of Energy

Another approach to incorporating resource attributes into planning involves valuing capacity, energy, and flexibility directly, in a modified levelized cost of energy (LCOE) metric. This approach recognizes that pure levelized cost calculations do not fully capture all the grid attributes various resource types can provide, but rather than

[65] Note: Assigned ELCC values for 2019 were the same as 2018. Data available at: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

[66] *See* Docket No. R.16-02-007. "ELCC assumptions used within the Resource Data Template," (May 12, 2020). Available at: ftp://ftp.cpuc.ca.gov/energy/modeling/ELCC_assumptions_used_within_the_Resource_Data_Template.xlsx

modeling attribute values through separate processes, they could be captured in a common valuation metric that would allow better comparison across resource types.

The International Energy Agency (IEA) has adopted this approach in their latest World Energy Outlook (WEO). The WEO is an annual report that attempts to project global energy demand and the capacity expansion expected to meet these needs under a given set of market and policy assumptions. IEA developed a metric called the Value Adjusted Levelized Cost of Energy (VALCOE) that combines each resource type's pure levelized cost with estimated value attributes for capacity, energy, and flexibility. The IEA describes the need for a value-adjusted cost comparison approach in the following way:

> While LCOE has the advantage of compressing all the direct technology costs into a single metric which is easy to understand, it nevertheless has significant shortcomings: it lacks representation of value or indirect costs to the system and it is particularly poor for comparing technologies that operate differently (e.g. variable renewables and dispatchable technologies). VALCOE enables comparisons that take account of both cost and value to be made between variable renewables and dispatchable thermal technologies.[67]

We are not aware of any utilities or regulatory agencies in the United States that use this approach currently. However, we expect value-adjusted methods will be considered as the industry continues to transition away from traditional thermal sources and incorporates increasing levels of variable renewables and fast-burst resources.

[67] *See* IEA. "World Energy Model Documentation," 2019 Version, at 44.

VII. BLACK START

Black start resources are a critical component of system resilience and long-term reliability. In our initial filing, we noted that planned system retirements over the next several years will affect our current black start plans, and that we were analyzing options for the best path forward. While we continue that work, we believed it was important to include placeholder capacity and costs for a potential future black start solution in our supplemental modeling. To be clear, this modeling proxy does not represent our proposal; rather including placeholder capacity allows us to show how our eventual proposed black start resources may fit into and impact our overall Preferred Plan. Below we briefly discuss what black start is, why it essential to maintain black start resources on our system and provide further discussion regarding how we have represented black start resources in our modeling.

A. Black Start Fundamentals

Black start resources and standards surrounding restoration plans have been an essential part of utility reliability planning for several decades.[68] These resources are comprised of the generating units and transmission infrastructure the Company must maintain in order to restart the system in the event of a widespread or catastrophic grid outage. While rare, bulk electric system blackouts require transmission and generation operators across an affected area to work together, in order to carefully and incrementally balance electricity generation as it is restored alongside customer load. This helps to ensure the broader system regains and maintains stability as operators restore individual grid "islands" and reconnect these islands until the full grid is operational again.

More specifically, the North American Energy Reliability Corporation (NERC) defines sets of standards for both Transmission and Generation Operators regarding the characteristics of viable restoration plans and black start generation resources – and rules governing these entities' interaction with the Reliability Coordinator in a given region – which they outline in Emergency Operating Procedure (EOP) 005-3. For the NSP system, we are both the Generation and Transmission Operator, and MISO is the Reliability Coordinator. Under this procedure, each Transmission Operator must maintain a restoration plan, in cooperation with the regional Reliability Coordinator, that meets several specific requirements. Required components include:

[68] NERC, for example, has had black start restoration plan guidelines since at least 1993.

- identifying black start resources and their characteristics to be used to restart the system in the event of a widespread outage;
- the process of restoring loads required to balance and stabilize generation resources;
- identifying a cranking path between the black start resources and subsequent units incrementally, to restore other generation units on the system;[69]
- and procedures to reconnect neighboring grid areas when they are stable, in order to restore the broader interconnected grid.[70]

Each Generation Operator providing black start service must ensure its black start-designated units can start and run unloaded – without external support from the system – and meet the Transmission Operator's restoration plan requirements for real and reactive power. MISO further provides a list of requirements pertaining to black start generating units in their Business Practice Manual 022. According to MISO, black start-capable generation resources in its area must have the following characteristics:

- capability of operating at zero load for a time period as required to accomplish the Transmission Operator's Restoration Plan, and to close on a dead bus;
- sufficient reactive reserve capability to energize the transmission system to supply the facility with restoration power;
- adequate inventory of fuel supply to accomplish the Restoration Plan;
- be periodically tested to ensure availability and capability to supply useful energy (e.g. meeting sufficient quantity of energy, and frequency and voltage requirements) to the station bus in an acceptable time period, as defined by the Transmission Operator and regional reliability entity.[71]

Given these special requirements, not every generation unit on the grid is configured to provide black start services; units require special controls to be able to run unloaded and support transmission frequency control, so the plants are often

[69] We note that nuclear units have specific station power restoration requirements to maintain critical controls, even though nuclear units are some of the last to be brought back fully online to serve customer load. Our NERC operating agreements for Monticello and Prairie Island require station power restoration within four hours of a grid outage.
[70] *See* NERC "Reliability Standards for the Bulk Electric Systems of North America," EOP 005-3. Updated January 2020. Available at: https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States
[71] *See* MISO "Blackstart Service Business Practice Manual," BPM-022-r10. Effective September 2018. Available at: https://www.misoenergy.org/legal/business-practice-manuals/

specifically designed to be black-start-capable when first constructed. However, black-start-capable units can and do run during normal operations, often providing firm and dispatchable peaking capacity to the grid.

In NSP's restoration plans, the description of black start resources above refers to what we have termed "Initial Units." Our Initial Units have a secure fuel supply, can help jumpstart our system with no outside grid support and can reenergize part of the transmission system, and run for up to a full day on little to no load. There are also second-step "Target Units" that receive station power from the Initial Units in order to start, and that subsequently provide additional energy and grid stability necessary to restart and stabilize the remainder of the system. We have both Target and Initial Units in each the NSP-Minnesota and NSP-Wisconsin systems, as maintaining distinct black start plans for both operating companies facilitates faster restoration for our broader Upper Midwest system. Both types of units can provide valuable energy and capacity during normal operations as well.

Restoration in a careful, but timely, manner after a catastrophic event is essential to the health and wellbeing of our customers and the broader economy. Long duration outages spread over a broad area can mean millions of dollars of lost economic activity[72] and can be associated with serious negative health effects for certain customers as well. Timely and robust restoration on our system is also essential to our neighboring utility service areas, as interconnected systems often depend on each other to complete their own restoration processes.

B. Resource Modeling and Black Start Units

As noted above, black start events are high impact but rare. As such, our resource plan modeling does not capture the full value these units provide our system. However, because both Initial and Target Units can also provide the grid with energy and capacity during normal operations, they are included in our capacity expansion and production cost modeling processes. Today, our existing Initial Units and Target Units in both Minnesota and Wisconsin are part of the over 3,000 MW of firm coal and gas capacity slated for retirement or contract expiration within the planning period; this is even before including our proposed Preferred Plan retirements for King

[72] For example, studies suggest that the last widespread regional grid outage in the Eastern Interconnection – in August 2003 – affected 50 million people in the US and Canada and had negative economic impacts in the range of $4.5-8.2 billion dollars. *See* Electricity Consumers Resource Council, "Economic Impacts of the August 2003 Blackout," (February 2004) at 1. Available at: https://elcon.org/wp-content/uploads/Economic20Impacts20of20August20200320Blackout1.pdf

and Sherco 3, which would add another 1,000 MW to that total. Many of these retiring units will be over 40 years old at their expected retirement dates.

As noted in our previous Resource Plan filings[73] the Sherco site is currently a critical piece of our Minnesota black start plans. Sherco Units 1 and 2 currently serve as our Target Units and as they retire in 2026 and 2023 respectively, we will need to develop alternative restoration path and Target Unit options. One key benefit of the new Sherco CC is that it replaces many of the grid attributes our coal units currently provide, but with more flexible capabilities and substantially less carbon emitted. We expect that the plant would play an important role in the event of a widespread grid outage, providing a large, stable generating source that we build upon to restore larger and larger portions of the grid. Further, it can enable the site to continue supporting restoration and maintenance of auxiliary power at our nuclear units, until they can be brought fully online later in the restoration process. That said, we continue to evaluate Target Unit options as part of our black start planning processes.

As discussed previously, Target Units cannot start from a fully de-energized grid on their own. We need specially-sized and equipped Initial Units to jumpstart the restoration process, after which the larger firm dispatchable Target Units can be started and balanced with increments of customer load. After the system achieves stability with those resources, variable renewable resources and finally the nuclear units can be added, completing the restoration process; a process which, in total, spans several days. In addition to the ability to start without outside support, the unique attributes of our Initial Units align with NERC requirements, as they have a secure fuel supply and the capability to run as an island with no balancing load. Proximity to load centers is also a benefit, given small increments of customer load are important building blocks to restoring the full system.

Our full black start alternatives analysis is still underway, and we are working to identify various potential options for black start-critical resources – in both our Minnesota and Wisconsin systems – going forward. However, we do know that that if all planned resource retirements are pursued, and none of the capacity is replaced with units that can provide similar grid attributes, we would not have sufficient black-start-capable resources available internal to our integrated Upper Midwest system to fulfill our complete restoration plans. We would then be forced to rely on neighboring utilities to support our restoration, which could not only result in extended outages for our customers, but also – as a result of interdependencies between systems – make restoration of the broader regional grid a longer and more challenging process. Thus,

[73] Both the 2016-2030 Resource Plan (Docket No. E002/RP-15-21) and our Initial filing in the instant docket.

we have represented this essential resource capability in our Supplement Preferred Plan via a modeling proxy that **[PROTECTED DATA BEGINS…**

…PROTECTED DATA ENDS]. In total, these resources provide approximately 430 MW of accredited[74] black-start capable peaking capacity to the NSP System. Our modeling also includes cost assumptions that **[PROTECTED DATA BEGINS…**

…PROTECTED DATA ENDS]. In total, this placeholder results in approximately **[PROTECTED DATA BEGINS…**
…PROTECTED DATA ENDS] added to all scenarios in order appropriately model necessary black start resources.

We emphasize, however, that that this proxy approach is only an interim placeholder and does not constitute a proposal for resources required for our long-term black start plan. We continue to examine a broad range of alternatives that will provide the needed system resilience and reliability benefits, long-term cost-effectiveness, and consider and balance environmental impacts; these alternatives include building new units, retrofitting existing units, and energy storage technology options.

[74] Note that this corresponds to approximately 620 MW of max capacity.

VIII. NUCLEAR UPDATE

As discussed in the Supplement Preferred Plan, carbon-free nuclear generation continues to be a cornerstone of our plan to serve customers with increasingly clean energy. In Appendix K of our initial filing we discussed how our nuclear fleet performance has become even more cost effective, while achieving stringent safety performance targets in recent years. We also discussed in more detail the role we envision nuclear power playing in our Supplement Preferred Plan going forward, including the proposed Monticello life extension and continued operation of Prairie Island 1 and 2 at least through their existing license lives.

Since last July, we have completed another year of strong performance at our units, achieving high capacity factors at low operational costs while maintaining high standards of safety. We safely completed two re-fueling outages while ensuring that the units could rapidly and safely return to operations and continue serving our customers with reliable carbon-free generation. We also continue to innovate, pressing ahead with plans to operate our units flexibly, to be more responsive to the availability of variable generation. Further positioning our nuclear fleet to be an essential piece of the carbon reduction story going forward, we will soon kick off a new demonstration project in partnership with Idaho National Laboratory (INL) and the U.S. Department of Energy (DOE) to examine the economic feasibility of using low-cost nuclear energy to produce clean hydrogen that can be burned for energy later, as a manner of time-shifting carbon-free generation. Our continued focus on operational excellence, alongside innovative new applications, demonstrates the value of our nuclear fleet beyond the standard baseload clean generation that have made these plants a key part of our energy mix for decades.

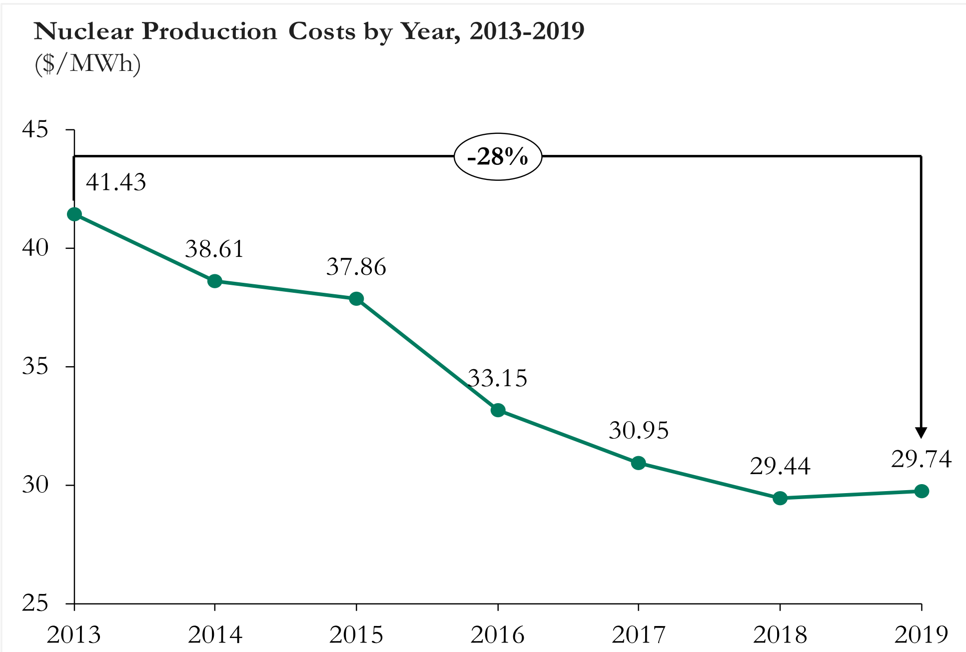
Our updated capacity expansion modeling continues to validate that view, as it shows that extending nuclear units results in a lower cost future generation portfolio than our Reference Case, in which they are taken offline when their current licenses expire in the early 2030's. The continued operation of our nuclear fleet is critical to the Company's achievement of our carbon reduction goals, including reducing carbon emissions by 80 percent from 2005 levels by 2030. Therefore, as part of our Supplement Preferred Plan, we continue to ask the Commission to approve a five-year action plan that includes starting to work on a Supplemental License Renewal (SLR) application for Monticello with the Nuclear Regulatory Commission (NRC). We also continue to acknowledge that, although several less expensive scenarios include a Prairie Island extension as well, the Company is still working with the surrounding community and proposes to revisit the potential for a Prairie Island license extension in the future.

A. Nuclear Fleet Performance

Our nuclear fleet continues to perform exceptionally well, in keeping with our efforts to reduce costs while enhancing operations and safety in recent years. It produced over 14.3 million megawatt hours (MWh) of electricity in 2019 – approximately 30 percent of energy generated by our entire generation fleet in 2019 – which is the second highest generation record since the nuclear fleet began operating. This performance resulted in a nuclear fleet-wide capacity factor of over 92.6 percent. Further, we achieved these above average results while safely completing two planned refueling outages. The refueling outage at Prairie Island Unit 2 was conducted without any reportable events in only 23 days, which is top quartile performance in the industry and the second shortest outage in the history of the unit. We also refueled the Monticello unit in in 30.5 days between April and May 2020.

We achieved these successful operating results while continuing to maintain safety and affordability, through operational excellence. Our fleet achieved its second year in a row of production costs below $30/MWh, which represents a nearly 30 percent decline from 2013 as shown in Figure VIII-1 below. We have reduced our operations and maintenance costs relative to 2018 by nearly $7 million, which represents a more than 2 percent improvement compared to 2018 results and marks the fourth straight year of declining O&M in our nuclear operations. We have achieved these operational savings while continuing to prioritize safety. Both the Monticello and Prairie Island plants have maintained high levels of safety performance, achieving top marks on the industry's rigorous safety evaluations. In fact, our nuclear fleet was recognized as one of the highest performing fleets in the country according to our nuclear industry peer group.

Figure VIII-1: Historical Xcel Energy Nuclear Fleet Production Cost



B. Operational Innovation Updates

The Company's nuclear fleet has been an important source of steady and stable clean baseload generation for several decades. Historically, baseload resources have not been expected to ramp up or down in response to changes in other resources on the system; instead, other intermediate or peaking resources have been adjusted as needed. However, as the fuel mix in our system (and the industry broadly) changes, we are preparing for a future in which our nuclear units may need to achieve more flexible operations and provide for different use cases in order accommodate higher levels of variable renewables on the grid. To this end, we are working on two specific initiatives: first, making our fleet more responsive to expected changes in net load with flexible operations; and second, an innovative pilot project with a federal laboratory to examine nuclear resources' potential role in producing clean hydrogen.

1. *Flexible Operations*

In our initial filing, we discussed a flexible operations strategy that allows our nuclear facilities to reduce power output when wind or solar resources are providing increasingly large amounts of energy relative to customer demand. At these times, the net load our other generating resources need to serve may decline significantly, such that it would even be economically beneficial to run our baseload resources at lower output. In our Upper Midwest system, we already observe some low pricing periods in times of high wind generation, and our Supplement Preferred Plan includes a significant buildout of additional variable renewables. Thus, making our nuclear fleet responsive and able to ramp down during periods of high congestion and low pricing is beneficial to our customers.

Operationally, this means we needed to evaluate our fleet's technical capability to maneuver units from full output to a level of reduced output, and then participate in the MISO market in accordance with this capability. In the past, our nuclear plants were generally offered into the regional power market as "must-run" resources that did not respond to expected inter-day fluctuations in net load. However, in order to accommodate more variable renewables on the grid, we have worked to develop operational strategies that allow us to offer the plants into the MISO Day-Ahead market on an economic basis, allowing for MISO to schedule a portion of the plants to be more responsive to market signals and ramp output accordingly. At the time of our initial filing, we were already bidding Prairie Island Unit 1 into the Day-Ahead Market. Since that time, we have expanded our flexible operations capabilities to all three nuclear units, and at this time we can safely and efficiently ramp up to 280 MW – or over 15 percent – of our nuclear capacity in response to the market. This capability will help us integrate more renewables on our system, while still utilizing our nuclear fleet as a carbon-free, stable and reliable source of energy. In short, our ability to make renewables and nuclear work together helps us increase the amount of clean energy we can provide our customers.

2. *Nuclear Hydrogen Pilot*

We are also looking for additional opportunities to incorporate our nuclear fleet into our clean energy future. This includes alternate use cases for the low-cost, clean energy produced by our plants, that could allow us to integrate even more variable renewable energy onto the grid.

To this end, we will soon kick off a partnership with INL, the DOE, and two other utilities to examine technical and economic feasibility of using nuclear energy to produce hydrogen through a process called electrolysis. In total, the project will receive approximately $11.5 million in grant funding from the DOE. The Company will receive around $1.3 million of this funding to work with INL to examine the economic feasibility of using our nuclear units' electricity to produce hydrogen fuels. The project will also include deployment of a low-temperature electrolyzer at

FirstEnergy's Davis Besse nuclear plant in Ohio, and another economic feasibility study for the Palo Verde Nuclear Generating Station, owned by Arizona Public Service. The utilities are currently in the final stages of negotiating the project scope with INL and DOE. We expect the pilot to kick off later in 2020 and run through 2022.

The findings from this pilot project have the potential to not only support the Company's goals of achieving 100 percent clean energy by 2050, but also potentially reduce carbon across other sectors. Clean hydrogen produced with energy from our nuclear units could, for example, provide a method of long-duration energy storage and clean firm, dispatchable generation. Instead of ramping down nuclear units during periods of high renewable generation, we could use the excess clean electricity on our system to shift load and produce hydrogen at low cost. That hydrogen could then be used to produce electricity at times when variable renewable generation is not available. Hydrogen is also currently used as key fuel in some industrial processes, such as steel manufacturing, and fleet vehicle operations, but the method currently used to produce it – called steam reformation – uses fossil fuels. Clean electrolysis could support carbon reduction in these heavy manufacturing and industrial processes that are typically challenging to mitigate. Finally, it is possible that clean hydrogen could become an economic fuel source for transportation, supporting carbon reductions in our economy's most carbon-intensive segment.

C. Spent Nuclear Fuel Update

The Company continues to lead discussions of spent nuclear fuel and finding both permanent and interim storage solutions. This is done through a variety of channels including our interactions with Congress and congressional staff, and through industry trade initiatives, such as through the Nuclear Energy Institute (NEI), and the Nuclear Waste Strategy Coalition (NWSC or Coalition).

Xcel Energy was one of the major sponsors and participants in a table top exercise organized by NEI last year at Prairie Island. The exercise was intended to begin the dialogue and foster cooperation among key decisionmakers around the actions needed to transport spent fuel from a reactor site to a consolidated interim storage facility (CISF). The exercise modeled the transportation of spent fuel from a hypothetical nuclear power plant (located between the Prairie Island and Kewaunee sites) to a hypothetical centralized interim storage in the vicinity of the New Mexico/Texas border.

1. *Permanent Repository*

Xcel Energy is working with federal authorities to encourage development of a permanent storage solution. The application to license the Yucca Mountain permanent repository remains pending before the NRC. The NRC Staff's technical and environmental reviews are essentially complete, but the adjudicatory hearings on the application before the NRC Atomic Safety and Licensing Board remain suspended pending Congressional appropriations for both DOE and NRC. Numerous contentions submitted by Nevada and other opponents remain to be litigated and must be resolved before the NRC can license the project.

2. *Consolidated Interim Storage Facility (CISF)*

Two private, interim storage initiatives have submitted licenses for operation to the NRC. If approved, these CISF locations would consolidate and store the spent fuel until the permanent facility is built.

Interim Storage Partners, formed by Orano USA and Waste Control Specialists (WCS), is pursuing a license to construct a consolidated interim storage facility for used nuclear fuel at the existing WCS low-level waste disposal site in Andrews County, Texas. The NRC has issued a draft Environmental Impact Statement that is currently out for public comment and staff's most recent announced date for completing its review of the application and issuing the license is May 2021.

Holtec International has proposed the HI-STORE consolidated interim storage facility for a site in Eddy and Lea Counties in southeastern New Mexico. Holtec filed an application with the NRC for this facility in March 2017. The NRC issued a draft Environmental Impact Statement earlier this year that is currently out for public comment. Public hearings were held on June 24 and another is scheduled for July 9. The NRC Staff's most recently announced date for completing its review of the application and issuing the license is March 2021.

D. The Nuclear Fleet's Role in Our Updated Preferred Plan

Our nuclear units are a cornerstone of our current generation fleet as well as our clean energy future. Since our initial filing, the Company has updated our nuclear budgets in order to ensure our modeling takes into account the most current data, including general operating costs, as well as expected costs to achieve nuclear relicensing, for scenarios that propose extension. Our Supplement modeling continues to show that the lowest cost future generation portfolios include extending our nuclear units beyond their current licenses.

1. *Nuclear Budget Updates*

We made several updates to our nuclear budgets that feed into our modeling for this Supplement. First, we updated our budgets to reflect 2018 actuals for both capital and O&M. Beyond 2018, we provide an updated capital forecast and an updated O&M forecast from 2019-2022, after which we apply 2 percent annual escalation consistent with our 2019 budget data used for our initial filing. In addition to these changes, we made some modifications to the list of projects to which probabilities are assigned in the long-range plan. However, these changes result in very little overall net change to the estimated capital expenditures for nuclear in our Supplement Preferred Plan. We also updated the expense for the annual decommissioning accrual to align with the Commission's most recent decision in our 2017 Triennial Decommissioning Docket.

Finally, we introduced a refinement to our modeled costs to reflect the fact that we receive annual reimbursements from the DOE for each year's dry fuel storage expenses. Because these DOE reimbursements typically get refunded to customers (or occasionally get applied to customer obligations such as the decommissioning accrual), we concluded that it is reasonable to account for these annual reimbursements in our modeling so as not to overstate the cost of our nuclear operations.

For Monticello, our updated total estimated capital expenditures decreased from our 2019 budget by approximately $0.3 million. Our O&M estimate before loadings increased from our previous budget by approximately $28 million. This increase reflects higher realized 2018 and 2019 O&M results, which are subsequently escalated through 2040. Our budget update also includes a refined outage amortization estimate in the final year of operations.

For Prairie Island, our total capital budget estimate updates, increased relative to our 2019 budget by approximately $20 million for the years 2018 to 2034. Our O&M budget for the years 2020-2034 decreased from the previous budget by approximately $385 million. This adjustment reflects not only reductions in 2018 and 2019 spend compared to prior budgets, but also near-term budgets that are lower than in 2019, due in part to planned continuous improvement efforts. These near-term adjustments are then used to estimate spend out to 2034, which is partially offset by refining outage amortization in the final year of operations.

2. *Nuclear's Role in our Supplement Preferred Plan*

The Company's Supplement Preferred Plan continues to show benefits of a ten-year extension of our Monticello unit, to 2040, and operating Prairie Island units at least through their current license lives. These resources are essential to the achievement of our carbon reduction goals and are part of a cost-effective plan to achieve them. For the purposes of this Supplement, we examined capacity expansion scenarios both in Strategist and EnCompass. While there are some differences in specific portfolio outcomes, results are generally consistent in indicating that extending the lives of our nuclear units supports our system achieving significant carbon reduction in a least-cost manner.

a. Modeled scenarios and results

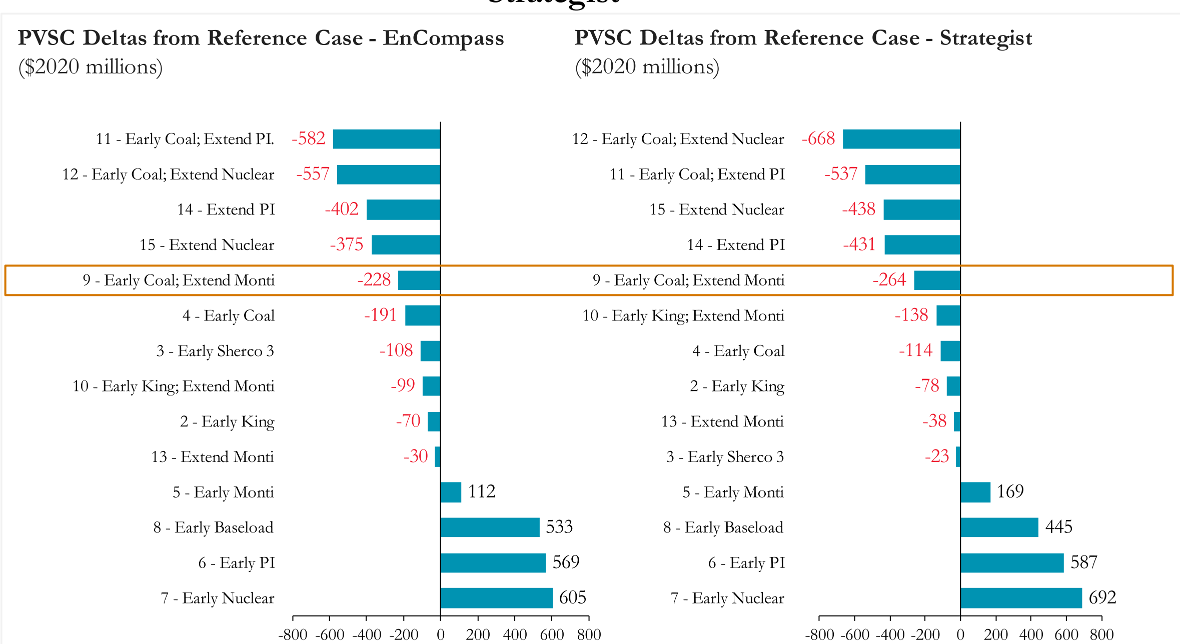
As in our initial filing, we modeled several baseload scenarios in which we tested both the present value of societal cost (PVSC) and present value of revenue requirements (PVRR) outcomes of either retiring early or extending Monticello and Prairie Island (as well as our remaining coal units). Scenarios that include modifications to nuclear retirement dates are:

- 5 – Early Monticello (Monti) Retirement (retires in 2026)
- 6 – Early Prairie Island (PI) Retirement (Units 1 and 2 retire in 2024 and 2025, respectively)
- 7 – Early All Nuclear Retirement (retires Monti and PI early, per dates in Scenarios 5 and 6)
- 8 – Early All Baseload (retires all nuclear early, per dates in Scenarios 5 and 6, and all coal early)
- 9 – Early Coal; Extend Monti (extends Monti operations to 2040 – 10 years beyond its current license life – and retires coal early)
- 10 – Early King; Extend Monti (extends Monti to 2040, while retiring the King coal plant early)
- 11 – Early Coal; Extend PI (PI Units 1 and 2 remain operational until 2043 and 2044 – or 10 years past their current license expirations – and all coal is retired early)

- 12 – Early Coal; Extend All Nuclear (extends all three nuclear units 10 years beyond their current license expiration dates while retiring all coal units early)
- 13 – Extend Monti (Monti remains operational until 2040)
- 14 – Extend PI (Units 1 and 2 remain operational until 2043 and 2044)
- 15 – Extend All Nuclear (extends all three nuclear units 10 years beyond current license expiration dates)

Our updated analysis continues to show that extending the lives of our nuclear units is a beneficial and least-cost option when compared to the Reference Case and most other scenarios. It also shows that all scenarios retiring our nuclear units before their current license expirations would be costlier to customers than the Reference Case. The following Figure shows updated Preferred Plan cost-effectiveness results, on a PVSC basis, from both EnCompass and Strategist modeling.

Figure VIII-2: Scenario PVSC Deltas from Reference Case –EnCompass and Strategist



As in our original filing, the Supplement Preferred Plan (based on Scenario 9) is not the absolute least cost scenario of the 15 options considered; multiple lesser-cost options include a Prairie Island extension. While we are not currently proposing to pursue a Prairie Island license extension at this time – for reasons further discussed below – these results continue to support our initial findings that extending all our nuclear units beyond their existing lives, in conjunction with retiring our coal units early, is in our customers' interests and contributes to achievement of our carbon reduction goals.[75]

b. Action Plan with Respect to Nuclear Units

In order to realize customer benefits from our Supplement Preferred Plan, the Company must begin activities to relicense the Monticello unit within the five-year action plan window. As we discussed in our initial filing, there are two key initial components to achieving Monticello extension that will need to begin between now and the mid-2020s: 1) the NRC's SLR process and 2) a Minnesota Certificate of Need (CN) for additional dry cask fuel storage. Specifically, in this Supplement Preferred Plan's action plan we continue to propose to begin work on the SLR application, which we plan to kick off in mid-2021. We anticipate this work will take approximately two years, which means we would file for SLR approval in early 2023. Concurrently, we plan to begin developing a CN proposal for the Commission this year, which we tentatively plan to file in 2021, and for which we would hope to receive approval in 2023.

As noted above, we are not proposing a Prairie Island extension as part of our Supplement Preferred Plan at this time; rather, we believe deferring a decision on a proposed Prairie Island extension is the best path forward to allow additional time to work with our host communities, while also not precluding us from pursuing customer savings in the future. Scenarios that include extending the license for Prairie Island in addition to Monticello are effectively identical to our Preferred Plan in the first five years. We expect to file our next Resource Plan – covering the 2024-2038 planning period – sometime in 2023. Thus, while we need to begin relicensing approval activities for Monticello in a relatively short timeframe, we have time to reevaluate the potential benefits of Prairie Island extension.

Given the rapidly evolving nature of clean energy technology costs and development, as well as the policy environment in Minnesota and federally, we believe maintaining optionality on a Prairie Island extension is the best path forward. Further, deferring those decisions will provide the Company additional time to engage the Prairie Island

[75] We also note that the benefits of more flexible nuclear operations and potential value of nuclear hydrogen generation have not been factored into our Supplement Preferred Plan analysis. This means that there may be additional customer savings and carbon reduction upside associated with both Monticello and Prairie Island life extension, when accounting for this additional flexibility.

Indian Community, City of Red Wing, and other community interests on the benefits and concerns regarding the plant's life extension. We will, for example, have additional time to work with other utilities and relevant authorities on significant issues of concern, such as an interim spent fuel storage solution discussed previously. We also continue to track nuclear generation technology development, such as design and approval progress on advanced reactor designs discussed in our initial filing.

IX. LOAD AND RESOURCES TABLES

Table IX-1: EnCompass Reference Case (Scenario 1) System Load and Resources, UCAP

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Forecast gross Load	10,502	10,563	10,635	10,711	10,780	10,842	10,911	10,982	11,053	11,119	11,184	11,253	11,324	11,391	11,452
EV Forecast	8	12	17	25	35	44	53	65	79	99	126	163	214	273	336
Forecast EE (reduction in load)	1,395	1,508	1,550	1,625	1,723	1,817	1,907	1,975	2,052	2,189	2,269	2,367	2,448	2,521	2,583
Forecasted Net Load	9,115	9,067	9,101	9,111	9,092	9,068	9,057	9,072	9,080	9,029	9,041	9,049	9,090	9,143	9,205
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,659	8,614	8,646	8,655	8,638	8,615	8,604	8,618	8,626	8,578	8,589	8,597	8,636	8,686	8,745
MISO PRM	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%
NSP Obligation	9,430	9,380	9,416	9,426	9,406	9,382	9,370	9,385	9,393	9,341	9,354	9,362	9,404	9,459	9,523

Reference Plan - Scenario 1 - UCAP

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Load Management (existing)	1,012	1,027	1,041	1,055	1,066	1,072	1,077	1,078	1,077	1,071	1,059	1,048	1,037	1,026	1,016
Load Management (potential study)	33	165	232	294	341	382	394	407	423	440	458	478	499	521	545
Coal	2,295	2,295	2,295	2,295	1,647	1,647	1,647	994	994	994	994	994	994	994	994
Nuclear	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,019	1,019	1,019	498	0
Natural Gas/Oil	3,858	3,858	3,858	3,858	3,713	3,403	3,112	2,831	2,831	2,831	2,831	2,288	2,012	2,012	2,012
Sherco CC	0	0	0	0	0	0	0	728	728	728	728	728	728	728	728
Biomass/RDF	110	110	110	86	86	61	61	61	29	29	29	19	19	19	19
Hydro	881	1,001	993	993	993	162	162	162	162	162	162	162	156	152	152
Wind	498	623	672	647	635	631	626	611	605	583	582	566	563	498	479
Grid-Scale Solar	129	129	128	127	122	116	110	105	99	94	88	83	78	73	72
S*R Community Solar	329	357	394	421	409	392	376	359	343	326	309	292	276	259	259
Distributed Solar	37	45	53	60	64	68	71	74	76	78	78	79	78	77	81
Total Existing Resources	10,824	11,252	11,418	11,478	10,717	9,576	9,278	9,052	9,007	8,976	8,338	7,757	7,459	6,857	6,358
Net Resource (Need)/Surplus	1,394	1,871	2,002	2,052	1,311	195	-92	-334	-386	-365	-1,016	-1,605	-1,945	-2,602	-3,166
Future Firm Peaking	0	0	0	0	0	0	0	0	0	0	0	321	642	1,605	1,925
Future Solar	0	0	0	0	0	230	440	420	600	760	1,080	1,190	1,120	1,050	1,050
Future Wind	0	0	0	0	0	0	0	0	0	0	0	125	251	376	501
Total New Resources	0	0	0	0	0	230	440	420	600	760	1,080	1,636	2,012	3,030	3,476
Projected Net Position (Need)/Surplus	1,394	1,871	2,002	2,052	1,311	425	348	86	214	395	64	31	67	429	311

Table IX-2: EnCompass Reference Case (Scenario 1) System Load and Resources, ICAP

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Forecast gross Load	10,502	10,563	10,635	10,711	10,780	10,842	10,911	10,982	11,053	11,119	11,184	11,253	11,324	11,391	11,452
EV Forecast	8	12	17	25	35	44	53	65	79	99	126	163	214	273	336
Forecast EE (reduction in load)	1,395	1,508	1,550	1,625	1,723	1,817	1,907	1,975	2,052	2,189	2,269	2,367	2,448	2,521	2,583
Forecasted Net Load	9,115	9,067	9,101	9,111	9,092	9,068	9,057	9,072	9,080	9,029	9,041	9,049	9,090	9,143	9,205
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,659	8,614	8,646	8,655	8,638	8,615	8,604	8,618	8,626	8,578	8,589	8,597	8,636	8,686	8,745
MISO PRM	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%
NSP Obligation	9,430	9,380	9,416	9,426	9,406	9,382	9,370	9,385	9,393	9,341	9,354	9,362	9,404	9,459	9,523
Reference Plan - Scenario 1 - ICAP															
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Load Management (existing)	1,048	1,063	1,078	1,092	1,103	1,108	1,113	1,114	1,113	1,108	1,096	1,084	1,073	1,063	1,052
Load Management (potential study)	34	168	236	299	346	388	401	414	430	447	466	486	507	529	553
Coal	2,390	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	1,028	1,028	1,028	1,028	1,028
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,092	1,092	1,092	546
Natural Gas/Oil	4,735	4,735	4,735	4,735	4,735	4,544	4,186	3,811	3,505	3,505	3,505	2,726	2,726	2,428	2,428
Sherco CC	0	0	0	0	0	0	0	835	835	835	835	835	835	835	835
Biomass/RDF	141	137	137	135	111	77	77	77	42	42	42	27	27	27	27
Hydro	687	806	792	792	792	742	292	291	291	291	291	291	282	282	278
Wind	3,766	4,215	4,206	4,056	3,971	3,964	3,921	3,790	3,782	3,622	3,569	3,542	3,434	2,811	2,709
Grid-Scale Solar	258	257	256	254	253	252	251	249	248	247	246	244	243	242	241
S*R Community Solar	658	714	787	841	852	853	854	855	857	858	859	860	861	862	863
Distributed Solar	83	98	112	126	140	154	169	183	197	210	224	238	251	265	277
Total Existing Resources	15,537	16,322	16,467	16,459	16,431	15,529	14,709	15,066	14,066	13,931	13,899	12,453	12,360	11,464	10,837
Net Resource (Need)/Surplus	6,107	6,941	7,051	7,033	7,025	6,147	5,339	5,681	4,673	4,590	4,545	3,092	2,956	2,005	1,314
Future Firm Peaking	0	0	0	0	0	0	0	0	0	0	0	374	748	1,870	2,244
Future Solar	0	0	0	0	0	500	1,000	1,000	1,500	2,000	3,000	3,500	3,500	3,500	3,500
Future Wind	0	0	0	0	0	0	0	0	0	0	0	750	1,500	2,250	3,000
Total New Resources	0	0	0	0	0	500	1,000	1,000	1,500	2,000	3,000	4,624	5,748	7,620	8,744
Projected Net Position (Need)/Surplus	6,107	6,941	7,051	7,033	7,025	6,647	6,339	6,681	6,173	6,590	7,545	7,716	8,704	9,625	10,058

Table IX-3: EnCompass Supplement Preferred Plan (Scenario 9) System Load and Resources, UCAP

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Forecast gross Load	10,502	10,563	10,635	10,711	10,780	10,842	10,911	10,982	11,053	11,119	11,184	11,253	11,324	11,391	11,452
EV Forecast	8	12	17	25	35	44	53	65	79	99	126	163	214	273	336
Forecast EE (reduction in load)	1,395	1,508	1,550	1,625	1,723	1,817	1,907	1,975	2,052	2,189	2,269	2,367	2,448	2,521	2,583
Forecasted Net Load	9,115	9,067	9,101	9,111	9,092	9,068	9,057	9,072	9,080	9,029	9,041	9,049	9,090	9,143	9,205
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,659	8,614	8,646	8,655	8,638	8,615	8,604	8,618	8,626	8,578	8,589	8,597	8,636	8,686	8,745
MISO PRM	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%
NSP Obligation	9,430	9,380	9,416	9,426	9,406	9,382	9,370	9,385	9,393	9,341	9,354	9,362	9,404	9,459	9,523

Supplement Preferred Plan - Scenario 9 - UCAP

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Load Management (existing)	1,012	1,027	1,041	1,055	1,066	1,072	1,077	1,078	1,077	1,071	1,059	1,048	1,037	1,026	1,016
Load Management (potential study)	33	165	232	294	341	382	394	407	423	440	458	478	499	521	545
Coal	2,295	2,295	2,295	2,295	1,647	1,647	1,647	994	994	511	0	0	0	0	0
Nuclear	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,120	622
Natural Gas/Oil	3,858	3,858	3,858	3,858	3,713	3,403	3,112	2,831	2,831	2,831	2,831	2,288	2,012	2,012	2,012
Sherco CC	0	0	0	0	0	0	0	728	728	728	728	728	728	728	728
Biomass/RDF	110	110	110	86	86	61	61	61	29	29	29	19	19	19	19
Hydro	881	1,001	993	993	993	162	162	162	162	162	162	162	156	152	152
Wind	498	623	672	647	635	631	626	611	605	583	582	566	563	498	479
Grid-Scale Solar	129	129	128	127	122	116	110	105	99	94	88	83	78	73	72
S*R Community Solar	329	357	394	421	409	392	376	359	343	326	309	292	276	259	259
Distributed Solar	37	45	53	60	64	68	71	74	76	78	78	79	78	77	81
Total Existing Resources	10,824	11,252	11,418	11,478	10,717	9,576	9,278	9,052	9,007	8,493	7,967	7,386	7,087	6,486	5,986
Net Resource (Need)/Surplus	1,394	1,871	2,002	2,052	1,311	195	-92	-334	-386	-848	-1,387	-1,976	-2,317	-2,973	-3,537
Future Firm Peaking	0	0	0	0	0	0	0	0	0	0	321	963	1,284	1,925	2,246
Future Solar	0	0	0	0	0	230	440	420	600	950	1,260	1,190	1,120	1,050	1,050
Future Wind	0	0	0	0	0	0	0	0	0	0	0	0	125	251	376
Total New Resources	0	0	0	0	0	230	440	420	600	950	1,581	2,153	2,529	3,226	3,672
Projected Net Position (Need)/Surplus	1,394	1,871	2,002	2,052	1,311	425	348	86	214	102	194	176	212	253	135

Table IX-4: EnCompass Supplement Preferred Plan (Scenario 9) System Load and Resources, ICAP

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Forecast gross Load	10,502	10,563	10,635	10,711	10,780	10,842	10,911	10,982	11,053	11,119	11,184	11,253	11,324	11,391	11,452
EV Forecast	8	12	17	25	35	44	53	65	79	99	126	163	214	273	336
Forecast EE (reduction in load)	1,395	1,508	1,550	1,625	1,723	1,817	1,907	1,975	2,052	2,189	2,269	2,367	2,448	2,521	2,583
Forecasted Net Load	9,115	9,067	9,101	9,111	9,092	9,068	9,057	9,072	9,080	9,029	9,041	9,049	9,090	9,143	9,205
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,659	8,614	8,646	8,655	8,638	8,615	8,604	8,618	8,626	8,578	8,589	8,597	8,636	8,686	8,745
MISO PRM	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%	8.90%
NSP Obligation	9,430	9,380	9,416	9,426	9,406	9,382	9,370	9,385	9,393	9,341	9,354	9,362	9,404	9,459	9,523
							Supplement Preferred Plan - Scenario 9 - ICAP								
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Load Management (existing)	1,048	1,063	1,078	1,092	1,103	1,108	1,113	1,114	1,113	1,108	1,096	1,084	1,073	1,063	1,052
Load Management (potential study)	34	168	236	299	346	388	401	414	430	447	466	486	507	529	553
Coal	2,390	2,390	2,390	2,390	2,390	1,708	1,708	1,708	1,028	1,028	517	0	0	0	0
Nuclear	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,738	1,192
Natural Gas/Oil	4,735	4,735	4,735	4,735	4,735	4,544	4,186	3,811	3,505	3,505	3,505	2,726	2,726	2,428	2,428
Sherco CC	0	0	0	0	0	0	0	835	835	835	835	835	835	835	835
Biomass/RDF	141	137	137	135	111	77	77	77	42	42	42	27	27	27	27
Hydro	687	806	792	792	792	742	292	291	291	291	291	291	282	282	278
Wind	3,766	4,215	4,206	4,056	3,971	3,969	3,921	3,790	3,782	3,622	3,569	3,542	3,434	2,811	2,709
Grid-Scale Solar	258	257	256	254	253	252	251	249	248	247	246	244	243	242	241
S*R Community Solar	658	714	787	841	852	853	854	855	857	858	859	860	861	862	863
Distributed Solar	83	98	112	126	140	154	169	183	197	210	224	238	251	265	277
Total Existing Resources	15,537	16,322	16,467	16,459	16,431	15,534	14,709	15,066	14,066	13,931	13,388	12,071	11,978	11,082	10,455
Net Resource (Need)/Surplus	6,107	6,941	7,051	7,033	7,025	6,152	5,339	5,681	4,673	4,590	4,034	2,710	2,574	1,623	932
Future Firm Peaking	0	0	0	0	0	0	0	0	0	0	374	1,122	1,496	2,244	2,618
Future Solar	0	0	0	0	0	500	1,000	1,000	1,500	2,500	3,500	3,500	3,500	3,500	3,500
Future Wind	0	0	0	0	0	0	0	0	0	0	0	0	750	1,500	2,250
Total New Resources	0	0	0	0	0	500	1,000	1,000	1,500	2,500	3,874	4,622	5,746	7,244	8,368
Projected Net Position (Need)/Surplus	6,107	6,941	7,051	7,033	7,025	6,652	6,339	6,681	6,173	7,090	7,908	7,332	8,320	8,867	9,300

X. MODELING SCENARIO SENSITIVITY ANALYSIS – PVRR AND PVSC SUMMARY

In the course of Supplement modeling, the Company conducted several hundred modeling runs testing how different assumptions affect capacity expansion portfolio and cost outcomes. We discuss several of these in Section II. Modeling Framework and Results but include here a description and results from additional sensitivity testing runs. These runs and results fall into two primary categories; A) individual sensitivities conducted on all 15 baseload scenarios, and B) alternate sensitivities conducted on only the Reference Case and Supplement Preferred Plan.

A. Individual Sensitivities

As noted above, the Company tested several sensitivities on our baseload scenarios; these individual sensitivities vary one input at a time in order to isolate the effect of those changes on capacity expansion plans and net present value cost/savings. These represent the "standard" set of individual sensitivities we used in our initial July 2019 filing and across many other dockets that examine the economic effects of proposed resource acquisitions. They include:

- *Load*. The low load sensitivity includes high customer adoption-based DER growth and higher EE savings (i.e. it includes all three EE Bundles), which reduces load. The high load sensitivity includes high electrification load.
- *Fuel Price/Market Costs*. High and low-price sensitivities were performed by adjusting the growth rate up and down, respectively, by 50 percent from the base forecast starting in year 2022.
- *CO2 Values*. To examine the effect of CO_2 pricing, we tested high and low-cost sensitivities. We also performed a sensitivity evaluating no CO_2 cost. The PVSC Base Case CO_2 values are based on the high externality cost values for CO_2 as determined by the Minnesota Commission through 2024.[76] The PVSC Base Case values starting in 2025 are based on the "high" end of the range of regulated costs. Below is the list of carbon sensitivities.
  - Low Externality
  - Low Externality, Low Regulatory

[76] Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.) at 31.

- Mid Externality, Mid Regulatory
- High Externality
- PVRR, or No Externality or Regulatory

- *Externalities.* Criteria pollutants values are derived from the high and low values for each of the three geographic locations in the Minnesota Commission Order,[77] with existing plants assigned the appropriate area and generic units assigned to "rural." The midpoint externality costs are the average of the low and high values. The high, low and midpoint externality costs are used in conjunction with the CO_2 sensitivities described above.
- *Resource Costs.* For wind, solar and battery energy storage, we use NREL's 2019 ATB report to provide high and low technology cost sensitivity inputs. We use these cost forecasts directly in our sensitivity analysis, with adjustments for interconnection costs as needed. We did not adjust capital costs for thermal resources such as the generic CC or CTs, so all scenarios include our base cost assumptions for those resources.
- *Markets Interactions* – Assumptions regarding MISO market sales and purchases have become increasingly important as we integrate higher levels of renewable resources on to our system. By participating in MISO, we can take advantage of an efficient market to make sales into the larger MISO footprint when our production exceeds our native load requirements, and purchases when market prices are lower than the cost of our generators. The addition of our 1,550 MW wind portfolio[78] and other recent wind resource additions will create a significant amount of energy that exceeds the needs of our native load. For 2022, when the recent wind additions will be fully operational, our Supplement Preferred Plan results show 11,600 GWh of sales into the MISO market. In previous Strategist modeling, we included a "no markets" sensitivity, where market interactions were not allowed. This sensitivity was designed to provide insight into whether a resource was being added to serve native load or was reliant on the ability to utilize the MISO market. However, with the recent wind additions to our system, we do not believe a "no markets" sensitivity provides useful results. Without the availability of the market, the models treat any energy in excess of load as "dump" energy, and the recently approved wind portfolio creates a significant amount of dump energy in all scenarios when markets are turned off. If markets are not available, the model will try to solve

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[77] Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.
[78] Per Docket No. E002/M-16-777.

the "dump" energy problem, by finding an expansion plan that can better incorporate use of that energy, often with unexpected or unrealistic results, instead of considering that the excess energy would likely be sold into the market and not actually be "valueless."

- *Market Sensitivities* In the base modeling, an adder for the regulatory cost of carbon is placed on the locational marginal price (LMP) in the market for both purchases and sales using the forecasted annual average MISO emissions rate. We note that this assumption could have the effect of increasing the sales from our dispatchable generation if the market price on sales exceeds the dispatch costs. Therefore, we created two additional sensitivities to address this concern and to better address the risk related to market assumptions. First, we included a sensitivity with no carbon adder on market sales. This sensitivity will reduce the price for sales into the market and therefore, the risk that a dispatchable unit with be utilized due to the inclusion of the carbon adder. Second, we included a sensitivity that shapes the carbon adder based on the implied heat rate of the LMP for each hour. By shaping to the implied heat rate of the LMP, this carbon adder assumption is intended to better reflect the carbon intensity of the marginal unit on the MISO system. We also note that, as in our initial filing, we have run high and low fuel and market price sensitivities. We acknowledge that assumptions related to market interactions will need further refinement as markets evolve and more renewable resources are added. We are open to working with the Department and other stakeholders to develop further analysis in this Resource Plan or subsequent proceedings related to market interactions.

B. Alternate Assumptions Sensitivities

We also tested several alternate assumption sensitivities to provide estimates of the impacts of assumptions or constraints we changed in modeling since our initial filing. We ran these alternate sensitivities on the Supplement Preferred Plan only. These include:

- *Early wind availability*. Our base assumptions constrain the model from selecting wind resources prior to 2026, to reflect MISO transmission interconnection queue constraints. This sensitivity relaxes this constraint and allows the models to select generic wind resources starting in 2023. Our analysis found that this assumption had no influence on the results, as neither Strategist or EnCompass modeling selected any early availability wind.

- *Solar ELCC*. Our base assumptions include a solar ELCC values that declines from 50 percent to 30 percent between 2023-2033. This alternate sensitivity examined the effect of maintaining a 50 percent ELCC throughout the modeling period. As expected, a higher capacity accreditation value results in the models selecting more solar at an overall lower portfolio cost. That said, we believe a declining ELCC assumption is consistent with MISO and other utilities' long-term planning approaches and more appropriately reflects the reality of solar resources' ability to meet capacity needs in markets with increasing solar adoption.
- *Unconstrained sales/purchases*. Our base assumptions enforce a market sales constraint equal to 25 percent of retail sales in a given year in the course of capacity expansion modeling in EnCompass.[79] In this sensitivity, this constraint is relaxed in EnCompass, in both the capacity expansion and production costing model runs. The results of this sensitivity show higher costs than the Supplement Preferred Plan, indicating that – given the simplifying assumptions used in the capacity expansion runs – the model selected more resources that received lower market revenue than expected when analyzed in production costing runs, and thus cost to customers increased. This indicates that an unconstrained market sales assumption leads EnCompass to overvalue incremental resources.
- *DR and EE bundles*. In the EnCompass modeling, the first DR bundle and the first two EE bundles were included in our baseline modeling, and the remaining bundles were not made available for the model to select in the optimization. As in our initial filing, we took this approach to reduce model complexity and improve runtimes. However, to test this assumption, we ran alternate sensitivities that individually forced-in the next EE and DR bundles to test whether the PVSC and PVRR results indicate either option would be cost effective relative to other resource options. The results confirmed that incremental bundles of EE and/or DR were not cost effective in the EnCompass modeling results.

[79] Note that we did not enforce the same constraint in Strategist as it does not have the ability to constrain market sales.

ENCOMPASS RESULTS

Table X-1: EnCompass Net Present Value Results for Baseload Scenarios PVSC and PVRR, and Sensitivities B-I

Parent Run	Description	Base - PVSC	A-PVRR	B-Low Gas/Coal/ Markets	C-High Gas/Coal/ Markets	D-Low Load (High DER)	E-High Load (Electrification)	F-Low Resource Cost	G-High Resource Cost	I-Low Externality
Scenario 1	*REFERENCE*	$41,050	$37,479	$40,928	$41,165	$41,793	$43,659	$39,591	$43,178	$39,071
Scenario 2	*EARLY KING*	$40,980	$37,436	$40,867	$41,084	$41,749	$43,628	$39,505	$43,125	$38,964
Scenario 3	*EARLY SH3*	$40,943	$37,604	$40,842	$41,006	$41,658	$43,561	$39,416	$43,185	$39,044
Scenario 4	*EARLY COAL*	$40,859	$37,571	$40,779	$40,898	$41,629	$43,550	$39,307	$43,120	$38,935
Scenario 5	*EARLY MONTI*	$41,163	$37,487	$41,018	$41,303	$41,906	$43,732	$39,634	$43,338	$39,098
Scenario 6	*EARLY PI*	$41,619	$37,765	$41,445	$41,788	$42,298	$44,198	$39,905	$44,031	$39,428
Scenario 7	*EARLY All NUCLEAR*	$41,655	$37,600	$41,431	$41,881	$42,412	$44,339	$39,879	$44,119	$39,326
Scenario 8	*EARLY BASELOAD*	$41,583	$37,660	$41,335	$41,815	$42,398	$44,160	$39,887	$43,903	$39,156
Scenario 9	*EARLY COAL; EXTEND MONTI*	$40,823	$37,563	$40,743	$40,863	$41,571	$43,470	$39,474	$42,772	$38,910
Scenario 10	*EARLY KING; EXTEND MONTI*	$40,952	$37,429	$40,852	$41,035	$41,665	$43,526	$39,643	$42,849	$38,951
Scenario 11	*EARLY COAL; EXTEND PI*	$40,468	$37,234	$40,431	$40,443	$41,280	$43,120	$39,148	$42,339	$38,589
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	$40,493	$37,274	$40,479	$40,438	$41,256	$43,110	$39,352	$42,130	$38,654
Scenario 13	*EXTEND MONTI*	$41,020	$37,480	$40,923	$41,099	$41,838	$43,591	$39,689	$42,962	$39,067
Scenario 14	*EXTEND PI*	$40,648	$37,110	$40,589	$40,672	$41,470	$43,316	$39,371	$42,468	$38,724
Scenario 15	*EXTEND All NUCLEAR*	$40,675	$37,209	$40,641	$40,670	$41,477	$43,240	$39,576	$42,241	$38,804

The numbers above represent 2020-2045 total net present value (NPV) costs.

Table X-2: EnCompass Net Present Value Deltas for Baseload Scenarios PVSC and PVRR, and Sensitivities B-I

Parent Run	Description	Base - PVSC	A-PVRR	B-Low Gas/Coal/ Markets	C-High Gas/Coal/ Markets	D-Low Load (High DER)	E-High Load (Electrification)	F-Low Resource Cost	G-High Resource Cost	I-Low Externality
Scenario 1	*REFERENCE*	$0	$0	$0	$0	$0	$0	$0	$0	$0
Scenario 2	*EARLY KING*	($70)	($44)	($60)	($81)	($44)	($32)	($86)	($52)	($108)
Scenario 3	*EARLY SH3*	($108)	$124	($86)	($159)	($134)	($99)	($175)	$7	($27)
Scenario 4	*EARLY COAL*	($191)	$92	($149)	($267)	($163)	($110)	($284)	($57)	($136)
Scenario 5	*EARLY MONTI*	$112	$8	$90	$138	$113	$73	$43	$160	$27
Scenario 6	*EARLY PI*	$569	$286	$517	$623	$505	$539	$314	$854	$357
Scenario 7	*EARLY All NUCLEAR*	$605	$121	$503	$716	$619	$680	$288	$942	$255
Scenario 8	*EARLY BASELOAD*	$533	$181	$407	$650	$605	$501	$296	$725	$85
Scenario 9	*EARLY COAL; EXTEND MONTI*	($228)	$83	($185)	($302)	($222)	($189)	($117)	($406)	($161)
Scenario 10	*EARLY KING; EXTEND MONTI*	($99)	($50)	($75)	($130)	($128)	($133)	$52	($329)	($121)
Scenario 11	*EARLY COAL; EXTEND PI*	($582)	($245)	($497)	($722)	($513)	($539)	($443)	($838)	($483)
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	($557)	($206)	($449)	($727)	($537)	($549)	($240)	($1,048)	($418)
Scenario 13	*EXTEND MONTI*	($30)	$1	($5)	($66)	$45	($68)	$98	($216)	($5)
Scenario 14	*EXTEND PI*	($402)	($370)	($339)	($493)	($322)	($344)	($220)	($709)	($347)
Scenario 15	*EXTEND All NUCLEAR*	($375)	($270)	($287)	($495)	($316)	($419)	($15)	($937)	($268)

The deltas above were derived by comparing the total NPV costs of each scenario to the Reference Case/Scenario 1.

Table X-3: EnCompass Net Present Value Results for Baseload Scenario Sensitivities J-V

Parent Run	Description	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs	P - Combo "DBF"	Q - Combo "ECF"	S - No Carbon Adder for Sales	U - Hourly Carbon, Retail Load Shape	V - Optimize with Externality in model
Scenario 1	*REFERENCE*	$38,248	$39,667	$45,052	$37,196	$40,919	$42,950	$44,122	$40,956	$39,175
Scenario 2	*EARLY KING*	$38,192	$39,599	$44,699	$37,171	$40,825	$42,887	$44,208	$40,878	$39,058
Scenario 3	*EARLY SH3*	$38,287	$39,630	$44,606	$37,330	$40,769	$42,765	$44,276	$40,879	$39,012
Scenario 4	*EARLY COAL*	$38,234	$39,558	$44,221	$37,313	$40,609	$42,559	$44,191	$40,762	$38,936
Scenario 5	*EARLY MONTI*	$38,289	$39,743	$45,108	$37,215	$41,061	$43,096	$44,422	$41,103	$39,223
Scenario 6	*EARLY PI*	$38,617	$40,135	$45,569	$37,506	$40,578	$43,364	$44,956	$41,558	$39,660
Scenario 7	*EARLY All NUCLEAR*	$38,516	$40,102	$45,608	$37,361	$40,681	$43,483	$44,961	$41,624	$39,768
Scenario 8	*EARLY BASELOAD*	$38,465	$40,035	$44,890	$37,404	$40,928	$43,209	$44,844	$41,560	$39,664
Scenario 9	*EARLY COAL; EXTEND MONTI*	$38,205	$39,526	$44,203	$37,286	$40,702	$42,484	$44,111	$40,731	$38,914
Scenario 10	*EARLY KING; EXTEND MONTI*	$38,176	$39,577	$44,688	$37,158	$40,861	$42,688	$44,139	$40,859	$39,029
Scenario 11	*EARLY COAL; EXTEND PI*	$37,881	$39,186	$43,862	$36,970	$39,883	$41,099	$43,350	$40,432	$38,586
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	$37,936	$39,226	$43,937	$37,032	$40,262	$41,118	$43,217	$40,456	$38,582
Scenario 13	*EXTEND MONTI*	$38,238	$39,647	$45,053	$37,190	$40,989	$42,897	$44,048	$40,955	$39,101
Scenario 14	*EXTEND PI*	$37,893	$39,288	$44,694	$36,852	$40,142	$41,282	$43,431	$40,599	$38,718
Scenario 15	*EXTEND All NUCLEAR*	$37,964	$39,338	$44,761	$36,935	$40,533	$41,496	$43,542	$40,623	$38,729

The numbers above represent 2020-2045 total NPV costs.

Table X-4: EnCompass Net Present Value Deltas for Baseload Scenario Sensitivities J-V

Parent Run	Description	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs	P - Combo "DBF"	Q - Combo "ECF"	S - No Carbon Adder for Sales	U - Hourly Carbon, Retail Load Shape	V - Optimize with Externality in model
Scenario 1	*REFERENCE*	$0	$0	$0	$0	$0	$0	$0	$0	$0
Scenario 2	*EARLY KING*	($56)	($68)	($353)	($25)	($94)	($64)	$85	($78)	($116)
Scenario 3	*EARLY SH3*	$39	($37)	($446)	$133	($151)	($185)	$153	($77)	($163)
Scenario 4	*EARLY COAL*	($14)	($109)	($831)	$117	($311)	($391)	$68	($194)	($239)
Scenario 5	*EARLY MONTI*	$41	$76	$56	$19	$141	$146	$299	$147	$48
Scenario 6	*EARLY PI*	$369	$468	$517	$310	($341)	$414	$834	$602	$485
Scenario 7	*EARLY All NUCLEAR*	$268	$435	$556	$165	($239)	$533	$839	$668	$593
Scenario 8	*EARLY BASELOAD*	$216	$368	($162)	$208	$9	$259	$722	$604	$489
Scenario 9	*EARLY COAL; EXTEND MONTI*	($43)	($141)	($849)	$90	($218)	($467)	($11)	($225)	($261)
Scenario 10	*EARLY KING; EXTEND MONTI*	($72)	($90)	($364)	($38)	($59)	($262)	$17	($97)	($145)
Scenario 11	*EARLY COAL; EXTEND PI*	($367)	($481)	($1,190)	($226)	($1,037)	($1,851)	($772)	($524)	($589)
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	($312)	($441)	($1,114)	($164)	($658)	($1,833)	($905)	($500)	($593)
Scenario 13	*EXTEND MONTI*	($10)	($20)	$1	($6)	$69	($54)	($74)	($1)	($74)
Scenario 14	*EXTEND PI*	($355)	($379)	($358)	($344)	($777)	($1,668)	($691)	($357)	($457)
Scenario 15	*EXTEND All NUCLEAR*	($284)	($329)	($291)	($261)	($387)	($1,454)	($581)	($333)	($445)

The deltas above were derived by comparing the total NPV costs of each baseload scenario to the Reference Case/Scenario 1.

Table X-5: EnCompass Net Present Value Results for North Dakota Scenario and Preferred Plan Sensitivities

Child Runs	Description	Base - PVSC	A-PVRR	I-Low Externality	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs
Scenario 1	Supplement North Dakota Scenario		$36,750					
Scenario 9	Supplement North Dakota Scenario		$36,949					
Scenario 9	EARLY COAL; EXTEND MONTI	$40,823	$37,563	$38,910	$38,205	$39,526	$44,203	$37,286
Scenario 9	Wind Available 2023 @ $500/kW	$40,812	$37,572					
Scenario 9	Solar @ 50% ELCC Throughout	$40,277	$36,769					
Scenario 9	Unconstrained Sales/Purchase Volume	$40,844	$37,721					
Scenario 9	Sherco CC Alternatives - 7HA01 1x1	$41,015	$37,796	$39,102	$38,444	$39,742	$44,185	$37,534
Scenario 9	Sherco CC Alternatives - 7HA02 1x1	$40,855	$37,600	$38,948	$38,275	$39,577	$44,091	$37,365
Scenario 9	Sherco CC Alternatives - 7HA02 2x1	$40,474	$37,209	$38,610	$37,857	$39,178	$44,077	$36,939
Scenario 9	Solar + Storage: "swap" 1st solar addition	$40,851	$37,607	$38,975	$38,270	$39,572	$44,232	$37,360
Scenario 9	Wind + Storage: "swap" 1st wind addition	$41,034	$37,744	$39,112	$38,401	$39,729	$44,440	$37,477
Scenario 9	DSM/DR - Add DR Bundle 2	$40,860	$37,588	$38,946	$38,243	$39,563	$44,231	$37,323
Scenario 9	DSM/DR - Add EE Bundle 3	$41,491	$38,342	$39,725	$39,021	$40,334	$45,000	$38,108

The numbers above represent 2020-2045 total NPV costs.

Table X-6: EnCompass Net Present Value Deltas for North Dakota Scenario and Preferred Plan Sensitivities

Child Runs	Description	Base - PVSC	A-PVRR	I-Low Externality	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs
Scenario 1	Supplement North Dakota Scenario		$0					
Scenario 9	Supplement North Dakota Scenario		$199					
Scenario 9	EARLY COAL; EXTEND MONTI	$0	$0	$0	$0	$0	$0	$0
Scenario 9	Wind Available 2023 @ $500/kW	($11)	$9					
Scenario 9	Solar @ 50% ELCC Throughout	($545)	($793)					
Scenario 9	Unconstrained Sales/Purchase Volume	$21	$159					
Scenario 9	Sherco CC Alternatives - 7HA01 1x1	$193	$234	$192	$239	$216	($18)	$249
Scenario 9	Sherco CC Alternatives - 7HA02 1x1	$32	$38	$38	$70	$51	($112)	$79
Scenario 9	Sherco CC Alternatives - 7HA02 2x1	($349)	($353)	($300)	($348)	($348)	($126)	($347)
Scenario 9	Solar + Storage: "swap" 1st solar addition	$29	$44	$65	$65	$46	$29	$74
Scenario 9	Wind + Storage: "swap" 1st wind addition	$212	$182	$202	$196	$203	$237	$191
Scenario 9	DSM/DR - Add DR Bundle 2	$37	$26	$36	$38	$38	$28	$38
Scenario 9	DSM/DR - Add EE Bundle 3	$668	$780	$815	$816	$808	$797	$822

The Supplement North Dakota Scenario deltas above were derived by comparing the total NPV costs of each scenario to Scenario 1 Supplement North Dakota Scenario. All other deltas were derived by comparing the total NPV costs of each Scenario 9 sensitivity to Scenario 9 – Early Coal; Extend Monti.

STRATEGIST RESULTS

Table X-7: Strategist Net Present Value Results for Baseload Scenarios PVSC and PVRR, and Sensitivities B-I

Parent Run	Description	Base - PVSC	A-PVRR	B-Low Gas/Coal/ Markets	C-High Gas/Coal/ Markets	D-Low Load (High DER)	E-High Load (Electrification)	F-Low Resource Cost	G-High Resource Cost	I-Low Externality
Scenario 1	*REFERENCE*	$43,082	$37,624	$42,736	$43,516	$43,821	$45,557	$41,468	$45,094	$40,604
Scenario 2	*EARLY KING*	$43,003	$37,729	$42,715	$43,373	$43,722	$45,482	$41,317	$45,080	$40,507
Scenario 3	*EARLY SH3*	$43,058	$37,977	$42,754	$43,429	$43,756	$45,488	$41,258	$45,330	$40,731
Scenario 4	*EARLY COAL*	$42,968	$37,817	$42,621	$43,405	$43,724	$45,423	$41,189	$45,210	$40,339
Scenario 5	*EARLY MONTI*	$43,250	$37,590	$42,814	$43,799	$43,930	$45,757	$41,665	$45,197	$40,567
Scenario 6	*EARLY PI*	$43,668	$37,758	$43,143	$44,328	$44,334	$46,128	$41,942	$45,731	$40,696
Scenario 7	*EARLY All NUCLEAR*	$43,774	$37,719	$43,202	$44,483	$44,427	$46,239	$42,062	$45,810	$40,672
Scenario 8	*EARLY BASELOAD*	$43,526	$37,754	$42,922	$44,283	$44,225	$46,027	$41,777	$45,535	$40,256
Scenario 9	*EARLY COAL; EXTEND MONTI*	$42,818	$37,896	$42,608	$43,061	$43,546	$45,288	$41,265	$44,756	$40,481
Scenario 10	*EARLY KING; EXTEND MONTI*	$42,944	$37,827	$42,784	$43,127	$43,681	$45,411	$41,392	$44,923	$40,644
Scenario 11	*EARLY COAL; EXTEND PI*	$42,544	$37,562	$42,333	$42,780	$43,268	$44,970	$40,955	$44,526	$40,095
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	$42,414	$37,600	$42,297	$42,518	$43,155	$44,867	$41,072	$44,053	$40,188
Scenario 13	*EXTEND MONTI*	$43,044	$37,674	$42,755	$43,398	$43,811	$45,516	$41,623	$44,849	$40,670
Scenario 14	*EXTEND PI*	$42,650	$37,367	$42,440	$42,878	$43,403	$45,104	$41,242	$44,416	$40,360
Scenario 15	*EXTEND All NUCLEAR*	$42,644	$37,443	$42,489	$42,799	$43,430	$45,080	$41,389	$44,219	$40,443

The numbers above represent 2020-2045 total NPV costs.

Table X-8: Strategist Net Present Value Deltas for Baseload Scenarios PVSC and PVRR, and Sensitivities B-I

Parent Run	Description	Base - PVSC	A-PVRR	B-Low Gas/Coal/ Markets	C-High Gas/Coal/ Markets	D-Low Load (High DER)	E-High Load (Electrification)	F-Low Resource Cost	G-High Resource Cost	I-Low Externality
Scenario 1	*REFERENCE*	$0	$0	$0	$0	$0	$0	$0	$0	$0
Scenario 2	*EARLY KING*	($78)	$105	($21)	($143)	($100)	($75)	($152)	($14)	($97)
Scenario 3	*EARLY SH3*	($23)	$353	$18	($87)	($66)	($70)	($210)	$236	$127
Scenario 4	*EARLY COAL*	($114)	$193	($115)	($112)	($97)	($134)	($280)	$116	($264)
Scenario 5	*EARLY MONTI*	$169	($34)	$79	$282	$109	$200	$196	$103	($37)
Scenario 6	*EARLY PI*	$587	$134	$407	$812	$512	$570	$474	$636	$92
Scenario 7	*EARLY All NUCLEAR*	$692	$95	$466	$966	$606	$681	$594	$715	$68
Scenario 8	*EARLY BASELOAD*	$445	$130	$187	$766	$404	$469	$309	$441	($348)
Scenario 9	*EARLY COAL; EXTEND MONTI*	($264)	$272	($128)	($455)	($276)	($269)	($203)	($338)	($123)
Scenario 10	*EARLY KING; EXTEND MONTI*	($138)	$202	$48	($389)	($141)	($146)	($77)	($171)	$40
Scenario 11	*EARLY COAL; EXTEND PI*	($537)	($62)	($402)	($737)	($554)	($587)	($513)	($569)	($509)
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	($668)	($25)	($438)	($999)	($667)	($691)	($397)	($1,042)	($416)
Scenario 13	*EXTEND MONTI*	($38)	$49	$19	($118)	($10)	($42)	$154	($245)	$66
Scenario 14	*EXTEND PI*	($431)	($257)	($296)	($638)	($419)	($453)	($226)	($678)	($243)
Scenario 15	*EXTEND All NUCLEAR*	($438)	($181)	($247)	($717)	($392)	($478)	($80)	($875)	($161)

The deltas above were derived by comparing the total NPV costs of each baseload scenario to the Reference Case/Scenario 1.

Table X-9: Strategist Net Present Value Results for Baseload Sensitivities J-U

Parent Run	Description	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs	P - Combo "DBF"	Q - Combo "ECF"	S - No Carbon Adder for Sales	U - Hourly Carbon, Retail Load Shape
Scenario 1	*REFERENCE*	$38,524	$41,016	$51,035	$37,447	$41,912	$43,203	$43,105	$43,006
Scenario 2	*EARLY KING*	$38,586	$40,997	$50,334	$37,548	$41,788	$43,002	$43,047	$42,924
Scenario 3	*EARLY SH3*	$38,815	$41,107	$50,567	$37,788	$41,846	$43,110	$43,033	$42,973
Scenario 4	*EARLY COAL*	$38,680	$40,980	$49,464	$37,622	$41,672	$42,893	$42,970	$42,890
Scenario 5	*EARLY MONTI*	$38,534	$41,105	$51,017	$37,401	$41,948	$43,459	$43,123	$43,174
Scenario 6	*EARLY PI*	$38,793	$41,429	$50,978	$37,578	$42,177	$43,832	$43,274	$43,588
Scenario 7	*EARLY All NUCLEAR*	$38,783	$41,476	$51,036	$37,527	$42,226	$43,882	$43,239	$43,690
Scenario 8	*EARLY BASELOAD*	$38,812	$41,302	$49,254	$37,570	$41,946	$43,543	$43,001	$43,434
Scenario 9	*EARLY COAL; EXTEND MONTI*	$38,687	$40,923	$49,813	$37,706	$41,791	$42,836	$42,961	$42,734
Scenario 10	*EARLY KING; EXTEND MONTI*	$38,629	$41,000	$50,619	$37,642	$41,989	$43,036	$43,144	$42,863
Scenario 11	*EARLY COAL; EXTEND PI*	$38,375	$40,624	$49,255	$37,369	$41,638	$42,488	$42,701	$42,463
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	$38,359	$40,564	$49,523	$37,413	$41,791	$42,440	$42,743	$42,319
Scenario 13	*EXTEND MONTI*	$38,535	$41,009	$51,201	$37,483	$42,295	$43,530	$43,203	$42,966
Scenario 14	*EXTEND PI*	$38,211	$40,652	$50,863	$37,183	$41,878	$42,790	$42,840	$42,571
Scenario 15	*EXTEND All NUCLEAR*	$38,257	$40,676	$50,982	$37,255	$42,173	$42,938	$42,992	$42,559

The numbers in the table above represent 2020-2045 total net present value (NPV) costs.

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Table X-10: Strategist Net Present Value Deltas for Baseload Sensitivities J-U

Parent Run	Description	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs	P - Combo "DBF"	Q - Combo "ECF"	S - No Carbon Adder for Sales	U - Hourly Carbon, Retail Load Shape
Scenario 1	*REFERENCE*	$0	$0	$0	$0	$0	$0	$0	$0
Scenario 2	*EARLY KING*	$62	($19)	($701)	$101	($124)	($201)	($59)	($83)
Scenario 3	*EARLY SH3*	$290	$91	($468)	$342	($65)	($93)	($72)	($33)
Scenario 4	*EARLY COAL*	$156	($36)	($1,571)	$176	($239)	($310)	($135)	($117)
Scenario 5	*EARLY MONTI*	$10	$89	($18)	($46)	$36	$256	$18	$168
Scenario 6	*EARLY PI*	$269	$413	($57)	$131	$265	$630	$169	$582
Scenario 7	*EARLY All NUCLEAR*	$258	$460	$1	$80	$314	$679	$134	$684
Scenario 8	*EARLY BASELOAD*	$288	$286	($1,781)	$124	$35	$340	($104)	$428
Scenario 9	*EARLY COAL; EXTEND MONTI*	$163	($93)	($1,221)	$260	($121)	($367)	($144)	($272)
Scenario 10	*EARLY KING; EXTEND MONTI*	$104	($16)	($416)	$195	$77	($167)	$39	($143)
Scenario 11	*EARLY COAL; EXTEND PI*	($150)	($392)	($1,780)	($78)	($274)	($714)	($404)	($544)
Scenario 12	*EARLY COAL; EXTEND All NUCLEAR*	($165)	($453)	($1,511)	($34)	($121)	($762)	($362)	($688)
Scenario 13	*EXTEND MONTI*	$10	($7)	$166	$36	$384	$327	$98	($40)
Scenario 14	*EXTEND PI*	($314)	($364)	($172)	($264)	($33)	($413)	($266)	($436)
Scenario 15	*EXTEND All NUCLEAR*	($267)	($340)	($53)	($192)	$261	($264)	($114)	($447)

The deltas in the table above were derived by comparing the total NPV costs of each baseload scenario to the Reference Case/Scenario 1.

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Table X-11: Strategist Net Present Value Results for North Dakota Scenario and Preferred Plan Sensitivities

Child Run	Description	Base - PVSC	A-PVRR	I-Low Externality	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs
Scenario 1	Supplement North Dakota Scenario		$37,061					
Scenario 9	Supplement North Dakota Scenario		$37,373					
Scenario 9	*EARLY COAL; EXTEND MONTI*	$42,818	$37,896	$40,481	$38,687	$40,923	$49,813	$37,706
Scenario 9	Wind Available 2023 @ $500/kW	$42,818	$37,896					
Scenario 9	Solar @ 50% ELCC Throughout	$42,806	$37,806					
Scenario 9	Sherco CC Alternatives - 7HA01 1x1	$42,869	$37,830	$40,299	$38,665	$40,925	$49,219	$37,638
Scenario 9	Sherco CC Alternatives - 7HA02 1x1	$42,772	$37,719	$40,246	$38,558	$40,826	$49,342	$37,537
Scenario 9	Sherco CC Alternatives - 7HA02 2x1	$42,922	$37,917	$40,534	$38,716	$40,994	$50,034	$37,713
Scenario 9	DSM/DR - Add DR Bundle 2	$42,840	$37,862	$40,424	$38,667	$40,921	$49,698	$37,665
Scenario 9	DSM/DR - Add EE Bundle 3	$43,559	$38,678	$41,230	$39,451	$41,676	$50,490	$38,476

The numbers in the table above represent 2020-2045 total NPV costs.

Table X-12: Strategist Net Present Value Deltas for North Dakota Scenario and Preferred Plan Sensitivities

Child Run	Description	Base - PVSC	A-PVRR	I-Low Externality	J-Low Externality, Low Regulatory	K-Mid Externality, Mid Regulatory	L-High Externality	M-No Reg or Externality Costs
Scenario 1	Supplement North Dakota Scenario		$0					
Scenario 9	Supplement North Dakota Scenario		$313					
Scenario 9	*EARLY COAL; EXTEND MONTI*	$0	$0	$0	$0	$0	$0	$0
Scenario 9	Wind Available 2023 @ $500/kW	$0	$0					
Scenario 9	Solar @ 50% ELCC Throughout	($11)	($90)					
Scenario 9	Sherco CC Alternatives - 7HA01 1x1	$51	($66)	($183)	($22)	$2	($594)	($68)
Scenario 9	Sherco CC Alternatives - 7HA02 1x1	($45)	($177)	($235)	($129)	($97)	($471)	($170)
Scenario 9	Sherco CC Alternatives - 7HA02 2x1	$105	$21	$53	$29	$71	$220	$6
Scenario 9	DSM/DR - Add DR Bundle 2	$22	($34)	($57)	($20)	($2)	($116)	($41)
Scenario 9	DSM/DR - Add EE Bundle 3	$742	$782	$749	$764	$753	$676	$770

The Supplement North Dakota Scenario deltas above were derived by comparing the total NPV costs of each scenario to Scenario 1 Supplement North Dakota Scenario. All other deltas were derived by comparing the total NPV costs of each Scenario 9 sensitivity to Scenario 9 – Early Coal; Extend Monti.

XI. SUPPLEMENT PREFERRED PLAN SENSITIVITIES – RELIABILITY ANALYSES

Traditional capacity expansion modeling that informs long-term resource planning optimizes selection of generating resource types based on their ability to meet projected system capacity needs in each planning year. As discussed in detail in Attachment A, Section VI: Resource Attributes, it is becoming increasingly important to also ensure that future resource portfolios provide the right mix of energy, capacity, and flexibility attributes when they are needed to ensure reliable service to customers.

This Supplement marks our first use of the EnCompass modeling tool, which allows for some level of energy and capacity adequacy testing subsequent to capacity expansion modeling. While we expect we will continue to learn and gain experience with EnCompass over time, we used its 8,760-hour modeling capabilities to perform some energy and capacity adequacy analysis. Time did not allow for comprehensive testing of all scenarios, sensitivities, and assumptions, so we focused our efforts on our Supplement Preferred Plan and a few sensitivity plans that are representative of futures with high proportions of variable resources. While our analysis was limited in scope, we believe the testing we performed provides valuable insights on energy and capacity adequacy in a highly renewable future by identifying plans – such as Scenario 9 – 50 percent ELCC – that are more likely to have energy adequacy issues. Additionally, we believe the testing we performed provides more evidence that our Supplement Preferred Plan will perform adequately under a variety of grid conditions.

A. Modeling Approach

Recognizing that we are moving to a future with less baseload, intermediate and peaking generation and more variable renewables, we selected four specific generation portfolios from the multitude of scenario and sensitivity options for detailed hourly testing. These four portfolios included our Supplement Preferred Plan – selected to confirm our Supplement Preferred Plan is reliable – and three Supplement Preferred Plan sensitivity portfolios. We selected the sensitivity portfolios – two Futures Scenarios and a sensitivity that tests holding solar capacity accreditation constant at 50 percent through the planning period – specifically because they included the lowest levels of firm dispatchable generation and thus highest levels of variable resources. See Table XI-1 below for a brief description of each of the capacity expansion plans included in our adequacy testing.

Table XI-1: Summary of Capacity Expansion Plans Selected for Energy and Capacity Adequacy Analysis

Capacity Expansion Plan	Description and Rationale for Testing
Scenario 9 - Supplement Preferred Plan	To ensure energy adequacy of the Supplement Preferred Plan under historical resource and load shape assumptions.
Scenario 9 – P (High Distributed Solar Future)	Scenario contains low technology cost assumptions, so the 2034 portfolio contains a relatively higher share of batteries and substantially less firm peaking generation than Scenario 9 under default assumptions.
Scenario 9 – Q (High Electrification Future)	Scenario contains low technology cost assumptions and high load, so the 2034 portfolio contains more capacity overall; primarily a high proportion of batteries and variable renewables and less firm peaking capacity than Scenario 9 using default assumptions.
Scenario 9 – 50 percent ELCC	Scenario assumes fixed 50 percent capacity credit for solar in all years, which significantly increases incremental solar additions and reduces firm peaking capacity selected but results in approximately the same amount of storage as Scenario 9 under default assumptions.

We summarize the adequacy testing process we used in Figure XI-1 below.

Figure XI-1: Energy and Capacity Adequacy Testing Process

Capacity Expansion Plan models → Identify optimal combinations of generation assets (Capacity Expansion Plans or CEP) given predetermined sets of constraints and assumptions

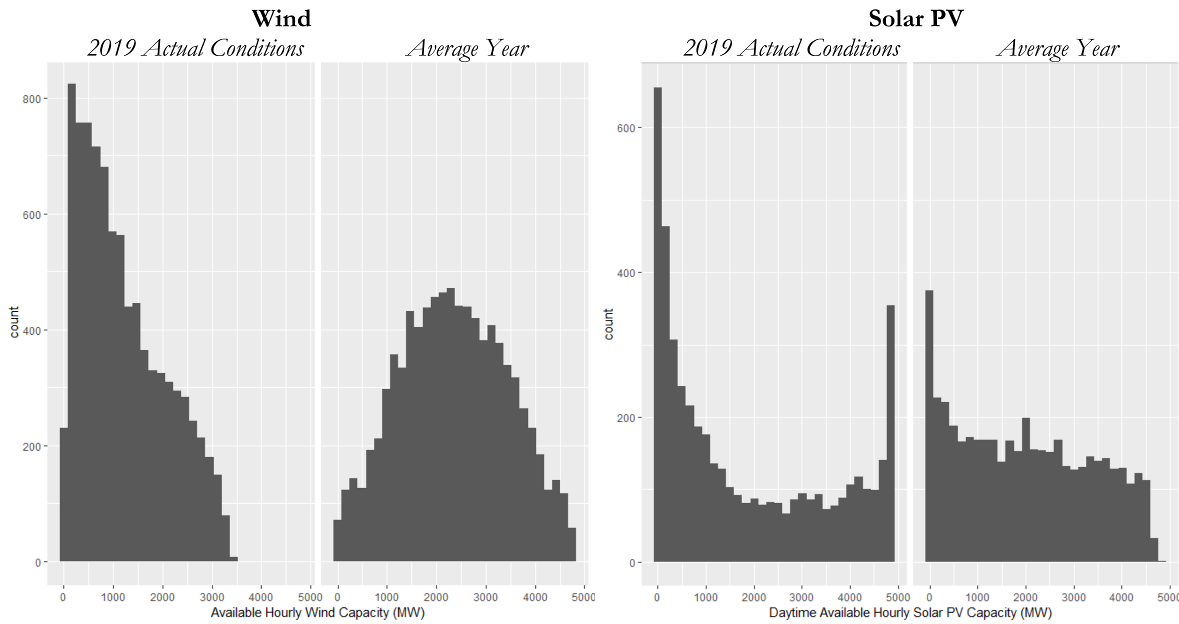
For each Capacity Expansion Plan → Dispatch the plan's selected generation assets in production cost models that assume a variety of historical conditions

For each Production Cost Model → Identify all periods where the Company lacks adequate resources to meet system needs

We tested the generation portfolios that resulted from the capacity expansion modeling for the four scenarios discussed above against a variety of actual historical conditions – using the EnCompass production cost model to identify whether there were periods of high reliability risk; in other words where customers' needs may outstrip the resources we have available to serve them under that specific future scenario. We used actual historical hourly load and renewable shapes from 2019 to simulate how each generation portfolio would have performed given actual weather history. Using this dataset allowed us to assess generation portfolios performance under recent actual historical grid conditions as opposed to the "average" year hourly load and renewable shapes used in the majority of our Supplement Resource Plan modeling.

We chose to use 2019 historical shapes because actual conditions can often be very different – and more challenging – than the averages otherwise used in our traditional capacity expansion and production cost modeling. To illustrate how different actual conditions can be from the averages, Figure XI-2 below shows actual hourly wind and solar PV generation profiles from the 2019 Actual Conditions compared to average wind and solar PV profiles used in capacity expansion modeling.

Figure XI-2: Histogram of Frequency of Hourly Production Levels – 2019 Actuals as Compared to Average Year Used for Capacity Expansion Modeling[80]



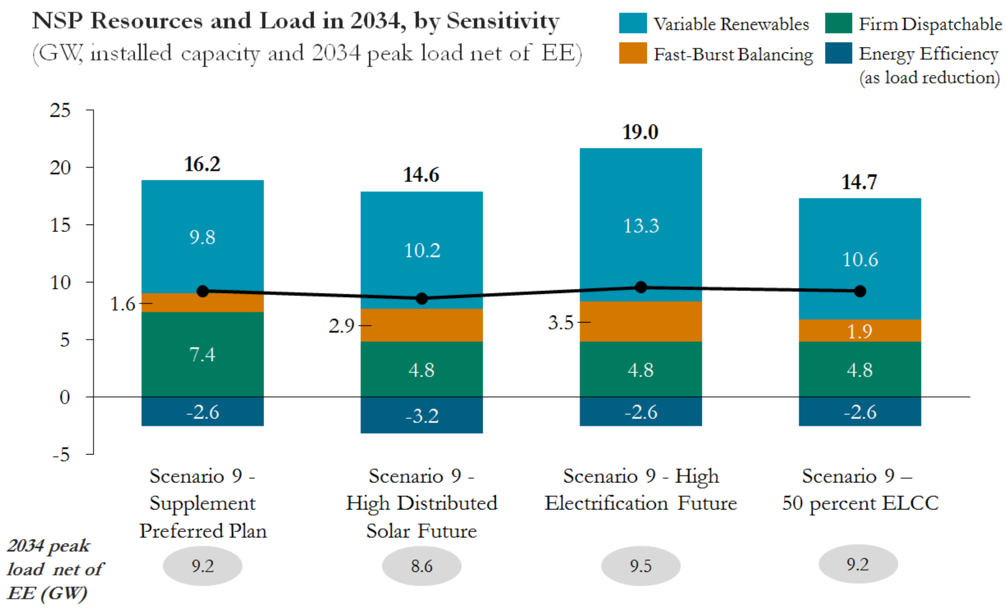
The findings of this analysis provided us with valuable insights about how reliably the four selected generation portfolios could meet system energy and capacity needs in 2034, if the plans faced the same pattern of hourly load and generation profiles seen in 2019.[81] We selected the year 2034 for the analysis because it is the final year of the planning period and thus is the year in which each portfolio had the least amount of firm dispatchable traditional capacity remaining. We did this by adjusting the 2019 Actual Conditions hourly renewable and load shapes to match the generation production and load levels of the renewables and load projected for each of the four portfolios in 2034.

We portray the full resource capacity mix for each of these generation portfolios in planning year 2034 in Figure XI-3 below. We have categorized the capacity into firm dispatchable,[82] fast burst balancing (which includes DR and battery storage), variable

[80] Figure XI-2 illustrates this comparison for the Scenario 9 – Supplement Preferred Plan.
[81] The actual 2019 hourly demand pattern was scaled to meet the 2034 projected peak load level for each scenario and the 2019 hourly generation profiles were applied to the wind and solar capacity in each plan tested. The shapes of the hourly demand and generation patterns are therefore preserved but appropriately scaled to reflect the anticipated level of demand and generation in 2034.
[82] For 2034, firm dispatchable includes nuclear, natural gas/oil, biomass, and hydroelectric resources.

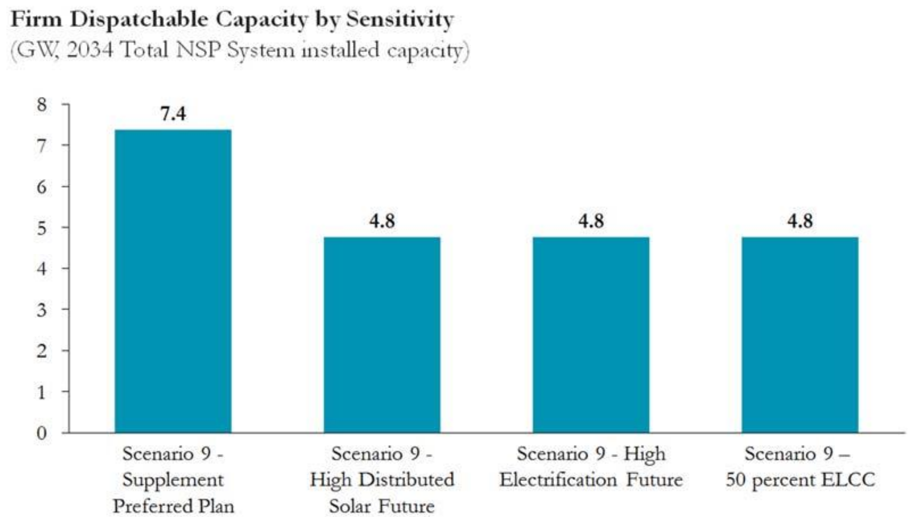
(which includes wind and solar) and EE. The chart clearly illustrates that the sensitivity portfolios are much more reliant on variable resources – having 35 percent less firm dispatchable capacity than the Supplement Preferred Plan.

Figure XI-3: Installed Capacity (ICAP) for each Tested Generation Portfolio (Total NSP System, 2034)



A distinguishing feature of the tested portfolios is the proportion of firm, dispatchable resources in relation to the Supplement Preferred Plan portfolio. Figure XI-4 below isolates and highlights the amount each portfolio contains in 2034.

Figure XI-4: Firm Dispatchable Capacity by Portfolio, Total 2034 NSP System Installed Capacity (ICAP)



The Supplement Preferred Plan includes more firm dispatchable capacity, with 7.4 gigawatts (GW), than the other three sensitivity scenarios which each only include 4.8 GW. As we discuss below, this is a primary contributor to the Supplement Preferred Plan's better reliability performance overall.

B. Adequacy Metrics Evaluated

Within the resource planning framework there are several ways to gauge the energy and capacity adequacy of a generation portfolio to help identify risks. This section describes metrics we used with this Supplement. We first illustrate the primary categories of adequacy metrics, then summarize the results for each capacity expansion model we tested. We also provide further technical descriptions as an addendum to this Attachment.

1. *Native Capacity Shortfall*

As discussed in Attachment A Section VI:Resource Attributes, we believe there is substantial risk to our ability to provide reliable service to our customers in some periods, were we forced to rely exclusively on MISO imports to meet a portion of our customers' needs. Most concerning are periods in which we do not own or have under contract, enough generation capacity to meet our full customer need. While we

– as members of MISO – should be able to rely on market purchases to an extent, these purchases are not firm resources, and thus there is no guarantee there will be sufficient market generation or import capacity available to lean on the market in all circumstances. Thus, we are interested in minimizing the number of hours in which we are unable to serve our own customer load due to insufficient native capacity, and the magnitude of those shortfalls.

Figure XI-5 below is an example of a shortfall in native capacity, or inability to fully serve our customers' needs with owned or contracted resources. These results were derived from the Scenario 9 – 50 percent ELCC generation portfolio and represent conditions faced on July 14-15 period in the 8,760-energy and capacity adequacy analysis.

Figure XI-5: Illustration of Native Capacity Shortfall – July 14-15, 2034 (Scenario 9 – 50 percent Solar ELCC)

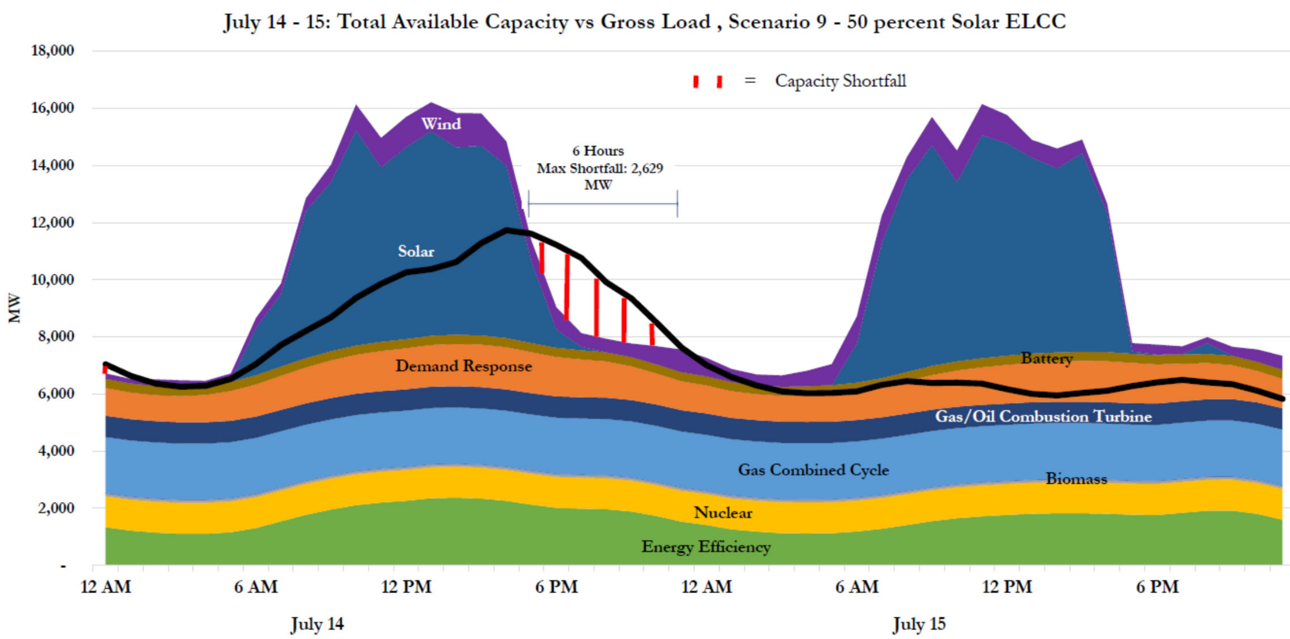


Figure XI-5 shows each type of available generation capacity for the specified scenario in each hour for the time period. The overlay of the Company's gross load – represented by the black line – shows any hours where we do not have sufficient native generating capability available. In this case, given this set of load and renewable generation patterns, we would not have sufficient native capacity available to meet customer needs, and therefore would need to rely on potential resource availability options in MISO in the evening hours of July 14.

2. *Flexible Resource Adequacy*

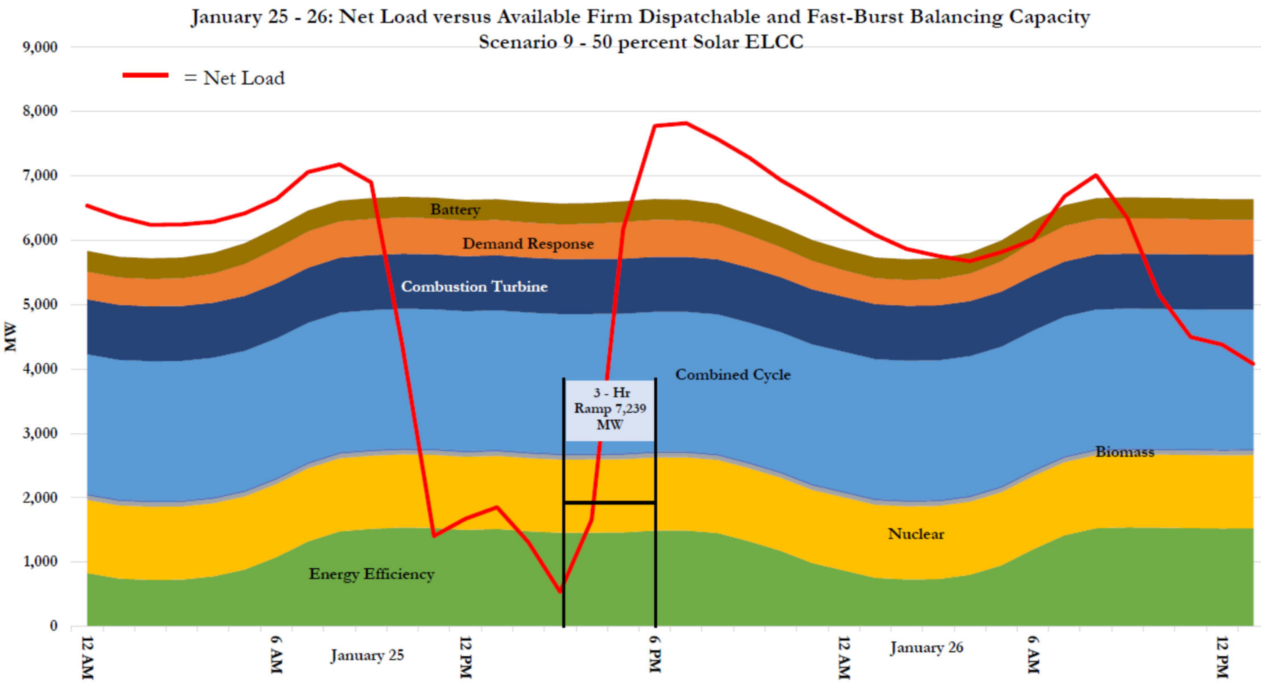
As discussed in Attachment A Section VI, flexibility is the capability of a resource to be ramped up or down relatively quickly in response to changes in customer demand. While MISO has not established Resource Adequacy measures for this capability, we sought out established metrics for inclusion in our adequacy testing. As part of its analysis on flexible resource adequacy, the California Independent System Operator (CAISO) identifies the maximum three-hour net load ramp – or the change in load minus generation from variable renewable resources– for each month.[83]

Using this metric, constraints occur at different times than many of the native capacity shortfalls discussed above – often during the spring and fall seasons, when load levels are lower and generation from renewable resources comprises a high amount of total generation. In these cases, rapid changes in the volume of renewable generation output can cause proportionally larger fluctuations in net system load. This results in grid challenges from an energy and capacity adequacy perspective in that: (1) it can compress the window of time in which significant changes in net load occur; and (2) it can magnify the size of net load ramp beyond the amount of firm dispatchable and fast-burst balancing resource capacity, causing additional native capacity shortfalls.

This effect is even more prominent in capacity expansion portfolios that have a high percentage of solar capacity. Figure XI-6 below shows an example of a rapid change in net load[84] (the solid red line) in a generation portfolio with high proportion of solar generation. Here, the generation output pattern for these days produce a rapid change in the amount of power generation from solar resources. Since solar comprises a large proportion of this capacity expansion plan, from 3:00 p.m. to 6:00 p.m. the net load changes very quickly; a 7,239 MW swing, in total. As seen in Figure XI-6, the Company would not – in this scenario –have enough firm dispatchable and fast-burst balancing capacity available in its portfolio to fully meet this rapid and large change in net load.

[83] Flexible Capacity Needs and Availability Assessment Hours Technical Study for 2020. California ISO, April 4, 2019.
[84] For a given hour, net load is demand minus the amount of generation from variable resources (wind and solar PV).

Figure XI-6: Illustration of High Three-Hour Net Load Ramp – January 25-26, 2034 (Scenario 9 – 50 percent ELCC)



In comparison, capacity expansion plans with higher proportions of firm dispatchable capacity do not experience this magnitude of net load ramp during the same time period. For example, the maximum three-hour net load ramp is 4,822 MW in the Supplement Preferred Plan when tested using the same conditions for the same time period. Not only is the ramp smaller in magnitude with the Supplement Preferred Plan, the amount of available resources capable of providing flexibility and balancing attributes to the grid are sufficient to meet the full ramp amount.

In general, this piece of our analysis finds that capacity expansion plans with low amounts of flexibility-supporting resources on days in which weather conditions produce rapid changes in the amount of solar and wind generation output create risk for our system. In those cases, our analysis shows that we would need to rely on external resources from MISO on these days, which introduces availability risk; especially if other load serving entities in our region similarly lean on the market during these hours as discussed further below. To be clear, as a member of MISO, we should rely on market purchases when other MISO resources can serve our load cheaper than our own. However, when we must rely on MISO resources because we do not have adequate capacity to serve our load on an hourly basis, we are exposed to uncapped market risk because we do not have a resource hedge to mitigate our exposure.

3. *Maximum Import Assessment*

Most of the metrics in this analysis focus on potential outages and unserved energy needs. However, we have also quantified the number of hours each Scenario assumes that the Company relies on a high level of MISO imports – at least 95 percent of the current 2,300 MW-h maximum (2,185 MW-h) of imports or greater. This analysis highlights periods in which we are heavily reliant on external resources from MISO. As indicated in Attachment A Section VI, the maximum amount of external capacity we can rely on may, in reality, vary during different seasons – as our share of total network load varies by season – and with different sets of regional grid conditions. Minimizing the number of hours where we would require the maximum MISO import capability, therefore, reduces our risk of being unable to provide reliable service to our customers.

4. *Industry Metrics*

MISO, NERC, and others in the electric industry have additional methods of characterizing capacity and energy shortfalls, including Loss of Load Hours (LOLH), Loss of Load Equivalent (LOLE), and Expected Unserved Energy (EUE). EnCompass automatically calculates these metrics, and we include the results of these for each scenario tested in Table XI-2 below. The main difference between these and the Native Capacity Shortfall and Flexible Resource Adequacy metrics discussed above is that these *automatically* incorporate the current maximum power import capability from MISO (2,300 MW per hour) into the calculation to determine whether enough resources exist to serve customer load, rather than allowing us to examine the extent of the potential deficit. Due to the limited amount of time we had to develop our models with EnCompass, we modeled a fixed level of MISO import capability in the analysis. That said, we believe automatic inclusion of a fixed level of MISO import capability may undermine the relevance of EnCompass model results for these industry metrics, because MISO import capabilities vary over time, and there is no guarantee the maximum import capability will be available to the Company when it is needed. As we conduct additional adequacy testing in the future, we will investigate assumptions about import capability and its impact on energy and capacity adequacy in more detail.

5. *Summary of Findings*

Table XI-2 summarizes the results of this analysis from the stress conditions we applied to the capacity expansion Scenarios tested.

Table XI-2: Energy and Capacity Adequacy Metrics for Tested Expansion Plan Scenarios

	Native Capacity Shortfall Metrics					Flexible Resource Adequacy Metric	Maximum Import Metric	Industry Metrics		
Expansion Plan (Test Dataset in Parentheses)	**# of Native Capacity Shortfall Events**	**Average Duration of Shortfall Events (hours)**	**Average Intensity of Capacity Shortfall (MW)**	**Longest Shortfall Event (hours)**	**Peak Capacity Shortfall During 2034 (MW)**	**Maximum 3 – Hour Upward Ramp (MW)**	**# of Hours with High Imports**	**LOLH (Hours)**	**LOLE (Days)**	**EUE (MWH)**
Baseline – Scenario 9 - Supplement Preferred Plan (Default)	0	0	0	0	0	4,760 (February)	9	0	0	0
Scenario 9 - Supplement Preferred Plan (2019)	4	1.75	363	2	615	5,506 (June)	158	0	0	0
Scenario 9 – High Distributed Solar Future (2019)	14	2.57	481	5	1,232	7,221 (June)	157	0	0	0
Scenario 9 – High Electrification Future (2019)	21	2.00	429	6	1,037	7,152 (March)	674	0	0	0
Scenario 9 – 50 percent ELCC (2019)	159	3.97	604	22	2,629	7,239 (January)	311	5 (2 separate events)	2	2,575

Note: *The expansion plan with the greatest shortfall is shown in red font for each metric.*

C. Comparison of Plans for a Stress Week

In addition to comparing the results outlined in Table XI-2 above, we provide, as Figures XI-7 through XI-10, a snapshot of each tested Scenario's capacity expansion plan for a "stress week" over December 5-10, 2034 – again using actual customer load and renewable generation patterns from 2019. Seeing how each capacity expansion portfolio is expected to serve a historically observed load pattern provides additional perspective on the types of energy and capacity adequacy gaps that are likely, and the types of resources that would help mitigate such gaps and shortfalls.

The only generation portfolio tested with no native capacity shortfalls during this stress week is the Supplement Preferred Plan. Two of the other plans: (1) Scenario 9 – High Distributed Solar Future; and (2) 9 – High Electrification Future, have small capacity shortfalls that could be served by external resources from MISO, if available, or additional native fast-burst balancing or flexible sources. One scenario (Scenario 9 – 50 percent ELCC) has a substantial number of shortfalls and requires a large degree of reliance on external MISO resources or substantial additions in native firm capacity.

Figure XI-7: Stress Week Assessment: Scenario 9 - Supplement Preferred Plan

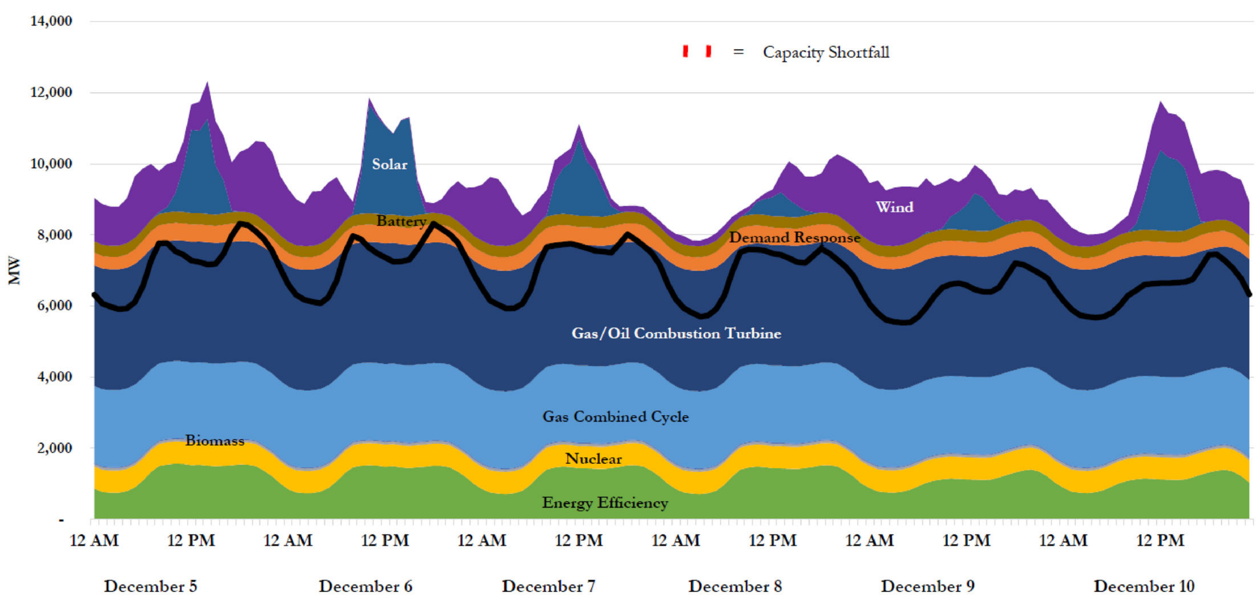


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Figure XI-8: Stress Week Assessment: Scenario 9 – High Distributed Solar Future

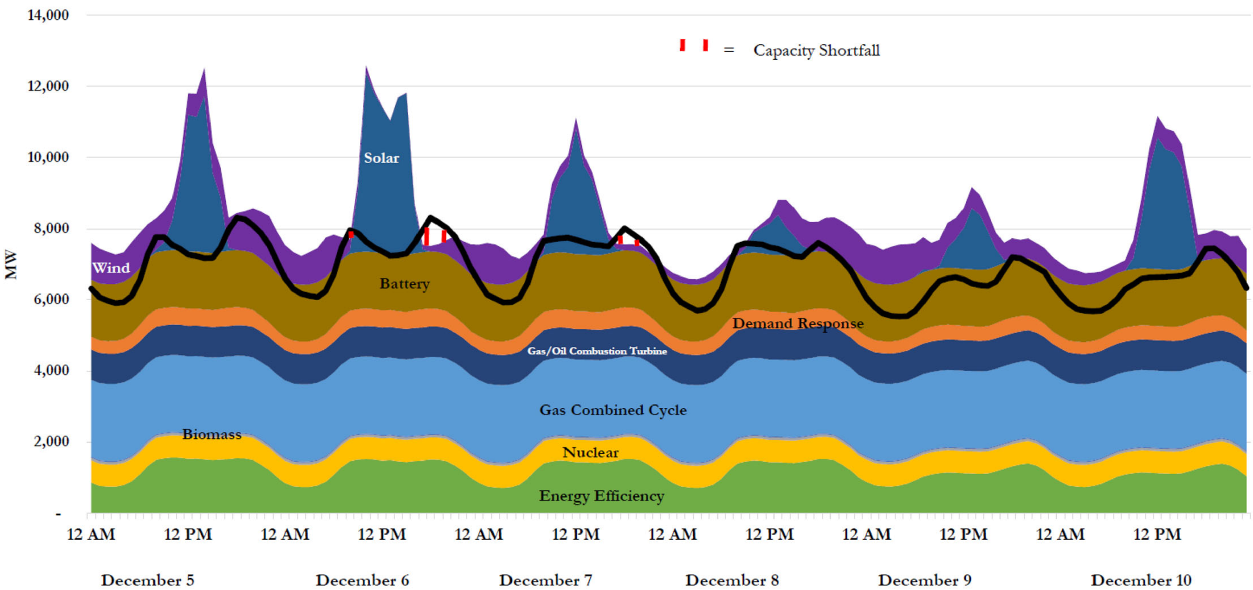


Figure XI-9: Stress Week Assessment: Scenario 9 – High Electrification Future

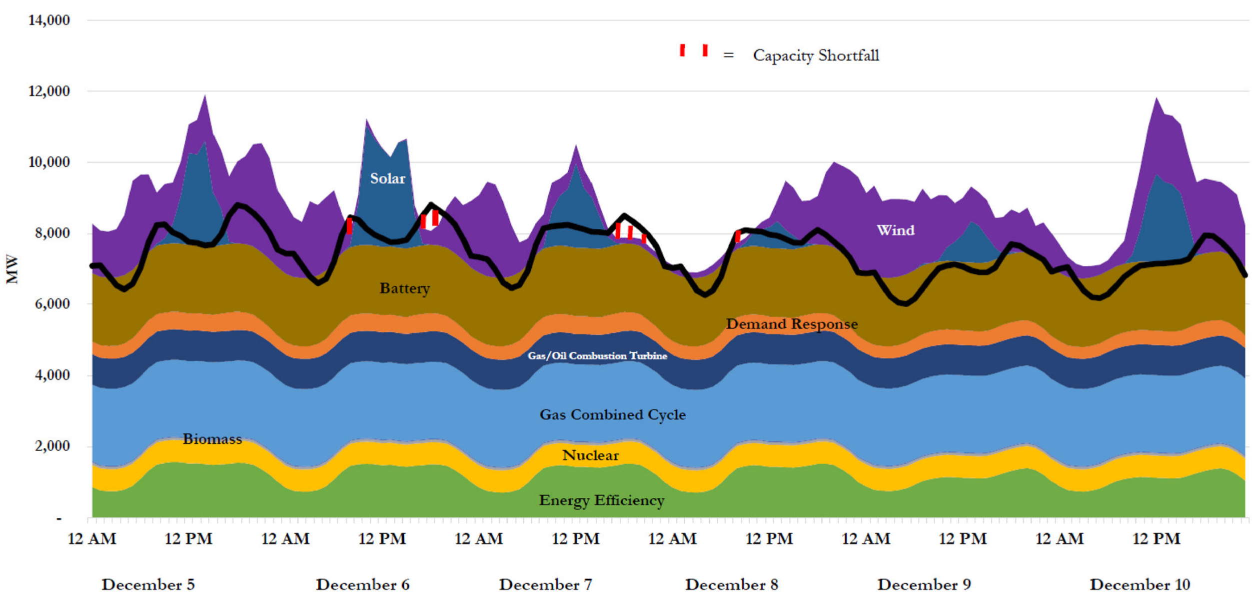
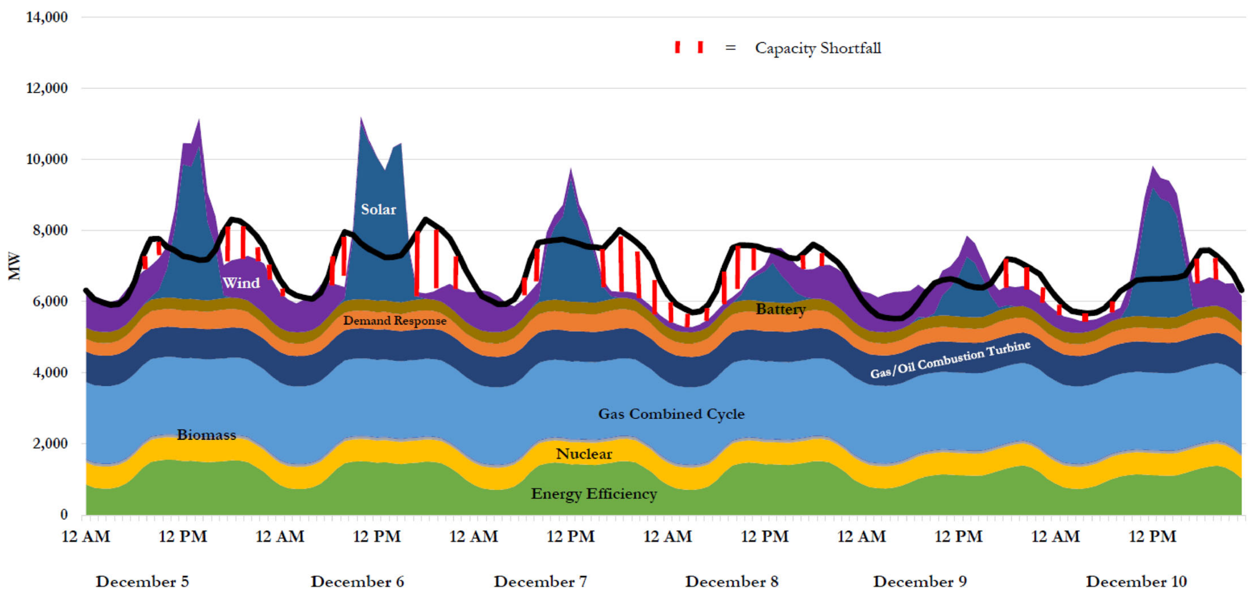


Figure XI-10: Stress Week Assessment: Scenario 9 – 50 percent Solar ELCC



As our system continues to evolve and transition further to include increasingly higher levels of variable resources, robust analyses, which likely include additional years of renewable and load shape history, will be needed to explore which shortfalls can be reliably addressed with fast-burst balancing resources such as demand response and batteries, versus firm dispatchable resources.

D. Limitations

It is important to note that we were only able to test a few capacity expansion plans prior to the filing of this Supplement. Energy and capacity adequacy testing cannot start until we have a set of completed expansion plans and production cost models from the capacity expansion modeling process, and the process of transitioning to the completely new EnCompass software and developing the initial capacity expansion plans and production cost models was time and effort intensive. Further, adequacy testing is a time-intensive analysis process that involves examining hourly-level production cost modeling data across the several key dimensions discussed above. Consequently, while we believe the energy and capacity adequacy testing we performed provides valuable insights, time did not allow for more comprehensive testing of additional scenarios and sensitivities, or incorporating additional years of historical data by which to simulate portfolios' performance against load and renewable shapes.

E. Summary and Conclusion

While we continue to develop a full understanding of all of the EnCompass model's energy and capacity adequacy analyses capabilities, the above findings indicate risks associated with portfolios that rely more heavily on variable renewables and use-limited resources. As demonstrated in Table XI-2 above, the Supplement Preferred Plan exhibits few to no issues under the typical conditions that were used as a default assumption for baseload scenario modeling. When evaluated under the 2019 actual historical conditions, we encountered more periods in which native capacity is not sufficient to serve our customers – and our import capabilities were at maximum levels; but these events were still relatively uncommon.

The three sensitivity portfolios produce more adequacy challenges when evaluated under the 2019 actual shapes, either with the magnitude or length of native capacity shortfalls, 3-hour ramping needs, or others. In particular, the "Scenario 9 – 50 Percent ELCC" portfolio experiences the highest number and duration of native load shortfalls, and a high 3-hour ramp. We believe this evaluation helps to confirm that our use of a declining ELCC metric for solar is appropriate. We also note that the longest shortfall duration in this test scenario far exceeds the capability of a four-hour battery to mitigate and indicates further examination regarding a 100 percent ELCC assumption for battery energy storage is warranted.

In conclusion, we believe these results reinforce the importance of assessing our system's adequacy from an hourly energy and capacity perspective as we retire coal units and add renewables. We will continue to develop our approach to energy and capacity adequacy analyses using EnCompass in the future. That said, when evaluating our full body of modeling results, including these results, we believe they support the conclusion that Scenario 9 is an appropriate choice to form the basis of our Supplement Preferred Plan.

Reference: Definitions of Key Terms and Metrics

Native Capacity Shortfall = The amount of NSP System load that is above and beyond the available capacity from owned and contracted resources for a given hour:

Load > Available Capacity

Average Duration of Shortfall Events = Average number of hours per Native Capacity Shortfall Event

Average Intensity of Capacity Shortfall = The peak amount of capacity needed during each event, on average, to avoid a native capacity shortfall.

EUE = Expected Unserved Energy (MWh) is total amount of energy that could not be served.

Longest Shortfall Event = The length, in hours, of the longest event where a native capacity shortfall occurred.

LOLE = Loss of Load Expectation is the number of days that experienced a loss-of-load event (LOLH > 0).

LOLH = Loss of Load Hours is the number of hours in which load exceeds available generation and import capability.

Maximum 3-Hour Upward Ramp = The maximum upward change in net load over a continuous three-hour period.

Net Load = Load minus generation from variable renewable resources (wind and solar PV)

# of Hours with High Imports = The numbers of hours in each scenario where the amount of market purchases required to serve customer load was at or over 95 percent of the system maximum import limit of 2,300 MW-h.

Peak Capacity Shortfall during 2034 = The maximum native capacity shortfall, in MW, per each scenario tested.

XII. CUSTOMER RATE & BILL IMPACTS

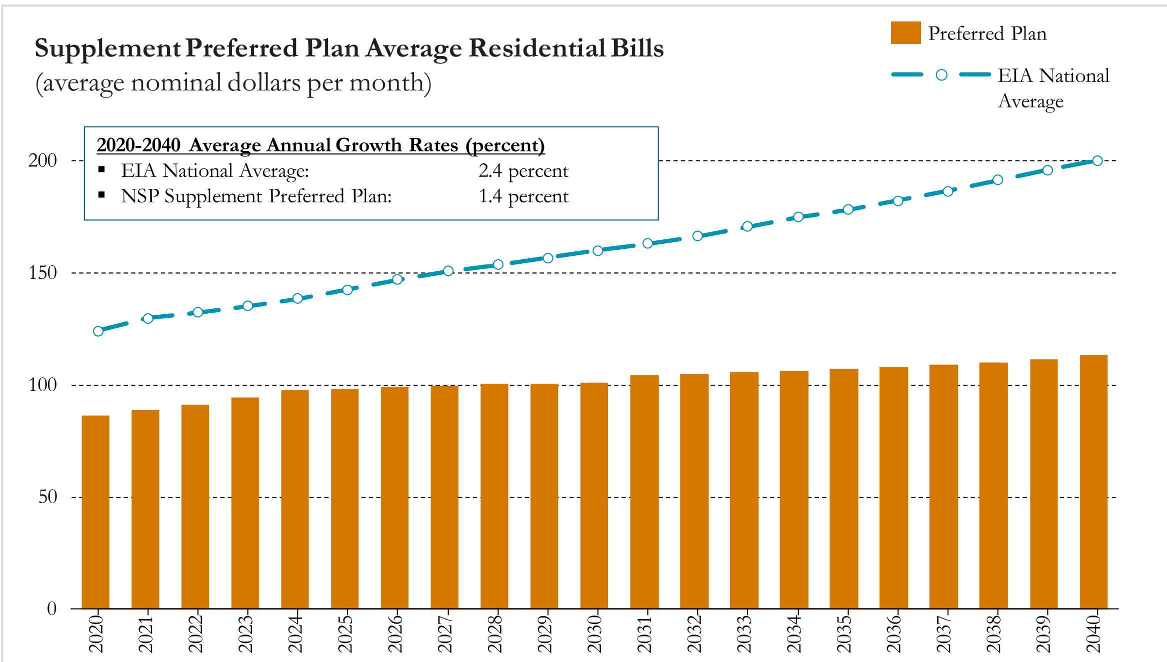
Minn. R. 7843.0500, subp. 3, requires the Commission to evaluate resource plans on, among other things, their ability to "keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints." Our July 2019 initial filing included a customer cost analysis that showed our Preferred Plan achieved our carbon goals and reliability objectives while maintaining affordability. While our methodology and approach to calculating customer cost impacts has remained largely the same in this Supplement, there are several fundamental changes to modeling inputs and approaches that lead us to an updated view of our Supplement Preferred Plan's customer cost impacts. Specifically, we are now using EnCompass model outputs, rather than the legacy Strategist model's outputs, for our analyses and we have refreshed many of our modeling inputs and assumptions to incorporate the latest available data. These changes, and the resulting differences in capacity additions and system dispatch, result in changes in our overall assumed revenue requirements and sales.

Our refreshed customer cost impact analysis finds that our Supplement Preferred Plan continues to keep average residential customer bills well below the national average. Additionally, our projected average bill and rate growth remains below inflation and is nearly a full percentage point below national averages for bill and rate growth. That said, we do note that the Supplement Preferred Plan projects slightly higher rates, when compared to our initial filing and national average rate estimates, and we discuss key drivers of these differences below. When reviewed as a whole, however, we believe these metrics show that our Supplement Preferred Plan maintains affordability while achieving substantial carbon reduction benefits relative to our Supplement Reference Case, and that it keeps customer bills and our rates as low as practicable.

A. Residential Bill Analysis

Energy efficiency (EE) is a cost-effective part of our future plans on a system-wide basis; and it contributes to keeping average customer bills low. However, as discussed further below, our plans to increase EE achievements over the next several years is one key driver of upward pressure on our electricity rates. As a result, we believe it is important to begin examining our Supplement Preferred Plan's customer cost impacts by reviewing the effects on an average residential bill. As shown in the Figure below, NSP System residential customers – on average – pay substantially less per month than the national average. In the early years of the forecast, this difference is attributable to lower than average electricity consumption, driven partially by our anticipated EE achievements (because when energy sales are reduced, the same level of fixed costs are spread over fewer kilowatt hours (kWh)). We also expect our average bill levels will grow more slowly than the national average, by approximately a full percentage point per year.

Figure XII-1: Systemwide Supplement Preferred Plan Average Residential Bills



That said, we acknowledge that there can be wide variation in customers' ease of access EE measures that will help flatten effects of rate increases going forward. We note that, in our Relief and Recovery Plan filed with the Commission in response to the COVID-19 pandemic (in Docket No. E,G999/CI-20-492), we are proposing several investments to better reach low-income customers with EE benefits.[85]

B. Rate Impacts and Key Drivers

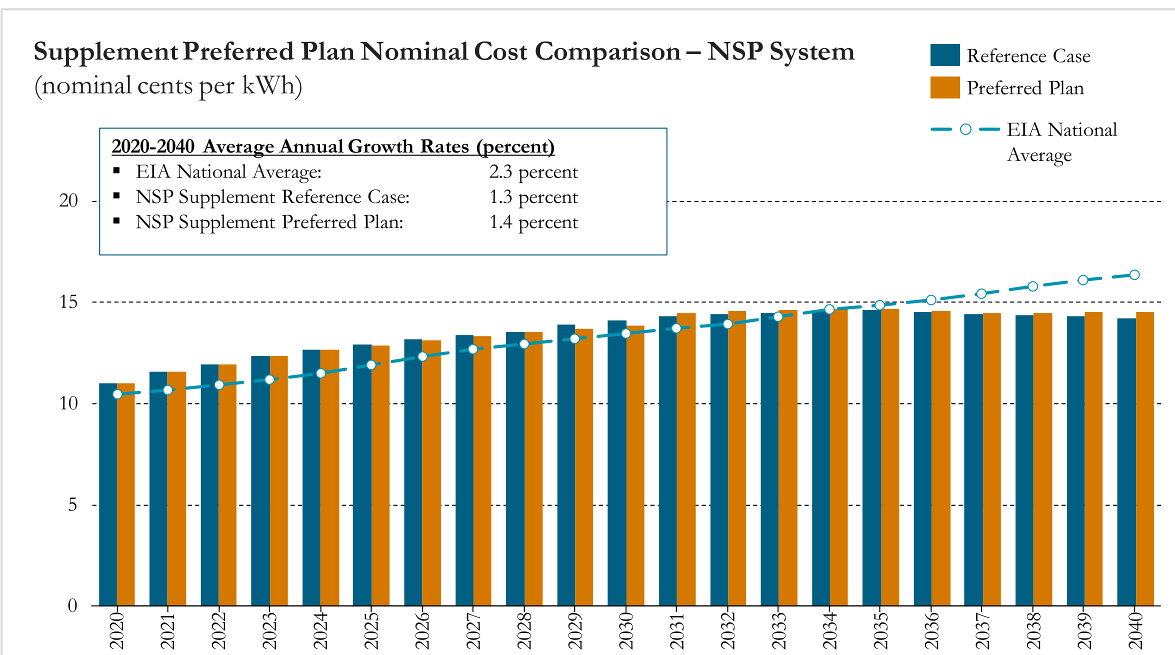
In addition to reviewing average residential bill impacts, we believe it is important to consider the impacts of the Supplement Preferred Plan on our rates. In this Section, we discuss the Supplement Preferred Plan's forecasted cost impacts relative to the updated Reference Case, as well as changes relative to our initial July 2019 filing. Overall, our Supplement Preferred Plan results in slightly higher rates as compared to

[85] *See* Docket No. E,G999/CI-20-492. COVID-19 RELIEF AND RECOVERY REPORT (June 17, 2020) at 17-18.

the updated Reference Case, although they are similar in most years of the analysis. This finding is consistent with the relatively low, but positive, delta between the PVRR for Scenario 9 as compared to the Reference Case presented in Section II: Modeling Framework and Results[86].

We project that the Supplement Preferred Plan would result in rate increases of approximately 1.4 percent per year through 2040 as compared to the updated Reference Case growth rate of 1.3 percent, on a system-wide basis. We note that this estimated rate increase, on an average annual basis, is nearly one percentage point lower than the national average rate increase, as projected by the Energy Information Administration (EIA),[87] and lower than the rate of inflation. In other words, we can achieve the Supplement Preferred Plan's significant carbon emissions reductions with cost impacts that are significantly less than expected national average increase in electricity prices. This rate of increase is also less than the rate of inflation.

Figure XII-2: Systemwide Supplement Preferred Plan Nominal Cost Comparison



[86] We note that once externality and regulatory costs of carbon are factored in, the Supplement Preferred Plan results in present value societal benefits relative to the updated Reference Case, but these are not factored into rate or bill analysis.
[87] See Energy Information Administration. *Annual Energy Outlook 2020.* (January 2020). Available at: https://www.eia.gov/outlooks/aeo/index.php

Relative to our July 2019 filing, our estimated average rates are slightly higher in this Supplement, and they remain above the updated national average further into the forecast period. There are three key contributing factors to differences between our initial filing's rate impact analysis and the Supplement findings.

First, our sales estimates – in both the updated Reference Case and Supplement Preferred Plan – decreased relative to the forecasts used in our initial filing. As noted above, the estimated decline in sales is primarily attributed to an increase in levels of EE assumed in our underlying demand forecasts, which is partially offset by higher projected electric vehicle electricity consumption in the latter years of the forecast period. As a result of sales declines attributable to EE, the total revenue requirements for both the Reference and Preferred Plans are spread over fewer kWh sales, and the rates needed to recover the required revenue increase.

Second, we note that our total revenue requirements have increased relative to our initial filing. Some of the difference is attributable to Strategist and EnCompass being fundamentally different models that handle market dispatch differently. However, we observe that the largest changes in cost factors between the July 2019 filing and this Supplement include increased fixed costs from renewable capacity expansion and increased fuel and variable operating and maintenance (O&M) costs, with increases in market interaction benefits partially offsetting those cost drivers. The Supplement Preferred Plan includes more renewable capacity additions than our initial Preferred Plan, and although cost assumptions for some renewable technologies have declined – as a result of projected technology improvements – the increase in capacity additions results in somewhat higher revenuer requirements overall. Further, variable O&M costs increase overall, partially as a result of the costs of operating more capacity, and partially because the Strategist modeling used as the basis of our revenue requirements analysis in the initial filing did not account for startup and other hourly operational costs that the EnCompass model does capture. These upward pressures are offset somewhat by the Supplement Preferred Plan's market interactions, which result in more savings than in our initial Plan.

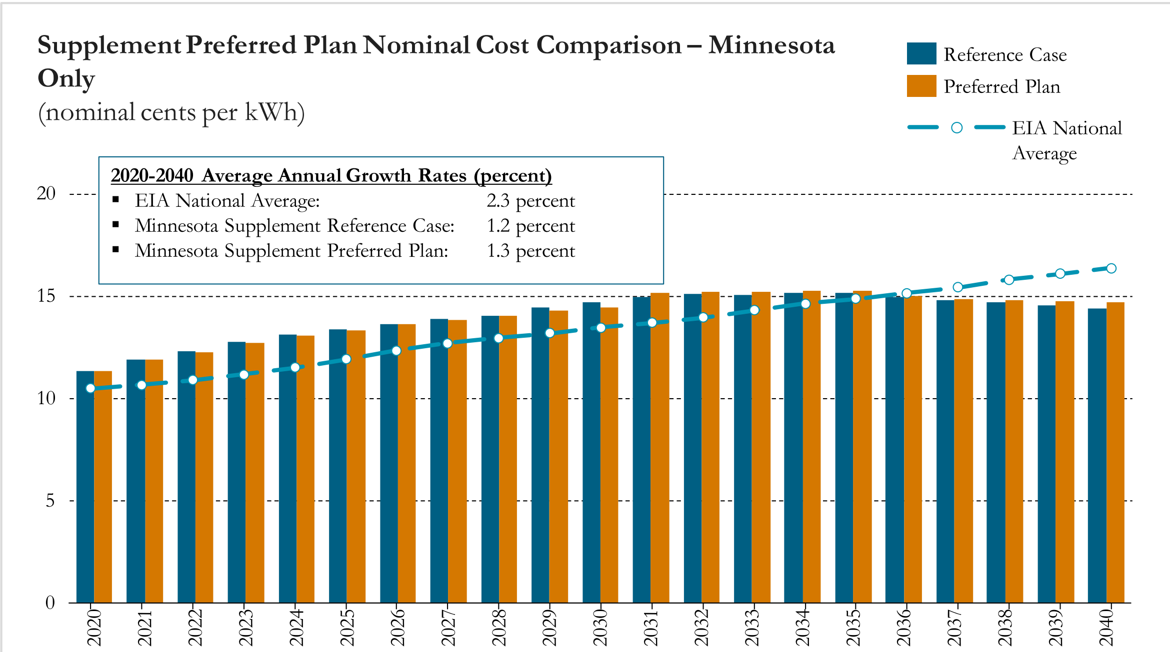
Third, we note that the EIA's 2020 projection of national average nominal electricity rates has declined – both in terms of the rate level and the pace of expected future growth – relative to the 2019 vintage we used in our initial filing. EIA's *2020 Annual Energy Outlook* (AEO) notes that average customer rates declined primarily as a result of declining technology costs and lower natural gas price forecasts relative to the assumptions used in the 2019 AEO.[88] EIA notes that its price forecasts are very sensitive to these factors, and especially natural gas price trends. This change lowers the estimated benchmark of national prices against which we compare our Supplement Preferred Plan.

When considered altogether, these three factors contribute to our findings that the Supplement Preferred Plan increases forecasted rates relative to our initial filing and are expected to be somewhat higher than the national average in the near term. However, it is also important to note that our Supplement Preferred Plan still results in estimated rate growth that remains well below – by nearly a full percentage point – EIA's estimated national average rate of growth of 2.3 percent per year, while it achieves substantial carbon reduction relative to current system levels and the updated Reference Plan.

When we look at the Minnesota customers-only projected rate impact, the factors discussed above remain. This is primarily because nearly all of the estimated EE effects – which place upward pressure on rates – are attributed to Minnesota customer adoption. That said, the average annual growth projected for Minnesota-specific rates is marginally lower than the NSP System overall. This is driven by more growth in the underlying energy sales forecasts relative to the system overall, which spreads Minnesota-specific revenue requirements over a broader base of consumption. Again here, we note that the expected growth rate attributable to the Supplement Preferred Plan is substantially lower than expected national average rate growth.

[88] See Energy Information Administration. *Annual Energy Outlook 2020 - Electricity.* (January 2020), at slide 25. Available at: https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Electricity.pdf

Figure XII-3: Minnesota Customers Supplement Preferred Plan Nominal Cost Comparison



Based on the totality of these metrics, we believe our Supplement Preferred Plan keeps customer bills and rates as low as practicable while achieving the substantial carbon reduction benefits we anticipate as a result of the plan.

XIII. UPDATED DEMAND RESPONSE FIVE-YEAR ACTION PLAN

Our Supplement Preferred Plan includes 1,349 MW of demand response resources by 2023. This amount of demand response resources includes a net incremental load increase of 469 MW (453 Gen. MW) compared to our 2017 baseline of 880 MW, meeting the requirements of the Commission's Order to obtain an additional 400 MWs by 2023.[89]

There are a few changes between our initial filing and this Supplement worth noting. Most notably, our Supplement Preferred Plan has increased the amount of demand response added through 2023 from 391 Gen. MW in the initial Preferred Plan to 453 Gen. MW. This increase is largely due to an increase in the base forecast of demand response beginning in 2020 due to a higher load forecast for existing interruptible rates.[90]

The following was also changed:

- Our base forecast now includes a category for Residential Demand Response, which includes both our Saver's Switch program as well as the AC Rewards program. This change aligns our base forecast with the demand response we register with MISO but adjusts the original categorization of these programs; and,
- We have increased the forecast for Small Business Thermostats based on the success of our pilot and approval by the Department of Commerce.[91]

Finally, we note that our forecasts for demand response included in the Supplement Preferred Plan were based on data captured prior to the COVID-19 pandemic emerging in Minnesota. How the pandemic will impact our demand management portfolio moving forward is currently unknown. We continue to believe, however, that we have laid out the best path to achieve additions of 400 MW of demand

[89] As discussed on page 26 of the Brattle Group Study included as Appendix G2 to the July 2019 filing, the Company has interpreted the Commission's Order to require 400 MW of capacity-equivalent DR, which is a greater value than MW of offset generation, because it incorporates the planning reserve requirement. 469 MW measured as a capacity-equivalent value is equivalent to 453 MW measured as a generator-level value ((469/1.089)/0.95) where the reserve margin is 8.9 percent and the coincident factor is estimated at 95 percent for all existing and potential programs. In this Appendix, we refer to MW measured at the generator-level as Gen. MW.

[90] As noted below, this forecast likely will need to be revisited in light of COVID-19.

[91] February 21, 2020. Decision, *In the Matter of Xcel Energy's Program Modification Request Filed December 23, 2019*, Minnesota Department of Commerce, Docket No. E,G002/CIP-16-115.

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response by 2023. In Table XIII-1, below, we lay out our plan for making these additions.

Table XIII-1: Demand Response Five-Year Action Plan

						Estimated Cumulative Potential (Gen. MW)			
	Program	**Regulatory Path**	**Program Status**	**2017 (Baseline)**	**2019**	**2020**	**2021**	**2022**	**2023**
Existing Programs	Electric Rate Savings	CIP (admin); Rate Case (discounts)	Existing	503	461	518	519	520	522
	Residential Demand Response (Including Saver's Switch and AC Rewards)	CIP (admin); Rate Case (discounts)	Existing	348	436	460	474	487	498
	AC Rewards (Smart Thermostats) - Incremental Growth above existing projections	CIP	Existing	-	-	14	59	60	61
	Peak Partner Rewards	CIP	Existing	-	-	15	42	45	45
	Small Business Smart Thermostats	CIP	Existing	-	-	3	4	5	9
	Subtotal Existing			**851**	**897**	**1,010**	**1,098**	**1,117**	**1,135**
New Programs	Two-way communication switches - Saver's Switch Technology Update	CIP	2021-2023 Triennial Plan Filing	-	-	-	-	-	19
	Interruptible Tariff(s)	Miscellaneous Filing	Tariff Filing Fall 2020	-	-	-	40	90	115
	Subtotal New			-	-	**-**	**40**	**90**	**134**
Non-Traditional Programs	Grid Enabled Electric Water Heaters	Non-Traditional - TBD	In design, partially allowed as part of Saver's Switch	-	-	-	4	9	13
	Commercial Building Controls (Auto DR)	Non-Traditional - TBD	In design - Currently not cost-effective	-	-	-	10	15	22
	Other	Non-Traditional - TBD	Various programs in design	-	-	-	-	-	-
	Subtotal - Non-Traditional			-	**-**	**-**	**14**	**24**	**35**
	Total Existing, New and Non-Traditional Programs			**851**	**897**	**1,010**	**1,152**	**1,230**	**1,304**
	Incremental Program Capacity (Gen. MW)			**0**	**46**[92]	**159**	**301**	**379**	**453**
	Incremental Program Capacity with Reserve Margin (MW)								**469**

[92] We note that, we saw a drop in controllable load in 2018 of 27 Gen. MW, due to both attrition and a result of a change in our methodology for calculating interruptible demand calculations that was more useful to the Midcontinent Independent System Operator. We have since seen expansion of our programs by a net increase of load of 46 Gen. MW and a total incremental increase of 73 Gen. MW compared to the 2017 baseline.

A. Incremental Growth of Demand Response

Since 2018, we have increased demand response resources by 73 Gen. MW solely through growth in our existing programs. To achieve the 400 MW addition, however, we are doing more than just adding customers to the programs we already have. In 2020, we launched two new demand response programs: Peak Partner Rewards and AC Rewards Small Business. In addition, we continue to expand our AC Rewards Residential program in other parts of our NSP System service area, including in both Wisconsin and South Dakota. We have also begun pilots across our territory determining the interest in newer technologies such as air-source heat pumps, grid-operated electric water heaters, and rates combined with behavioral demand response. Many of these efforts are occurring in our Colorado service territory due to the ability to utilize active smart meter technology and cost-recovery mechanisms already put into place for these types of efforts. These pilots will continue to expand our reach to customers interested in decreasing their load during certain times of the day or during a control event launched by the Company.

1. *New Programs*

Initially, we have focused our incremental growth on opportunities for customers in the mid-market segment, which has been the most underserved by existing demand response opportunities. In order to meet this segment's needs, we launched two new options for the 2020 summer control season: Peak Partner Rewards (PPR) and AC Rewards for Business.

PPR, launched in March 2020, is a new program which offers bill credits and access to electric load profile data to business customers that agree to reduce their electrical loads when the electric grid experiences peak demand periods. The program's incentive structure emphasizes actual performance during control periods. These incentives are provided through our Conservation Improvement Program (CIP), and savings are identified through electric load profile data. Our account managers are currently engaged with data centers, schools, and several other commercial and industrial customers who have expressed interest in participating in the program.
AC Rewards for Business expands our existing AC Rewards program into the commercial space, through direct installation of smart thermostats. Customers receive a smart thermostat for free through the program, in addition to a $25 bill credit for participating in demand response. AC Rewards started as a pilot program with 400 enrollees in 2019 and officially launched under the Saver's Switch for Business program beginning in May 2020. The speed with which we were able to transition from a pilot to a full launch is a result of early customer engagement.

2. *Programs in Development*

We continue to work towards developing new products and opportunities for customer demand response participation through expansion of existing programs where appropriate, addition of new traditional programs and tariffs, and addition of non-traditional opportunities. Table XIII-2, below, provides further detail regarding those programs currently in development.

Table XIII-2: Demand Response Offerings in Development

Program Type	Product	Est. Date	Status
Interruptible Offerings	Interruptible Rate	2021	Interruptible Rate to be filed in fall 2020
Smart Water Heating	Electric Water Heating Control	2021	Partially launched in 2020; additional phase in 2021
Commercial Building Controls	Commercial Buildings	2021	Requires a decrease in cost of control equipment
Smart Thermostats	Home Energy Management	2023	Piloting in 2020
Saver's Switch Update	2-way communication	2023	Requires AMI installations and new equipment
Behavioral DR	"Hands-off" DR	2023	Piloting in CO, potential pilot to begin in late 2020 in MN *Technology dependent as AMI is necessary*
Electric Vehicles	Smart Charging	TBD	Program denied through CIP – exploring further opportunities
Critical Peak Pricing	Critical Peak Pricing (Opt-in)	TBD	Reviewing CO program to determine MN benefit
Other	Geo-Targeting	TBD	Pilot for Geo-Targeting to be complete in 2020 – additional development efforts to launch as a result.
Other	Reverse DR	TBD	Reverse DR to be piloted in CO as a customer rate.

By expanding the breadth of our program offerings, we hope to provide customers with the opportunity to participate in demand response offerings that meet their unique needs while expanding the ability to utilize demand response to modify load as future load profiles change. We do note, however, that some of these projects may overlap – meaning a customer may need to choose which works best for their homes or businesses, and that choice may come at the expense of participation in another program. For example, the Company may see a drop-in demand response in existing programs as new programs are offered or the load estimates for a smart thermostat may drop significantly for customers on a time-of-use rate. This overlap is important to acknowledge as we analyze incremental load.

a. Miscellaneous Tariff Request Planned for2020

The next program we hope to launch (in 2021) is an interruptible rate program that would allow increased flexibility, economic pricing and buy-through rates. We intend to file this as soon as early fall 2020 once operation details have been finalized. This program will be utilized similarly to the current Electric Rate Savings program, but it will allow for a wider range of response and control options, including buy-through offerings and seasonal control, along with increased data access for participating customers. We will offer this program as a pilot in order to test price-responsiveness and interest. Unlike PPR, this program is intended for customers with specific load availability for differing seasons (rather than months) and the ability to ramp down or shift operations during an economic event.
Our request has been delayed from our original summer 2020 timeline as we finalize cost analyses to meet the criteria outlined by our stakeholders in 2018-2019. In addition, as we finalize these details, we hope to develop one or two additional offerings (based on the options identified above in Table XIII-2) to bring forward at the same time.

b. Non-Traditional Demand Response

We also plan to pilot non-traditional opportunities and new technologies to satisfy the January 2017 Order. These additional opportunities for demand response are tied to increasing implementation of new technologies, such as EVs and advanced metering infrastructure. Smart charging and advanced metering could enable demand response opportunities, through time-of-use rates and peak time rebates. All of our EV programs and tariffs in Minnesota—including the recently-approved expansion of our Residential EV Home Service program—include time-of-use rate structures. Similarly, we are piloting new whole-home time-of-use rates in connection with advanced meters and are considering new rate design approaches that will be enabled with the capabilities of advanced meters when they are rolled out across our entire service territory.

The specific MW demand response achievements of these programs can be difficult to estimate. However, we plan to include these efforts as part of our demand response goals as technology deployment evolves.

c. Recent Challenges

We have taken, and will continue to take, significant steps to achieve 400 MW of additional demand response by 2023, and we continue to believe this is achievable. However, as noted above, the unforeseeable economic impacts of the COVID-19 pandemic may affect implementation of these plans. This crisis has not impacted all customers equally, and the full extent of its impacts remains unknown. Some business customers have lower to no demand as a result of temporary shut downs, while others have increased demand, but are unable to allow load control because they are providing essential and critical production and services. We have taken a number of actions to mitigate financial impacts to our customers, including flexing customer payment requirements, halting credit actions, and instituting a no disconnections policy. While it is too early to determine the full impact of the pandemic, we have experienced and continue to anticipate a temporary loss of demand response participation from both residential and business customers over the next several months impacting our 2020 forecast.

It is important to also note the value provided by the pandemic in our planning and customer implementation of demand response. Our Peak Partner Rewards offering has allowed customers to continue to participate differently (and, in some cases, with higher demand in particular months) during a time when load is shifting, and continued operations is uncertain. In addition,

- Our AC Rewards program and Smart Thermostat Optimization helps customers maintain lower energy bills even when working from home;
- Through virtual visits, we continue to offer thermostats to residential and small business customers (rather than onsite);
- We actively ordered equipment as part of program implementation ahead of time to prepare for the control season; and
- In a recent Petition, we requested that the Commission allow relief from tariff requirements for customers on existing rates, allowing them to remain on our demand response programs under temporary conditions, rather than be removed from the program permanently.

Despite the challenges of COVID-19, we believe we have set out the right path and are continuing to take responsible action towards achieving 400 MW of additional demand response by 2023.