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Evaluation of Energy Efficiency, Demand Response and Other Demand Side Resources in the 2024 Xcel IRP

Prepared for:

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Acronym	Definition
AI	Artificial intelligence
AMI	Advanced metering infrastructure
DERs	Distributed energy resources
DG	Distributed generation
DLC	Design Lights Consortium
DR	Demand response
DS	Distributed storage
DRMS	Demand reduction management systems
EFG	Energy Futures Group, Inc.
EFS	Efficient fuel switching
ECO	Energy Conservation and Optimization
EPRI	Electric Power Research Institute
EV	Electric vehicles
FLM	Flexible load management
GHG	Greenhouse gases
HESP	Home energy savings program
HPWH	Heat pump water heater
HVAC	Heating ventilation and cooling
IRP	Integrated resource plan
LLLC	Luminaire level lighting control
MISO	Midcontinent Independent System Operator
NLC	Network lighting control
QPL	Qualified products list

About the Authors

Energy Futures Group (EFG) is a clean energy consulting firm based in Hinesburg, Vermont with a satellite office in Canton, New York. EFG has two primary areas of practice. The first is in the design, implementation, and evaluation of programs and policies to promote investments in efficiency, renewable energy, other distributed resources, and strategic electrification. The second is in integrated resource planning and related analyses. EFG staff have worked on these issues on behalf of energy regulators, other government agencies, utilities and advocacy organizations across the United States, Canada, Europe, and China.

David Hill, a Managing Consultant with EFG is the primary author of these comments. Zack Tyler, also a Managing Consultant at EFG, contributed to the illustrative analysis of the virtual power plant.

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I. Executive Summary

The 2024 Integrated Resource Planning (IRP) modeling being conducted by Xcel Energy, Northern States Power (Xcel or the Company) provides an important opportunity to better reflect expanding potential for distributed energy resources (DERs) and the value of flexible load management as electrification increases. Advances in control and communications technologies and markets enable new levels of coordination of demand side management (DSM) resources across multiple devices and multiple sites. Developing program initiatives, rates, customer messaging, delivery mechanisms and business relationships to make optimal use of this potential will take time and can be expected to evolve over several planning cycles.

Xcel's 2024 IRP modeling and the next Energy Conservation and Optimization (ECO) plan can make critical contributions to helping Minnesota achieve policy and statutory objectives for the clean energy transition across sectors at the lowest societal costs. The Company has an admirable record of achievement with the development of demand side resources and can build upon this foundation as it looks to the next generation of opportunities for flexible load management, efficiency and distributed generation and storage. The 2024 planning cycle is an important opportunity to assess, deploy and demonstrate the value of aggregated DER and DSM for several reasons:

- Meeting emission reduction requirements.[1]
- Electricity sector emissions reductions have been on track in Minnesota but reductions from the building and transportation sectors are lagging[2] – indicating the need for accelerating progress to meet statutory policy objectives,
- Virtual Power Plants (VPP) are aggregations of DER and DSM resources but have greater potential impact than individual applications due to combination and coordination of various load shapes.
- By combining distributed energy resources with advanced communications and computing VPPs can enable lower-cost non-pipe and non-wire alternatives, while reducing emissions.
- Testing and using the emerging technologies and communication/control options can demonstrate how VPPs can minimize peak impacts from building and transportation sector electrification.

[1] 30% by 2025 and 80% by 2050. Next Generation Energy Act, Minn. Stat. § 216H.02 Greenhouse gas emissions control.
[2] Minnesota Pollution Control Agency and Department of Commerce, Greenhouse Gas Emissions Inventory 2005-2018, Biennial 2021 Report to the Minnesota Legislature, Figure 4, p.4.

- Demonstrating the capabilities and challenges of VPP development and operations at the utility level can inform and catalyze the consideration of aggregated DERs in regional transmission grid planning and operations.
- Better understanding the capabilities and limitations of VPPs is also valuable as steps are taken towards integration of gas and electric infrastructure investment and regulation.
- As decarbonization efforts move forward utilities are proposing grid improvement and gas infrastructure investments at historically high levels, highlighting the potential value and importance of strategic non-wire and non-pipe alternatives.

In this report, our comments provide a high-level overview of opportunities across four domains of demand side resources: efficiency, demand response, efficient fuel switching and distributed energy resources. In each category we highlight areas with potential for expanded investment, savings, and emission reductions.

The discussion of these opportunities is not exhaustive (we do not cover all markets, technologies, opportunities for increased demand side savings), nor is it as detailed as ECO program planning or a potential study. The thematic treatments presented here, are nevertheless illustrative of how increasing attention to demand side assets in IRP planning, in the development of next generation ECO portfolio plans, and coordinated planning, investment and regulatory oversight in the energy sector will benefit Minnesotans.

To support our review comments, and as a contribution to modeling for the current IRP, we provide an illustrative example of the composition and utility costs for a hypothetical 400 MW VPP that could be included in the resource mix for comparison to alternatives.

EFG's discussion of this illustrative VPP is not a substitute for detailed stakeholder-informed design, analysis and modeling of a VPP. Our comments should also not be seen as a detailed critique of Xcel's current ECO plan, which was approved in October 2023. Xcel has relatively strong demand side portfolios and, along with stakeholders, can continue to build on these positive accomplishments, while evolving its portfolio and planning along the thematic lines recommended in these comments. This report does not address the requirements for participation in the wholesale markets which at present (may) limit DERs ability to receive capacity credit in MISO.

II. Demand Side Domains

Energy Efficiency

As part of EFG's work to review the efficiency and demand response components in Xcel's 2024 IRP, we completed a high-level review of the Company's most recent ECO plan. These comments are not a detailed or comprehensive critique of the 2024-2026 ECO plan but focus on identifying areas with potential room for further expansion in the development and approval of future ECO plans.

The Company's continuing efforts to seek areas for enhanced cost-effective demand side savings in its ECO triennial plans impact the long-term load forecast and resource mix in its IRP analysis. In a complementary fashion, the IRP planning process can and should examine the potential for demand side resources, including those beyond the current DSM portfolio, to reduce overall system costs and revenue requirements.

Portfolio Cost Effectiveness

The Executive Summary and the cost effectiveness test results for the 2024-2026 ECO plan indicate efficiency programming is providing a valuable resource, and there is room to increase the levels of participation, spending and impacts while remaining cost effective.[3] For example, the lifetime cost of electricity saved for measures installed through the 2024-2026 portfolio is estimated to range from 1.5 to 1.6 cents per kWh.[4] The cost effectiveness test ratios are also robust, for example, the 3-year portfolio results in a benefit to cost ratio of 3.66 using the Minnesota test, and 2.66 when the societal test is applied.[5] These results indicate there is room for additional investments in demand side resources, through deeper expansion of measures already in the portfolio, or through development of new measures and initiatives promise to remain cost effective.

In the Executive Summary, Xcel notes the significant benefits of the ECO portfolio stating:

> *"In combination, the various components of this ambitious Plan will achieve energy savings well above minimum savings targets established in Minnesota statutes and generate over $1.7 billion in net benefits"*[6]

[3] 2024-2026 ECO Triennial Plan, Minnesota Electric and Natural Gas Energy Conservation and Optimization Program, Docket No. E, G002/CIP-23-92.
[4] Ibid, Table 1. p. 1.
[5] Ibid, tables 30a to 32c, p. 43 ff.
[6] Ibid, p. 1.

Further it states:

"The lifetime cost of energy savings for both gas and electricity remains well below the commodity cost of energy, demonstrating that energy savings remain our most affordable energy resource."[7]

While the proposed plans represent savings greater than 2% of annual electric sales and 1.5% of annual gas sales, we note several technology and market areas where increased portfolio savings should be examined, in both the IRP and future ECO planning processes.

The ECO plan recognizes there are certain areas where advances in technology and market adoption has reduced the ability of the program to claim incremental savings, in residential lighting for example.[8] At the same time, the plan indicates new areas of customer savings potential and niches for demand side resources, including efficient fuel switching and load shifting demand response, noting that both of these areas are currently nascent in the current triennial plan.

We recommend the following as priority areas for the Company to continue building upon the success of its demand side management initiatives to provide increased cost-effective resources for inclusion in its DSM portfolio and in long-term IRP planning.

Technology and Market Opportunities

Heat pump water heaters - For the residential market segment, demand response, and efficient fuel switching, the ECO plan includes new offerings for heat pump water heaters (HPWH), recognizing the potential based on growing customer interest, potential for Inflation Reduction Act incentives, and changes to the ECO Act. The Company notes the potential for rapid market development for substantial initial incentives to support rapid growth as customer and contractor education efforts take hold.[9]

Xcel's ECO Plan did not include a definitive anticipated total number of heat pump water heaters over the three-year period for each market segments. However, review of the forecast technical assumption tables indicated consistently small numbers for

[7] Ibid, p.2.
[8] Ibid, p. 4.
[9] ECO Plan, p. 205.

annual participation ranging from single digits up to 100 units per year.[10] In sum, looking across various market and program segments, Xcel's total heat pump water heater participation level appears to be no more than a couple hundred units by 2026. For certain market sub-segments, such as affordable new home construction, Xcel forecasts zero heat pump water heaters (both with and without communications ports).[11]

For comparison, Vermont by 2022 had more than 17,000 HPWH installed with close to 5,000 new units over the last 3 years for which data were available.[12] Efficiency Maine anticipates 14,000 heat pump water heater installations *annually* in its recent triennial plan.[13] These significantly higher levels of HPWH adoption are for states with significantly fewer residential customer electric accounts than Minnesota—Vermont has ~320,000, Maine ~750,000, compared to Xcel's 1.5 million residential electric customers Minnesota.[14, 15]

Heat pump water heaters as an emerging technology offer benefits of improved efficiency over electric resistance or combustion equipment, and water heating also has the benefit of being a load well-suited for control and load flexibility. Smart heat pump water heaters are one of the possible technologies that could contribute to a VPP portfolio.

Performance based shell measures – Improvements to building thermal shell performance through diagnostically guided air sealing and insulation are helpful to reduce energy consumption regardless of heat source, to improve comfort, health and building durability, and to reduce the sizing needs for retrofits of heating equipment. Enhanced building shell performance also provides for greater resilience in outages by better maintaining temperature over a longer duration if heating or cooling are temporarily unavailable.

The ECO plan indicates insulation and air sealing rebates have been increased based on favorable Minnesota Cost test results and to encourage participation.[16] The plan also

[10] Annual HPWH participation by market segment in the forecast technical tables include: Residential HVAC (single digits up to 60) p. 287, Home Energy Savings Program (single digits up to 54) p. 272, Efficient home construction (20 to 50, and 0 with smart controls) p. 269, and Residential Demand Response (50-100) p. 286.
[11] ECO plan, p. 267.
[12] https://eanvt.org/vermont-energy-dashboard/
[13] https://www.efficiencymaine.com/docs/TPVI_Draft_Overview_for_Public_Comment.pdf, slide 93.
[14] https://www.eia.gov/electricity/data/browser/#/topic/56?agg=0,1&geo=g048&endsec=vg&freq=M&start=200801&end=202404&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=
[15] Xcel 2023 Annual Report: https://s202.q4cdn.com/586283047/files/doc_financials/2023/ar/Xcel_Energy-AR2023.pdf
[16] ECO Triennial Plan p. 55.

directs attention and resources to training and workforce development issues to support increasing the availability of qualified air sealing and insulation contractors and to increase opportunities for workforce participation.[17]

Building shell thermal performance measures are spread across several program initiatives and include many individual measures, such as rim joist air sealing and insulation, with various levels of pre-existing R values. The ECO plan does not contain summary information on the total number of participants and counts for shell measures across the portfolio.

Reviewing the forecast technical assumption tables for the Insulation Program, the Whole Home Efficiency Program and the Home Energy Saver Program, indicates total annual air sealing and insulation participation of roughly 2,200 households. This is a significant level of participation, but given the size of the residential customer base, and robust Minnesota cost test results, there is ample room for continued expansion. Higher levels of building shell performance can be a critical strategy in Minnesota's emission reduction efforts. As more building heating loads are electrified, and cooling loads increase due to a warming climate, investing in optimal building shell performance will help to contain summer and winter peak demands on the grid and reduce the capacity and costs for heating and cooling equipment.

Cold climate heat pumps – The number of cold climate heat pumps installations forecast for the Home Energy Savings Program (HESP) which serves 1-4 unit income qualified households is extremely low with a maximum forecasted annual deployment of 16 units in 2026.[18] While likely to require significant (up to 100%) incentive support, the electrification of heating loads for income-qualified households can improve energy affordability, and efforts to support adoption of the technologies should not be limited to market-rate programs and initiatives.

Residential new construction: The ECO plan includes residential new construction for affordable and market rate housing. In support of emission reduction goals, some jurisdictions, including Connecticut, Massachusetts, and Colorado where Xcel is also active, are limiting new construction incentives to all-electric housing. Incentivizing only all-electric new construction helps to avoid the need for new gas infrastructure and customer connections and is consistent with the need to reduce consumption and emissions from fossil fuels in long-term emission reduction plans.

[17] Ibid. p. 177.
[18] Ibid. p. 272.

The ECO plan provides tiered performance-based incentives for new construction in homes that have electric service and heating fuels from the Company, starting at a level of $500 for homes 10% better than code, increasing up to $4,000 for homes 35% or better than code.[19] The Company also incentivizes home energy ratings with performance tiers for less and greater than 30% better than code, noting that less than one percent of the projects receive ratings 30% better than code.

There is room to promote deeper savings and/or to transition to making incentives only available for all electric new home construction in the portfolio. The Company can consider adding or transitioning to performance tiers based on Passive House US Zero standards to help develop and promote the most advanced approaches in new construction. Comprehensively reducing emissions from new construction projects offers long-lasting benefits, reducing infrastructure investment needs and emissions for decades to come.

Networked lighting controls – The 2024-2026 ECO plan added network lighting controls incentives to Xcel's prescriptive business new construction offerings, noting they are growing in popularity.[20] The Efficient Technology Accelerator (ETA) initiative includes luminaire level lighting controls (LLLC) as one of the five emerging technology areas with high market transformation potential.[21] Other utilities, including those in Rhode Island, Massachusetts, and Washington State have adopted midstream programs that incentivize distributors to promote networked lighting control, and to help foster adoption of lighting controls for smaller and mid-sized business customers.[22] Xcel's ECO plan includes a "mid-down" hybrid rebate structure, which provides incentives to distributor and trade allies, as well as the end use customer. As networked lighting controls, both with and without LLLC, are projected to provide high levels of deemed savings at a favorable cost per watt saved, there appears to be room for higher adoption rates in the plan. Networked lighting controls, with and without LLLC, are estimated to have 19 participants (with 2,500 units) each year in 'prescriptive new construction' but there are 0 participants for networked lighting controls in the 'business new

[19] ECO Triennial Plan, p. 74.
[20] Ibid., p. 139.
[21] Ibid., p. 236.
[22] RI Energy offers higher incentives within their midstream program if lighting fixtures include LLLC. For example, a 2x4 LED troffer is eligible for $25 alone, or $90 total if installed with LLLC. https://www.rienergy.com/media/ri-energy/pdfs/ways-to-save/rebates/ee8119-ri-commercial-lighting-incentive.pdf.
Mass Save has a similar structure in their midstream program: https://www.masssave.com/-/media/Files/PDFs/Business/rebate-forms/2024-MA-incentive-chart.pdf
Seattle City Light has a similar program in the Northwest: https://energy-solution.com/pnw-lighting-to-go/

construction' category. There is likely room to grow these programs and expand the number of new construction sites using networked lighting controls.

Building Management Systems that control networked lighting plus other building systems, such as HVAC, are eligible to be qualified as NLC systems and listed on the Design Lights Consortium's qualified product list (QPL), provided they meet all the DLC's requirements for NLC. Note that the DLC currently does not claim to qualify any HVAC-specific control capabilities of these systems.[23]

Data center efficiency – Data centers are driving load growth in many jurisdictions offering an important challenge and opportunity for efficiency, load management, and use of decarbonized electricity. Training of artificial intelligence models, advanced AI searches, and crypto-currency mining are new power-intensive end-uses driving forecasts of rapid load growth.

In a recent study, the Electric Power Research Institute (EPRI), notes that data center loads can come on-line rapidly, be highly concentrated geographically, and quickly become significant drivers of new grid infrastructure needs.[24] The report identifies three essential strategies to support the anticipated levels of expansion in data center load growth. These include a focus on data center efficiency and load flexibility, close coordination with utilities and grid planning, and better modeling tools to better understand the implications and issues associated with the rapid expansion of these large novel loads.[25] Data center efficiency opportunities include more efficient IT hardware; high efficiency equipment for cooling, lighting, and security; and more efficient AI development and deployment strategies. Efforts to increase both temporal and spatial flexibility (i.e., spreading out computing geographically) are critical to helping accommodate these new loads.

The data center efficiency program in the ECO plan continues with a mix of prescriptive and custom offerings included in the 2021-2023 triennial plan, including measures that can be implemented in both existing and new facilities.[26] Newly added to the program is a custom measure to enable load shifting opportunities to be incentivized. Even if we recognize data center activity may be concentrated on a relatively small number of larger projects, the forecast technical assumptions for computer room air conditioning equipment, which need not be restricted to data centers, in 2024 ECO plan appear

[23] https://www.designlights.org/our-work/networked-lighting-controls/technical-requirements/nlc5/
[24] Electric Power Research Institute, May 2024, "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption".
[25] EPRI, 2024, Powering Intelligence, p. 2.
[26] 2024-2026 ECO Plan, p. 122.

modest with 16, 12 and 8 total annual participants projected for the years 2024-2026.[27] As a result, there may be significant opportunity for growing participation in these programs, as well as for expanding the scope of data center efficiency measures considered and incentivized.

Demand Response

As the electrification of building and transportation loads increase to meet emission reduction goals, and new loads from data centers and artificial intelligence emerge rapidly, demand response (DR) and flexible load management (FLM) are likely to play an increasingly critical role in IRP planning and in utility demand management portfolios. This potential is further enhanced by improvements and synergies in the communications and control functions across end use devices and utility systems, which allow for a new generation of demand response initiatives and technologies to further reduce peak demand impacts of electrification and decarbonization.

The benefits and potential for increased demand response (through new technologies and market opportunities) have been recognized by the Company and by regulators in Minnesota for some time. The Company commissioned DR potential studies in 2019.[28] Recognizing the potential for enhanced DR, the Minnesota Public Utilities Commission directed the Company to acquire no less than an additional 400 MW of DR resources by 2023.[29] In its February 2024 compliance filing related to the directive to acquire additional DR resources, the Company stated:

> *"The Company believes it has begun to saturate the market with demand response efforts as described in this filing. As a result, we do not anticipate a significant amount of growth in the short term."*

It continues:

> *"However, as described in Appendix J of our 2024-2040 Upper Midwest Resource Plan (2024 IRP) (Docket No. E002/RP-24-67), demand response is quickly changing as resources become more intermittent. Additionally, technology is changing in a way that we expect will allow advanced metering infrastructure (AMI) and demand response management systems (DRMS) to*

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[27] Ibid. p. 269.
[28] See: Center for Energy and Environment, Optimal Energy, and Seventh Wave, 2019: Minnesota Energy Efficiency Potential Study: 2020-2029; Xcel 2024 IRP Appendix E: Load Management and Demand Response, and The Brattle Group; and Xcel Energy, May 2019: The Potential for Load Flexibility in Northern States Power's Service Territory.
[29] Minnesota Public Utilities Commission, December 15, 2022 Order Docket No. E002/M-20-421.

communicate with utility systems and customers in a way that significantly evolve this resource in the future. This evolution will take time to integrate, test and evolve as the Company continues to educate customers and find additional opportunities for engagement. We look forward to the new challenges this evolution will bring as demand response grows further towards "load flexibility".[30]

The 2024-2026 ECO triennial plan does not reflect enhanced load flexibility capabilities of DR; the Company largely considers its load flexibility initiatives to still be in pilot phases. However, even in more traditional DR applications, like control and/or communication with electric water heaters, there appear to be gaps in the ECO plan where higher participation levels are clearly possible.

For example, in both the affordable new home construction program and the efficient new home construction programs there are 0 electric resistance or heat pump water heaters with demand response and load shift capability anticipated.[31] The residential demand response program only forecasts 50 to 100 annual participants for heat pump water heaters with load shift and demand response capability.[32] Despite some noted barriers to start-up with smart water heaters due to supply chain issues noted in the DR compliance filing,[33] these are very low participation rates and fall well short of reflecting market potential.[34] Xcel's DR compliance filing also indicates that spending on its load flexibility pilots is running well under budget, with actual 2023 expenditures of roughly $269,000 compared to an estimated budget of more than $1.53 million.[35]

Smart vehicle charging and flexible load management for electric vehicles is another area where increased DR savings are just starting to be realized. While Xcel has vehicle charging initiatives, it has not included EV charging in the 2024-2026 ECO plan. The Demand Response Whitepaper conducted by Opinion Dynamics and included as Appendix J1 in the ECO plan indicates Xcel's EV optimization pilot has 1,337 participants, with roughly 2 MW of load impact, representing 0.2% of the total current DR portfolio.[36]

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[30] Xcel Energy, Compliance Filing Demand Response Compliance, Docket Nos. E002/M-20-421, E002/RP-19-368, E002/M-21-101& E002/CI-17-401. p. 2.
[31] ECO 2024-2026 plan, p. 267.
[32] Ibid. p. 286.
[33] Xcel Energy, Demand Response Compliance Filing, Docket Nos. E002/M-20-421, E002/RP-19-368, E002/M-21-101 & E002/CI-17-401, p. 11
[34] The demand flexibility capabilities and advantages of water heaters was reviewed by the American Council for an Energy Efficient Economy, in August 2023 Whitepaper: https://www.aceee.org/policy-brief/2023/08/demand-flexibility-water-heaters.
[35] Xcel DR Compliance filing p. 19.
[36] Xcel 2024 IRP, Appendix J1: Demand Management Portfolio Design Whitepaper, Opinion Dynamics, January 2024. p. 8.

With advanced metering infrastructure (AMI) well underway, and more than 500,000 meters installed by September of 2023, the Company is well positioned to move the FLM components of DR beyond pilot phases, and to enhance cost-effective savings from DR. As the Company's DR portfolio evolves, it will have greater ability to deploy and benefit from DR resources across both winter and summer peak periods, as well as in response to other times of grid constrained conditions and/or market opportunities.

The DR compliance filing identifies several new load flexibility and DR programs/pilots, with relatively low enrollment in the new offerings. These include programs intended to address peak days or tight system days not just designated emergencies, and include behavioral demand response, peak day partners, peak flex credit, and critical peak pricing. Peak Day Partners provides incentives for commercial and industrial customers (with a minimum of 500kW of potential load reductions) to reduce load and utilizes "bids" from the Company to establish incentive amounts for each event. The program is designed for customers unable to meet Electric Rate Savings or Peak Flex Credit eligibility obligations. The PDP pilot is designed as an opt-in, behavioral structure for customers with no penalties. With enrollments starting in October of 2023, the program reported robust growth with 82 customers enrolled by the end of the year.[37] Recognizing that these are nascent offerings, the IRP and future ECO portfolios should reflect anticipated growth in these efforts, consistent with the Company's research and market assessments.

Efficient Fuel Switching

Given the legislatively established policy goal for Minnesota to attain economy-wide net-zero emissions by 2050, and the likely economic and technical advantages of the electrification pathway in comparison to alternatives,[38] ECO plans and IRP planning should incorporate a modified focus on higher levels of efficient fuel switching (EFS) initiatives and activity.

EFS measures in Xcel's 2024-2026 ECO plan are predominantly focused on outdoor equipment, which accounts for ~70% of annual EFS incentives.[39] While opportunities for electrification of outdoor equipment can be cost effective (as illustrated by the positive participant, societal, and Minnesota Cost test results[40]), the potential need and emission reduction benefits from electrification of building loads, transportation, and commercial/industrial processes are much larger markets, with greater emissions and

[37] Xcel DR Compliance filing p. 15.
[38] Minnesota Building Decarbonization Analysis, prepared by Synapse Energy Economics, for the Clean Heat Minnesota Coalition, July 2024.
[39] See 2024-2026 EFS Executive Summary Tables, ECO plan, p. 13, 15, and 17.
[40] ECO Plan, p. 46,49,52.

emission reduction needs. These larger sectors deserve proportionally greater attention in the EFS portfolio design and in the ECO planning and IRP scenarios.

While design of the 2024-2026 EFS portfolio was subject to statutory EFS spending caps,[41] the EFS cap was removed by the legislature in 2024.[42]

As a combined gas and electric utility, the Company is in a unique position to integrate planning for gas and electric system infrastructure, and supply- and demand-side investments. Given the relatively small market and impacts for outdoor equipment in comparison other market segments, the EFS plans should include greater emphasis on technologies such as networked geothermal systems, thermal storage, and pre-electrification investments, such as improving building shell performance, electric panel optimization, and electric panel upgrades.

A recent example of how the ECO portfolio can be modified along these lines comes from the MN PUC's May 2024 decision ordering the Company to file a proposed Home Wiring Rebate Program to support Level 2 EV charging as a modification to the ECO triennial plan.[43]

Distributed Energy Resources

Broadly speaking, DERs include all the assets listed above, along with battery storage, and onsite generation. By statute, the Company can propose up to 5% of the ECO plan spending be directed to DERs, which in this context is limited to solar and battery storage.[44] The Company did not propose spending on distributed solar or battery storage in the 2024-2026 ECO plan.[45] A subsequent modification to the ECO plan added the Battery Connect pilot initiative.

By the end of 2023, the cumulative number of interconnected distributed energy resource systems statewide was 26,459, with 1.49 GW of AC nameplate capacity.[46] The

[41] Efficient Fuel-Switching (Minn. Stat. §216B.241, subd. 1c (g)), limits public utility spending on efficient fuel-switching improvements to 0.35percent per year, averaged over three years of the public utility's gross annual retail energy sales.
[42] The 2024 Energy Omnibus bill included certain modifications to the ECO Act, including removal of the EFS cap: https://www.revisor.mn.gov/laws/2024/0/Session+Law/Chapter/126/0
[43] Minnesota Public Utilities Commission, May 9, 2024: Order Approving XCEL Energy's 2023 Transportation Electrification Plan with Modifications, Docket No. E-002/M-23-452. p. 6.
[44] Distributed Energy Resources. (Minn. Stat. §216B.2411, subd. 1), Public utilities may use five percent of the total amount to be spent on energy conservation improvements under section 216.241 for distributed energy projects.
[45] ECO plan, p. 25.
[46] Minnesota Department of Commerce, 2024 Energy Policy and Conservation Quadrennial Report, July 1, 2024. Ch. 3, p. 61.

Company's Community Solar Garden program accounted for more than half of the reported installed distributed generation capacity. At the end of 2023, statewide battery storage was estimated to be more than 16 MW of utility-managed capacity, with homeowners and small business increasingly installing small battery storage units often in combination with on-site solar.[47]

The continued growth and importance of DERs is recognized in the Company's 2023 Integrated Distribution Plan, and the contained Grid Modernization Plan. The Company is preparing to launch a battery incentive program in August 2024 to support co-located solar and storage, with incentive tiers providing higher levels of support for income-qualified customers.[48] The Company is also partnering with community institutions and leveraging Federal incentives to support the development of three solar-battery microgrids as part of the Resilient Minneapolis Project, initially proposed as part of the broader grid modernization plan.[49] These are solid steps toward growing the deployment of both behind-the-meter and grid-sited distributed storage capacity, which can be leveraged in the next triennial plan into expanded efforts.

[47] Ibid. Ch.5 p. 118.
[48] Minnesota Department of Commerce: Decision In the Matter of Xcel Energy's Energy Storage Incentive Grant Program Proposal, March 20, 2024, Docket No.: E002/M-23-459.
[49] https://energynews.us/2023/10/25/xcel-energy-revives-minneapolis-resiliency-project-with-help-of-federal-grant/

III. Virtual Power Plant

The review and comments above highlight an important role for demand side resources in electric and gas utility resource planning. Xcel's demand side assets already contribute significantly to load reduction and/or the Company's capacity position through highly cost-effective portfolios, and their role as alternatives and complements to traditional supply-side investments will only increase in the coming years and decades.

Based on our review of the demand side resources in the Company's current DSM programs and IRP, we recommend the Company assess, or if necessary, be directed by the Commission to assess, an IRP scenario that by 2030 includes a VPP with at least 400 MW of additional nameplate demand reduction capacity.

Defined broadly, *"A VPP is a portfolio of actively controlled distributed energy resources (DERs). Operation of the DERs is optimized to provide benefits to the power system, consumers, and the environment"*.[50] We note that the composition of a VPP can be flexible, and the exact mix or composition of VPP assets can be open-ended (assuming it meets performance-based specifications and operational requirements) which is one of the benefits of the VPP concept.[51]

A VPP can be designed, implemented and operated by a utility or by a third-party. The VPP is typically based on the coordination and control of multiple DERs across multiple sites, and there are attendant challenges associated with recruitment, maintenance, communications and control of multiple relatively smaller assets in combination. The specific assets included in a VPP portfolio can encompass those discussed above and can include incremental expansions of existing pilot or program initiatives. Figure 1 provides a schematic overview of the elements and operations of a conceptual VPP.

[50] Brattle Group, Real Reliability, p.4.
[51] US Department of Energy, Pathways to Commercial Liftoff: Virtual Power Plants, September, 2023.

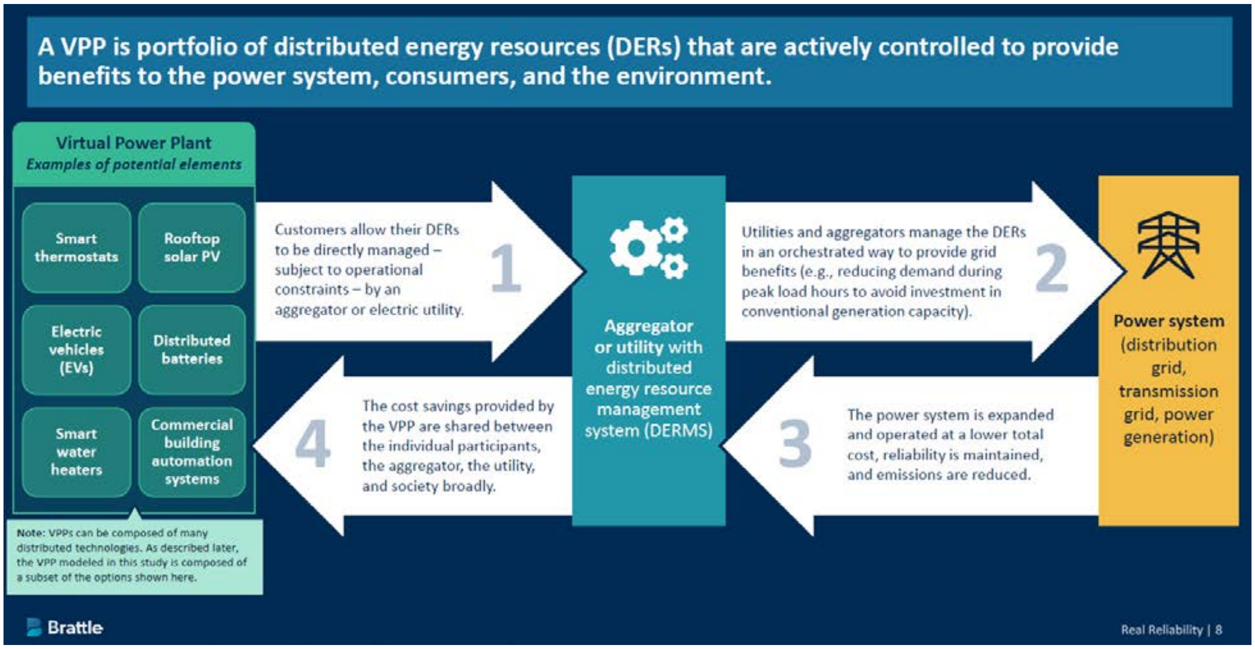

***Figure 1: Virtual Power Plant Schematic Overview*[52]**

In support of our recommendation that Xcel evaluate the opportunity for 400 MW of VPP capacity by 2030, but without prejudice toward the final constituent elements, we undertook a preliminary analysis of the potential impacts and costs for a VPP with seven contributing elements. Assumptions on participation rates and savings impact per participant draw from the research and analysis conducted by the Brattle Group for an assessment of VPP potential in California.[53] We adjusted estimates to reflect customer counts for Minnesota, with a focus on adoption and potential impacts through 2030. The seven elements we evaluated are:

- Automated Demand Response (Auto DR) using advanced building controls for commercial customers
- Behind the meter battery storage for residential customers
- Behind the meter battery storage for commercial customers
- Managed EV charging
- Grid interactive domestic hot water heating
- Smart thermostat program expansion for residential customers
- Smart thermostat program expansion for commercial customers

[52] Brattle Group, Real Reliability, slide 8.
[53] Brattle Group, 2024, California's Virtual Power Potential: How Five Consumer Technologies Could Improve the State's Energy Affordability.

Figure 2 illustrates the 2030 VPP capacity, totaling 527 MW by measure category, and Figure 3 illustrates the annual profile of capacity by measure category through 2030.

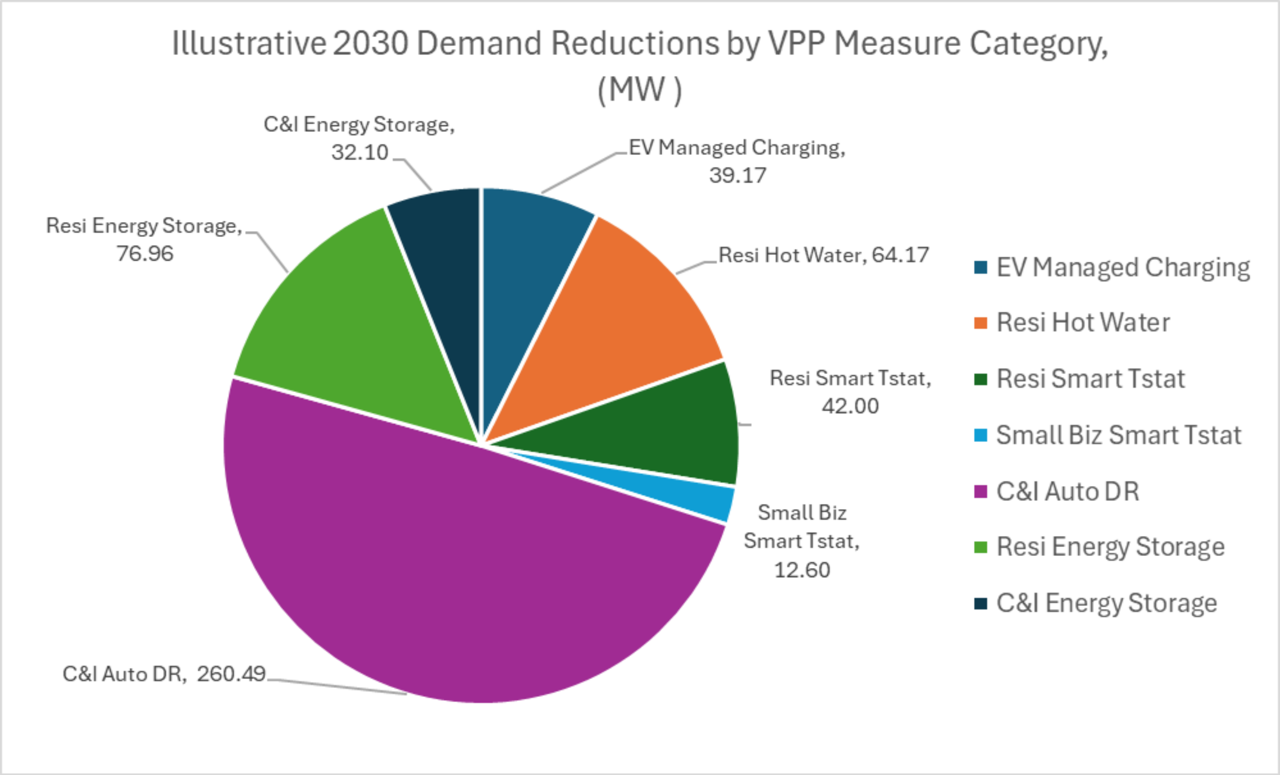

Figure 2: Illustrative 2030 VPP Capacity by Measure Type

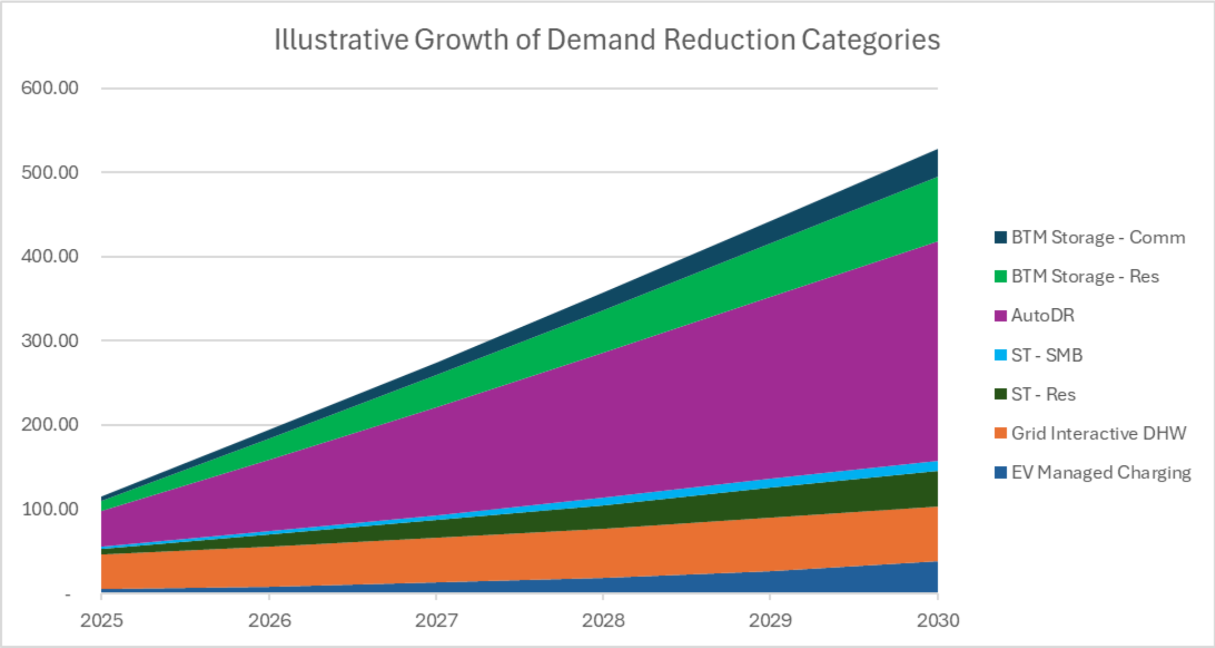

Figure 3: Illustrative Growth of VPP Demand Reduction Categories

We also provide preliminary cost estimates for the utility incentives, program start up, staffing and marketing promotional costs. The cumulative costs by measure category are presented in Table 1. We estimate roughly $231 million of cumulative utility costs through 2030, if all the VPP elements are included at the levels represented above in Figures 2 and 3.

Illustrative VPP Analysis - Cumulative Utility Cost Estimates ($2023)

Year	EV Managed Charging	Resi Hot Water	Resi Smart Tstat	Small Biz Smart Tstat	C&I Auto DR	Resi Energy Storage	C&I Energy Storage	Total
2025	$1,282,239	$ 13,013,719	$ 1,387,000	$ 484,770	$ 2,952,770	$ 6,564,428	$ 537,084	$ 26,222,010
2026	$2,549,554	$ 24,250,650	$ 3,161,000	$ 1,049,310	$ 8,532,878	$ 13,453,892	$ 1,133,807	$ 54,131,090
2027	$4,338,449	$ 37,290,449	$ 5,397,000	$ 1,768,620	$ 16,851,128	$ 20,744,393	$ 1,857,730	$ 88,247,769
2028	$6,865,712	$ 52,160,749	$ 8,095,000	$ 2,642,700	$ 27,938,703	$ 28,444,470	$ 2,714,972	$ 128,862,306
2029	$10,430,650	$ 68,888,005	$ 11,255,000	$ 3,671,550	$ 41,826,887	$ 36,555,125	$ 3,707,934	$ 176,335,150
2030	**$ 15,513,937**	**$ 87,495,764**	**$ 14,877,000**	**$ 4,855,170**	**$ 58,542,395**	**$ 45,077,182**	**$ 4,832,895**	**$ 231,194,342**

Table 1: Illustrative VPP Cumulative Utility Cost Estimates

A brief overview of our analytic approach is provided as Appendix A, and our analysis workbook detailing further inputs and assumptions is provided as Attachment 1.

IV. Conclusions

Minnesota has been a leader and continues to benefit from inclusion of demand side resources in system planning and utility portfolio of services. Trends in electrification and distributed resource and virtual power plant technologies and business models increase the opportunity for demand side resources to contribute as planning activities cut across gas and electric services and the State makes progress towards economy-wide emission reduction goals.

Xcel's IRP contains several types of demand side resources, and the Company historically has had a significant demand management portfolio. However, there is still room for improvement by incorporating higher levels and more dynamic combinations of DERs both individually and or as components of a VPP. Given the potentially large capacity additions the Company is proposing in this resource plan (e.g., more than 2200 MW of new gas plants by 2030), greater attention to modeling DERs and DSM may provide cost-effective and lower-emission alternatives.

Appendix A: Description of Approach and Elements in the VPP Analysis

The VPP analysis included in these recommendations draws heavily on a recent study conducted by the Brattle Group for California. This study showed that VPPs have the potential to reduce 2035 system peak demand in California by more than 15% using technologies and programs that are commercially available and cost-effective in the market today.[54]

We conducted an analysis using the Brattle report and our review of the Company's ECO and IRP plans to assess the level of additional DER resources available in Xcel's Minnesota service territory primarily using the measures and programs included in the VPP report for California. Specifically, we referenced the assumptions around measures included in the VPP, savings per participant, the frequency and duration of DR events, and anticipated program costs to create an illustrative example of a VPP in Minnesota.

The distributed resources and measure categories from the Brattle study included in the analysis include smart thermostats, grid interactive water heating, automated DR (auto DR) for medium and large commercial and industrial (C&I) customers, and managed EV charging. Auto DR, as defined in the Brattle report, is a program where the "energy management system of large buildings and facilities is controlled to automate and optimize electricity demand reductions in connected end-uses such as light and HVAC."[55] In addition to these measure categories, the EFG analysis includes behind-the-meter storage for residential and commercial customers.

The EFG analysis shows that the inclusion of VPPs as a DR mechanism could help the Company achieve additional demand savings of 527 MW by 2030, based on participation rates ramping up starting in 2025. We estimate cumulative utility costs (including start up, staffing, incentives and marketing) for this level of VPP capacity to be roughly $231 million. These calculations are not intended to be precise as many assumptions were used to calculate these values; rather, these calculations are intended to show the potential for a VPP in the Company's service territory and highlight the need for the Company to conduct their own investigation, using relevant customer and DR program data, on the potential for cost-effective VPP application in their IRP model.

[54] Brattle Group, 2024, California's Virtual Power Potential: How Five Consumer Technologies Could Improve the State's Energy Affordability.
[55] Ibid.

The assumptions in the Brattle report were adjusted to reflect Minnesota specific customer counts and the analysis was also adjusted to reflect information on the current levels of activity for individual VPP elements to avoid double counting. For example, for EV charging, we applied the anticipated participation rate to be incremental and above those estimated in the current IRP analysis. While the analysis extends through 2050, we recommend a focus on the results through 2030 as illustrative of the value and importance of including a VPP in the IRP modeling for the near-term planning horizon and investment decisions.

Our analysis is illustrative and by design has limitations. We do not intend to provide a specific or maximum quantity of VPP DR the Company can achieve. Rather, we wanted to rapidly assess whether a VPP can be designed to provide more capacity savings than are currently modeled in the IRP. Our analysis supports the conclusion that the Company should consider a VPP as an approach to obtaining more ambitious levels of DR than currently evaluated.

Attachment 1: VPP Analysis Workbook

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