STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph Sullivan	Commissioner
John Tuma	Commissioner

In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan	)))))	**PUC Docket No. E002/RP-19-368**

JOINT COMMENTS OF VOTE SOLAR, INSTITUTE FOR LOCAL SELF RELIANCE, THE ENVIRONMENTAL LAW & POLICY CENTER, AND COOPERATIVE ENERGY FUTURES

I. Introduction and Summary

Vote Solar ("VS"), the Institute for Local Self Reliance ("ILSR"), Cooperative Energy Futures ("CEF") and the Environmental Law and Policy Center ("ELPC"), collectively the Distributed Solar Parties ("DSP") are pleased to provide these comments on Xcel Energy's ("Xcel" or the "Company") 2020–2034 Upper Midwest Resource Plan.

A. Distributed Solar Parties

Cooperative Energy Futures is a member-owned clean energy cooperative that works to empower communities across Minnesota to build energy democracy through solutions that are clean, local, and ours. CEF has over 900 member-owners across Xcel's Minnesota service territory currently participating in community solar, on-site solar, and energy efficiency solutions. CEF has a particular focus on empowering low-income households, communities of color, and renters to participate in clean energy solutions that work for everyone. CEF empowers its members to create an energy future that protects community health and affordability and builds community wealth.

The Environmental Law & Policy Center is a not-for-profit public interest environmental organization that works to achieve cleaner air, advance clean renewable energy and energy efficiency resources, improve environmental quality, protect clean water, and preserve natural resources in Minnesota and throughout the Midwest. ELPC's members, several of whom live and work in Minnesota and in Xcel Energy's service territory, have an interest in the decarbonization of the electric power system, including through the deployment of clean energy resources at both the utility and distributed-scale.

The Institute for Local Self-Reliance has a vision of thriving, diverse, equitable communities. ILSR is a national research and advocacy organization that partners with allies across the country to build an American economy driven by local priorities and accountable to people and the planet.

Vote Solar is an independent 501(c)3 nonprofit working to repower the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. VS seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. VS has over 90,000 members nationally, including over 2,500 members in Minnesota. VS is not a trade organization, nor does it have corporate members.

B. Summary of Comments

The DSP concur with findings and recommendations of other parties and, while we touch briefly on those findings and recommendations here, the focus of these comments will be the Integrated Resource Plan's ("IRP") treatment of customer-sited resources, including distributed solar.

A fundamental problem with utilizing system resource planning models with distributed resources is that models use costs *to the utility* as a model input, whereas the cost of distributed resources are borne primarily by the host customer while providing system benefits to the utility. With current models, optimizing a resource plan to include distributed resources requires identifying the benefits to the system but separating the cost to the utility from costs to the customers who own the generation and using only the utility costs as a model input.

We developed a method to offer increased distributed solar as a system resource to the capacity expansion model by determining several increments of distributed generation additions that can be realized by the utility through recognized price response factors. This allows the Commission to determine the optimal level of customer owned distributed generation for the system through traditional system expansion modeling based on the cost to the utility to produce each increment of additional distributed generation. We refer to this going forward in these comments as the Distributed Generation Resource ("DG Resource" or "DGR").

We worked closely with the Sierra Club to incorporate our DGR model into their alternative modeling to understand how distributed generation could contribute to the most cost-effective plan. We support the Clean Energy for All ("CEFA") plan that is also recommended by the Sierra Club's comments. The CEFA plan would result in a total of 1,851 MW of rooftop distributed generation, 2,051 MW of community solar gardens ("CSG"), and 5,735 MW of utility scale solar by 2034. CEFA would (1) save customers $2.2 billion in societal cost between now and 2034 in current dollars (present value of societal cost) while also building significantly more clean energy, optimizing distributed generation, and, importantly, reducing reliance on centralized fossil fuel generation. In conclusion, our preferred plan is to adopt the CEFA plan proposed by the Sierra Club.

The Supplement Preferred Plan proposed in the Company's June 30, 2020 Supplemental Plan filing[1] underestimates the potential resource opportunity of distributed generation by modeling distributed generation through a convoluted method that fails to accurately identify the cost to the utility and does not allow the model to select the optimal level of distributed generation. The Company starts with a net corporate sales projection that accounts for load reductions through energy efficiency, demand response, and distributed generation. It then adds those loads *back into its base load forecast* and allows its expansion model to select *only some types* of resources: efficiency and demand response, but not distributed generation. Rather than optimizing a plan for its system by including distributed solar, the Company's model plans around distributed solar

[1] Supplement, 2020–2034 Upper Midwest Integrated Resource Plan, at 2, Docket No. E002/RP-19-368 (Minn. PUC June 30, 2020) ("Preferred Plan," "Supplement Plan," or "Supplement Preferred Plan").

resources by forcing them into the model at fairly low levels that reflect a historic monopoly utility bias against customer and third party owned generation. The Company's result is an unsurprising portfolio of predominantly centralized, utility-driven and utility scale resources. This contrasts with the optimal plan provided by CEFA that is more customer-driven, decentralized, and cost-effective.

The second part of these comments identifies the benefits and technical potential of distributed generation. Specifically, distributed generation uniquely leverages customer capital rather than utility capital, provides benefits back to customers to a greater degree, and provides the potential for equity and access benefits for communities that have been left behind in the clean energy transition. An analysis of the Company's service territory confirms that the system will allow for high levels of distributed generation potential. In fact, the Company's system will benefit from greater distributed resources that can reduce total system cost through co-optimization of distribution, transmission, and resource planning.

While the DSP supports many of the elements of Xcel's Preferred Plan, there are other elements that are more concerning and should be reconsidered. As will be discussed in the results of the modeling and our proposed alternative plan, the proposed 835 MW Sherco Combined Cycle plant is not needed and can be reliably replaced with the proposed clean energy portfolio (composed of distributed energy resources ("DER"), solar, wind, and storage). In addition, we note that relicensing of Monticello is not the lowest present value of societal cost solution in our modeling.

II. IRP Requirements

A. Statutory and Rule Requirements

Xcel is required to file a resource plan setting forth "a set of resource options that [Xcel] could use to meet the service needs of its customers over a forecast period, including an explanation of the supply and demand circumstances under which, and the extent to which, each resource option would be used to meet those service needs… includ[ing] using, refurbishing, and constructing utility plant and equipment, buying power generated by other entities, controlling customer loads, and implementing customer energy efficiency." Minn. Stat. § 216B.2422, subd. 1(d), 2. The State of Minnesota Public Utilities Commission (the "Commission" or "PUC") must then approve, reject, or modify the plan based on a set of criteria adopted through PUC rules and applied "consistent with the public interest." *Id.* Pursuant to the PUC's rules, it evaluates a resource plan's ability to:

A. maintain or improve the adequacy and reliability of utility service;

B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;

C. minimize adverse socioeconomic effects and adverse effects upon the environment;

D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and

E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

Minn. R. 7843.0500, subp. 3.

Distributed generation must be considered as part of the Company's resource plan pursuant to several provisions of statute and regulation. First, distributed generation offsets customer loads and decreases the electricity demands that must be included in the resource plan. Minn. Stat. § 216B.2422, subd. 2(a). Second, the definition of a resource plan includes "controlling customer loads, and implementing customer energy conservation." *Id.*, subd. 1(d). Distributed resources both control customer loads and constitute customer conservation. Third, the PUC cannot approve a non-renewable facility if there are renewable resources available and in the public interest, based on greenhouse gas reduction goals, impacts on grid reliability, utility and ratepayer impacts due to intermittent nature of generation, and utility and ratepayer impacts from reduced fuel price risk, transmission costs, resource diversity, and environmental compliance costs. *Id.*, subd. 4.

The PUC is not limited to Xcel's plans. Other parties can present "proposed resource plans different from the plan proposed by the utility" by including "a narrative and quantitative discussion of why the proposed changes would be in the public interest, considering the factors listed in part 7843.0500, subpart 3." Minn. R. 7843.0300, subp. 11. In these comments, we offer a resource plan that is different from Xcel's proposal and would serve the public interest. The Company's plan includes fossil resources that are avoided in the CEFA plan, which adds more renewable resources and reflect an improvement on grid reliability, customer impacts, price risk, diversity and environmental costs.

III. Summary of Xcel's Supplement Preferred Plan

Xcel presents "Scenario 9-Early Coal; Extend Monticello" as its preferred portfolio. According to Xcel, that plan involves retiring all coal generation by 2030 and reducing operations at some units prior to retirement, adding 6,000 MW of new renewables, adding demand-side management by 400 MW by 2023, and average efficiency savings of over 780 gigawatt hours, and adding firm peaking resources as needed in later years. Cover Letter of Supplement, 2020–2034 Upper Midwest Integrated Resource Plan, at 2, Docket No. E002/RP-19-368 (Minn. PUC June 30, 2020); Supplement Plan at 28. Xcel also proposes to proceed with the legislatively approved construction of the proposed 835 MW Sherco Combined Cycle natural gas plant to begin operation in 2027. In addition, Xcel proposes to seek a ten-year license extension for the Monticello nuclear power plant, which currently expires in 2030. Alternatives to these two resources will be discussed in our discussion of the modeling results for the CEFA plan.

A. Treatment of Distributed Resources in Xcel's Modeling Approach

Xcel's original Plan filed in 2019 started to model distributed solar in the conventional way - by subtracting forecasted CSG and rooftop distributed generation from gross load forecasts to arrive at a net load forecast which was used as the input to the modeling software. However, in the Supplemental Plan filed in June 2020, Xcel modified its approach and modeled the distributed generation (both rooftop and community solar) as a supply resource.

The Company summarized its treatment of distributed generation resources as follows:

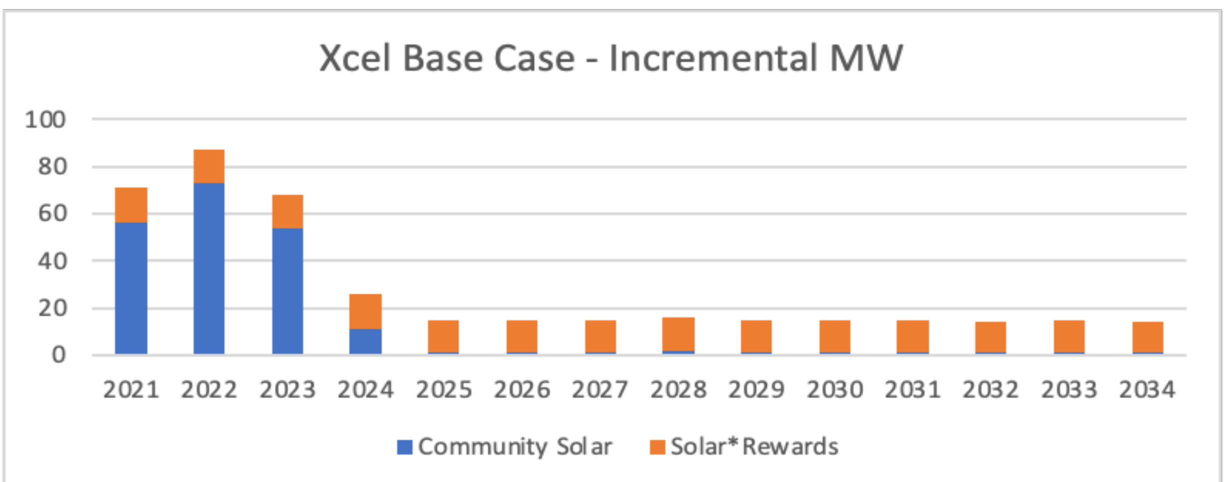
> We used these corporate forecasts as the basis for our Strategist and EnCompass modeling but made some further adjustments, in order to account for modeling load modifying resources – such as EE, demand response (DR), and distributed generation – as competing with supply-side resources in our modeling process. Prior to our 2020-2034 Resource Plan, we netted out these resources at an assumed fixed 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 our initial plan we filed in July 2019, for the first time 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 our resource planning process in order to allow these resources to compete with traditional supply-side resources, such as large-scale renewables or gas resources.

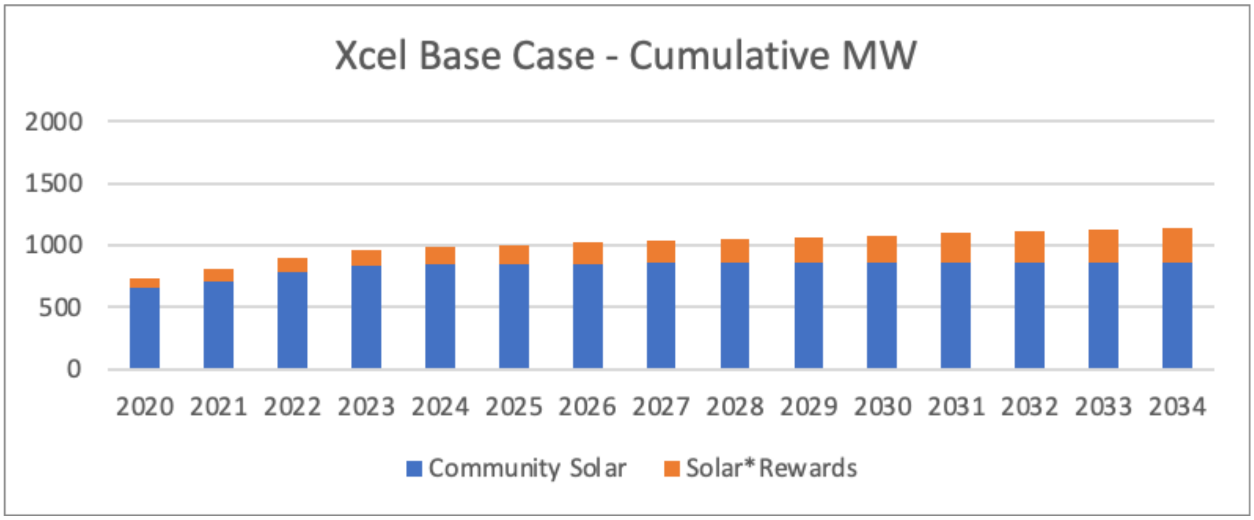
Supplement Plan at 19.

That is, Xcel added back the reduced load represented by distributed solar, energy efficiency and demand response and then allowed the model to select *only* efficiency and demand response, but not distributed solar. To account for distributed solar, Xcel's model forces in one of two levels of distributed solar growth: Base Case and High Distributed Generation Adoption Sensitivity ("HDS").

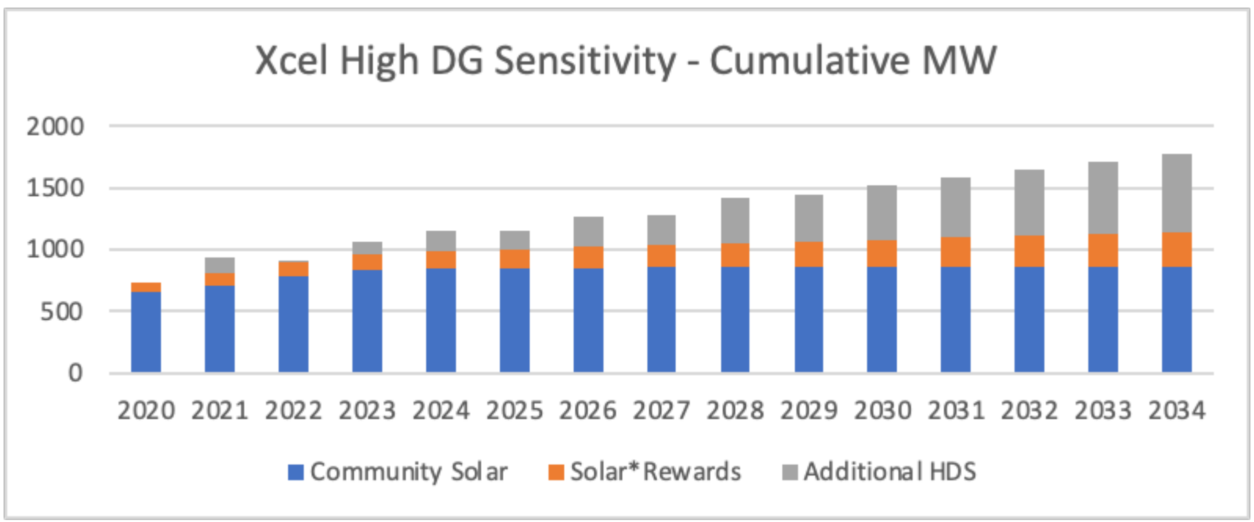
The Base Case forecast purportedly reflects distributed generation adoption levels based on the end to Solar*Rewards funding after 2021 (with final installations by 2023), the end of Made in Minnesota awards after 2017, and an adjustment based on historic values for lag times to completion and attrition. Supplement Plan, Attach. A at 37. The resulting forecast is an assumed cumulative 738 MW of distributed solar through 2020, then cliff between 2021–2023 corresponding to the end of Solar*Rewards incentives, followed by a very low 15 MW per year rate after 2023. *Id.* The two charts below show the base case incremental and cumulative distributed generation and community solar gardens in Xcel's Supplement Preferred Plan.



Cumulatively, it results in 1,139 MW of Community Solar and Solar*Rewards by 2034.



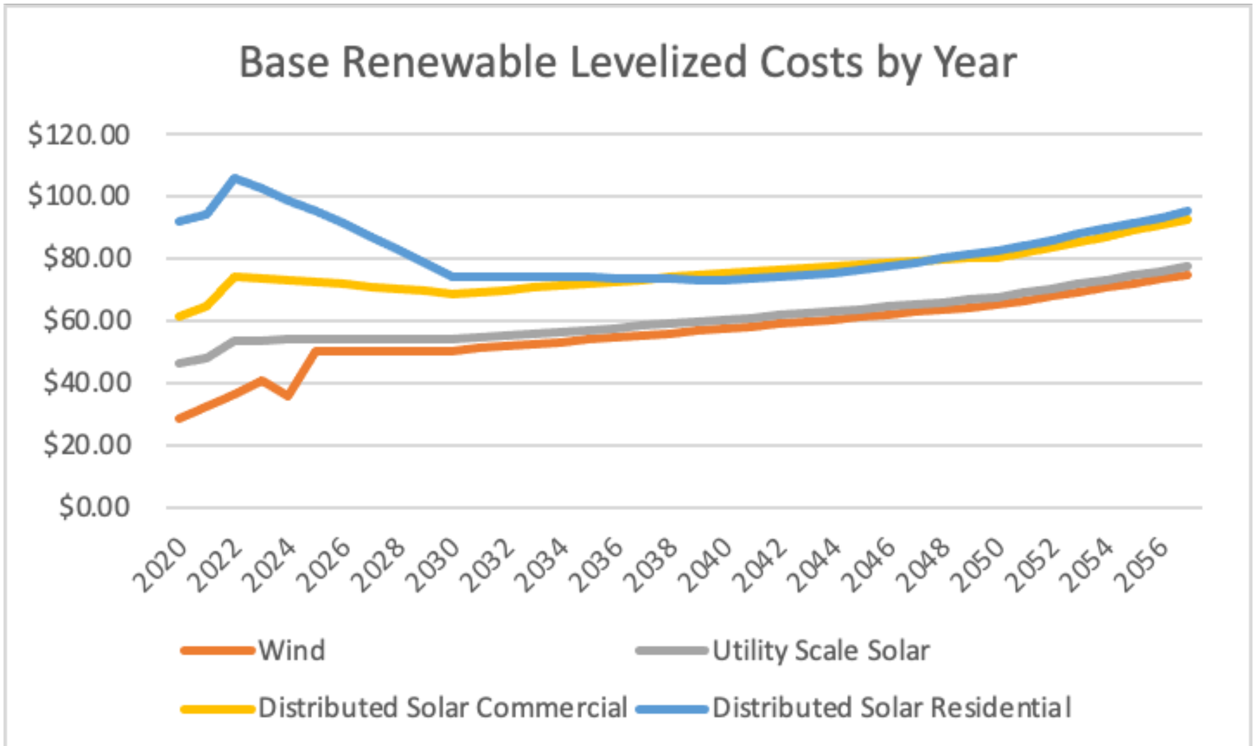
HDS purportedly assumes the same 2021 cliff on Solar*Rewards and 2017 end to Made in Minnesota incentives, but assumes a higher growth of organic distributed solar (i.e., even without incentives) based on "a Payback adoption model that assumes a 10 percent reduction to the solar installation cost curve, relative to the base case, starting in 2020." *Id.* at 38. That is, the Company assumes a 10% cost reduction, which it believes will produce an additional 639 MW of distributed solar by 2034. *Id.* at 38–39; *see also* Supplement Plan at 38.



We also note that Xcel's HDS analysis assumes a reduction in the residential investment tax credit to 22% through 2021 and then expiring. Supplement Plan, Attach. A at 37. Congress amended the Internal Revenue Code § 48 as part of the Consolidated Appropriations Act, 2021 (i.e., the Covid stimulus passed on December 21, 2020) after Xcel's filing. The residential credit is now 26% through 2022, and 22% credit through 2023. The resulting cost savings and increase in the number of distributed generation installations were not accounted for in Xcel's forecasts.

Additionally, Xcel's HDS sensitivity was always paired with assumptions of lower fuel price, lower load, and lower technology costs for other resources. Supplement Plan at 35. Xcel did not test the HDS solar adoption levels with base case or higher levels of fuel price, load, or costs for other resources. Thus, the Company's filings fail to analyze the impacts of the HDS scenario under the baseline loads and costs or other variables.

Xcel's Supplement Plan also incorrectly treats the cost of customer-owned generation as fully a utility cost. First, the narrative suggests that it utilized a levelized cost of energy ("LCOE") of $46.12/megawatt-hour ("MWh") for utility-scale solar, $61.16/MWh for distributed commercial solar, and $92.16/MWh for distributed residential solar in its modeling as reflected in the following figure:



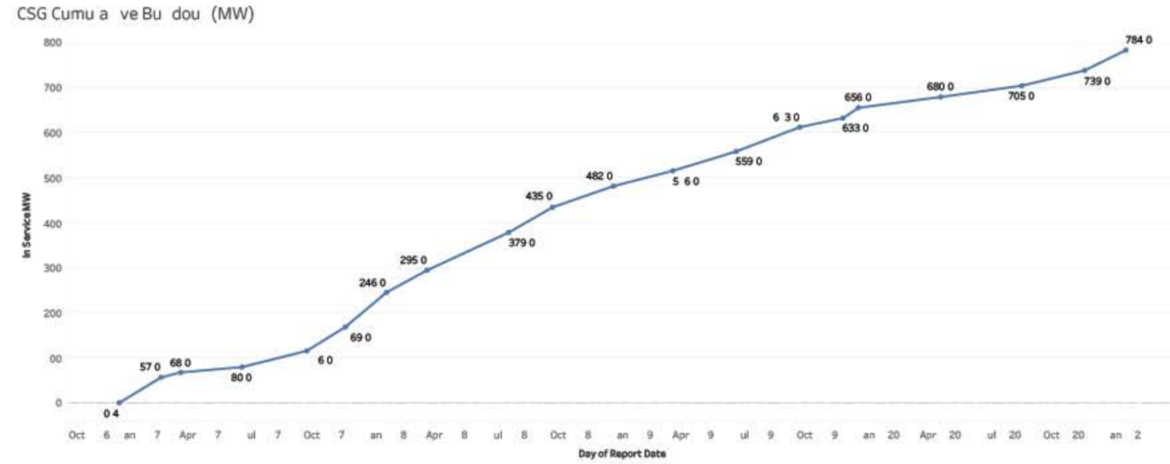
This suggests that customer-owned distributed generation costs are borne fully by the utility and are never lower cost than utility scale solar. However, the costs modeled in EnCompass are different. These differences are discussed in more detail in the TRADE SECRET comments submitted separately. Supplement, 2020–2034 Upper Midwest Integrated Resource Plan, Attach. A: Supplement Details, Section IV Modeling Assumptions and Inputs, at 72 (Table IV-18), Docket No. E002/RP-19-368 (Minn. PUC June 30, 2020) (TRADE SECRET VERSION).

B. Community Solar

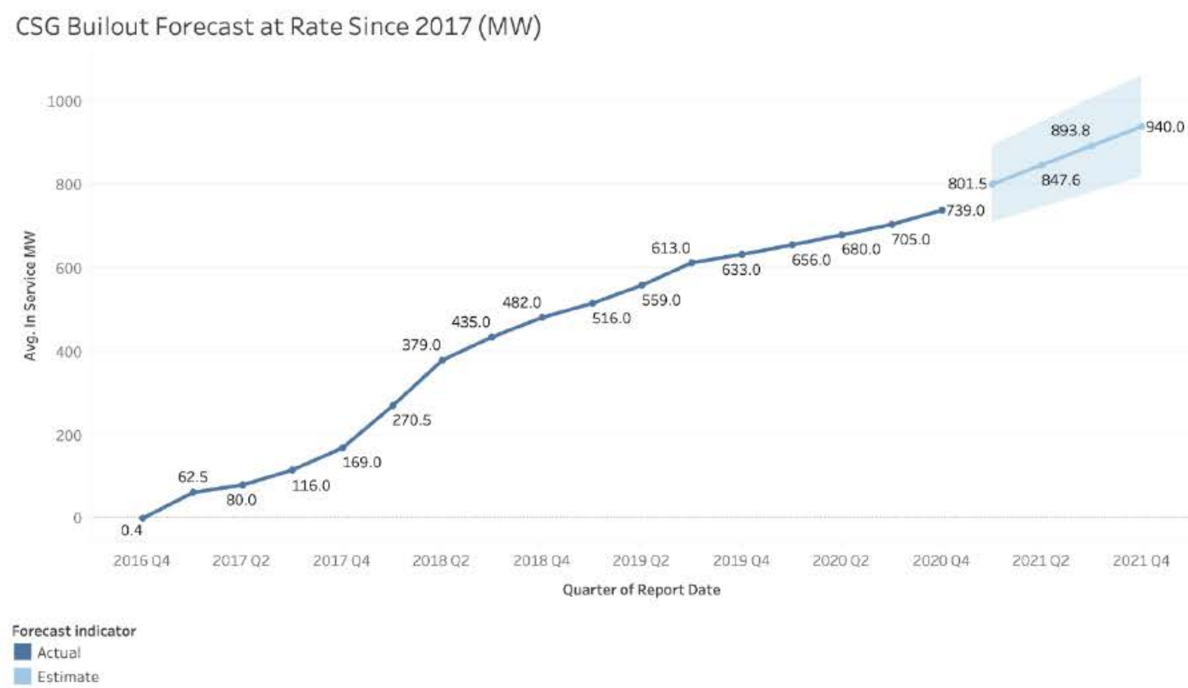
The CSG program was created by the Minnesota Legislature in 2013. Minn. Stat. § 216B.1641. Under the program, Xcel is required to purchase the output from CSGs located within the utility's service territory at the value of solar rate or retail rate. *Id.*, (c), (d). Customers of the utility can pay a subscription fee for a portion of the output of the solar garden and receive a credit on their monthly bill reflecting the solar garden's output for that month. *Id.*

In the statute, the program is uncapped, meaning that the only practical constraint on the program is the capacity of the distribution grid to accommodate systems administrative constraints established in statute, such as requirements that subscribers to a garden be located in the same county or a contiguous county as the CSG.

Since CSG's first started coming online in late 2016, the program has grown steadily and robustly. In the most recent Quarterly Compliance Filing filed on January 26, 2021, Xcel reported 382 sites in service with a capacity of 784 MW AC.



The program remains popular. According to the January 21, 2021 Quarterly Compliance Filing, there were 420 new applications for CSG filed in 2020. The current queue includes applications for 518 sites representing 483 MW of capacity. As shown in the chart below, simply extrapolating growth at the same rate results in 940 MW of CSG capacity by the end of 2021. Thus, it is entirely possible that the actual amount of CSG at the end of 2021 will exceed Xcel's 2034 forecast (863 MW).



Xcel's modeling includes a CSG forecast that essentially builds out the level of CSG in the application pipeline at the time the modeling was conducted and is completed by 2023. The forecast then includes very little additional community solar after 2024 (*see supra* Section III).

Xcel's Supplement Plan also assigns a cost to CSG generation. Notably, the purchase price of CSG generation to the utility reflects more than the production capacity and energy value of the solar produced. At either the applicable retail rate or value of solar rate, the cost of the output also reflects avoided distribution system costs, line losses, and environmental costs. *See e.g.*, Minn. Stat. § 216B.164, subd. 10(f).

Those costs are not included in Xcel's expansion plan modeling for other resources, so the fully loaded CSG credit is not comparable to model inputs for other resources in Xcel's planning model. Specific discussion about the modeling of CSG costs in the EnCompass modeling are discussed in the TRADE SECRET comments.

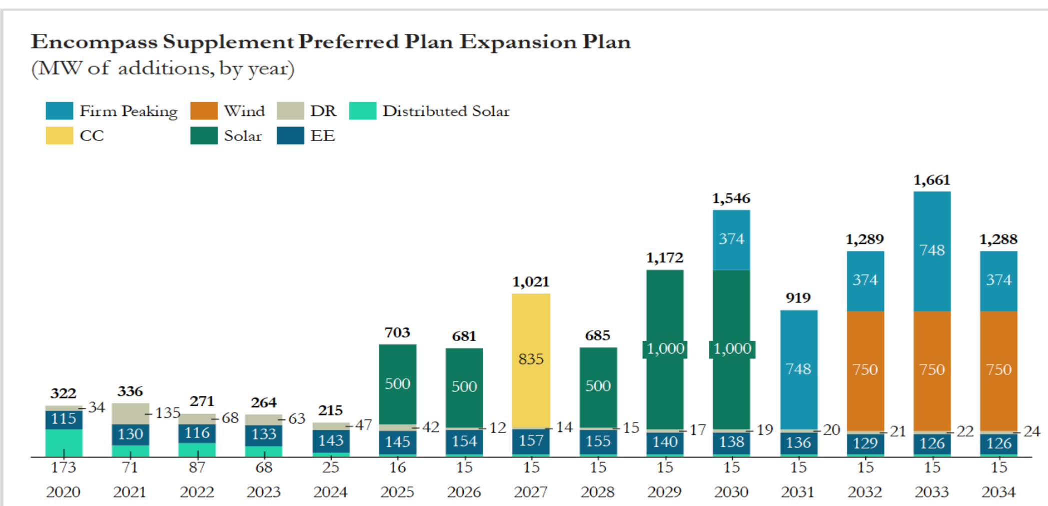
C. Modeling Results and Plan Selection

The Company's Supplement Plan evaluates candidate portfolios along four main dimensions:

- Cost
- Environmental
- Risk
- Reliability

The key elements of the Cost dimension are 1) the Present Value of Societal Costs ("PVSC") and 2) transmission expansion costs.[2] PVSC adds carbon costs to the present value of revenue requirements ("PVRR") as generated by the expansion model. Although PVRR is presented in the Company's results, it uses PVSC as the key metric to evaluate costs.

The Company's selected alternative is Scenario 9 which includes the following resource additions as reflected in Figure 3.2: Supplement Preferred Plan Resource Additions of the Supplemental Plan. Supplement Plan at 62.



The main features of Xcel's Supplement Preferred Plan are 835 MW of new fossil gas fired generation in 2027 and 3,500 MW of solar and 2,500 of wind between 2020 and 2034. Within

[2] Table 2-5: Scenario Modeling Portfolio Scorecard in the Supplement Preferred Plan explains each of these elements in more detail and it is not necessary to detail it further here. Supplement Plan at 41.

the Five-Year Action Plan (which considered the near-term portion of the plan on which the Company intends to request approval), the Supplement Plan does not add utility scale solar. However, the Company notes in the Supplement Preferred Plan that it nevertheless requests approval to build 400 MW at the Sherco substation in its June 17 Report in Docket No. E,G999/CI-20-492. Covid-19 Relief and Recovery Report, Docket No. E,G999/CI-20-492 (Minn. PUC June 17, 2020). The Company notes that if approved, that project would largely fulfill its Preferred Plan's addition of 500 MW in 2025.

The Company's preferred plan also includes 2,600 MW of "firm peaking" resources from 2030–2034. Although the Company does not identify what these resources will be, they note that in the original plan, they were modeled as natural gas combustion turbines ("NGCT").

> These proposed additions are needed to continue to support grid reliability and resiliency in light of the increased renewables being added to the system and the baseload units being retired. As discussed in our initial filing, although we modeled these units as CTs, we are not committing to a specific resource type to meet this need because these units are not needed until the out-years of our current Plan.[3]

Thus, while adding a significant amount of utility scale and rate based renewable generation, the Supplement Plan also includes a substantial investment in additional fossil generation that will lock in carbon emissions and cost recovery long past 2050.

The Supplement Plan also presents distributed solar as a capacity addition, unlike the original 2019 filing. However, as discussed in these comments, the model is not actually allowed to pick the resource and distributed solar is not utilized as part of an optimized resource mix. Instead, distributed solar is forced into the model according to forecasts as discussed above.

IV. Conventional Distributed Generation Modeling, Xcel's Approach, and Critique

The conventional utility planning approach for DERs (to the extent they account for DERs at all) is to treat them as an exogenous variable to their capacity expansion modeling. Like weather, or the economy, DER growth is something that "happens to" the utility and needs to be planned around, rather than something that the utility can affect and can utilize to meet its customers' requirements.

The conventional approach typically forecasts energy efficiency and distributed solar adoption and then subtracts them from the utility's gross load forecast to establish a net load forecast. The net load forecast is then used, either as the base case or a sensitivity, to model system expansion through large, production-side, additions.

A. Xcel's Distributed Generation Modeling: DER Adoption Modeling Techniques

Forecasting the adoption of technologies impacting utility loads is a well-known problem. There are a number of interacting variables at play, including:

- technology prices (i.e. the cost of installing a PV system);

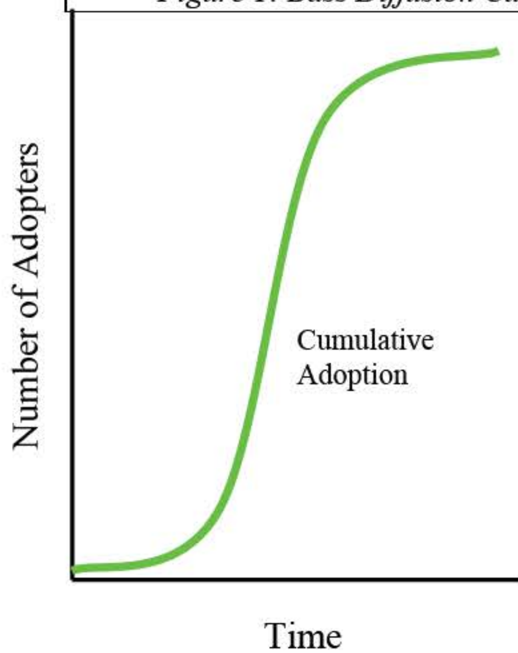
[3] Supplement Plan at 64.

- customer preferences for adopting technology;
- customer preferences for attributes other than price (e.g., environmental benefits of distributed generation and self-sufficiency);
- clustering and neighborhood effects;
- price and rate structure of electric service;
- net metering or excess distributed generation compensation structure; and
- state and federal policies, incentives and credits.

Distributed generation adoption rates can be forecast through a variety of available methods.

- Diffusion models (including Bass diffusion and threshold diffusion)
- Customer behavior (discrete choice experiments, conjoint analysis)
- Machine learning / fuzzy logic (Neural networks, decision trees)
- Agent-based models
- Macroeconomic / econometric
- Combined market penetration (combinations of above methods)

Figure 1: Bass Diffusion Curve



The most widely used model is a Bass diffusion model (*see* Figure 1). The Bass diffusion model applies the observed "S-curve" of technology adoption across many types of technologies. Notably, Xcel uses the Bass diffusion model and econometric modeling to forecast electric vehicle adoption in the Supplement Plan.[4]

An alternative method is to utilize an agent-based decision making model. The National Renewable Energy Laboratory ("NREL") recently released a new version of its dGen model that predicts individual decision-making by consumers in a population. Agent-based models are strong explanatory models, but requires a higher level of granularity of customer data and can be computationally intense. We utilized a model adapted from the NREL dGen model as one of two models to predict future distributed solar adoption in Xcel's service territory.

We also developed a second model based on the one proposed by Eric Williams, Rexon Carvalho, Eric Hittinger, and Matthew Ronnenberg in the journal *Renewable Energy* in December 2019.[5] The model relies on a robust relationship between the net present value

[4] Supplemental Plan at 42.

[5] Eric Williams et al., *Empirical development of parsimonious model for international diffusion of residential solar*, 150 Renewable Energy 570, 570–577 (2020) ("Williams et al." or the "Williams model").

("NPV") cost per kilowatt for a customer to install solar and the likelihood of adoption. This model specification and derivation is detail below in Section VII: DG as a Resource Model.

B. Xcel's Distributed Generation Modeling: Rooftop Distributed Generation Costs

As described above, Xcel added projected distributed solar growth back into load forecasts and then forced its model to accept DER as a supply side resource at specified levels with static price assumption. That overstates the "cost" of distributed solar by incorrectly implying that the utility incurs the full cost of distributed solar which is actually borne by the customer who purchases the distributed generation system. The "cost" to the utility consists only of the incentives, if any, provided by the utility to the distributed generation owner. In fact, one of the largest benefits to the system from distributed generation is that private investment, rather than the utility and ratepayers, pay the capital costs of the generation.

C. Xcel's Distributed Generation Modeling is Passive

Xcel's treatment of distributed solar in its HDS sensitivity also forces the model to optimize around distributed solar, rather than allowing the model to optimize the future system with customer-sited solar as a resource. Xcel partially acknowledges that its treatment of distributed solar does not reflect distributed solar's ability to be part of an optimized resource mix. According to Xcel's Supplement Plan filing:

> [I]t is important to note that these Futures Scenarios are intended to examine the resiliency of each baseload scenario under a combination of assumptions changes that we believe are plausible future states. <u>They are not intended to show us which future is overall least cost for our system</u>; we do not have full control over the level of distributed solar or electrification growth on our system, and we have no control over variables such as fuel prices and new resource capital costs. Supplement Plan at 35 (emphasis added).

In response to discovery, the Company further elaborates that:

> In other words, the High Distributed Solar Future Sensitivity is not intended to represent of *(sic)* a specific future Plan. Instead, the sensitivity helps us assess how any given baseload scenario's optimal portfolio and associated costs could change under a potential future in which technology costs are lower than our base assumptions, and higher levels of distributed solar resources are adopted in our service area. Xcel Resp. to VS-ILSR-CEF IR#-3, at 2, Docket No. E002/RP-19-368 (Minn. PUC Aug. 21, 2020).

Thus, the Company's analyses of both the baseline and high distributed future levels of distributed solar continue to assume that impacts of distributed resources are passive and cannot be produced and incorporated into an optimized resource mix. As discussed below, it is possible for the Company to adopt policies and incentives that would lead to an optimal level of distributed solar adoption for the system.

D. Xcel's Distributed Generation Modeling: Community Solar Capacity and Costs

Xcel's Supplement Plan projects very low future CSG expansion. The Company forecasts CSG additions at historic rates for a few years and then virtually no additional community solar for the rest of the planning horizon. Like customer-sited distributed generation discussed above, CSG resources are forced into the model at specified costs. As discussed in the Trade Secret supplement to these comments, Xcel's presumed costs for community solar appear to be vastly overstated.

V. Policy and Technical Justification for A Future with High Penetration Distributed Generation

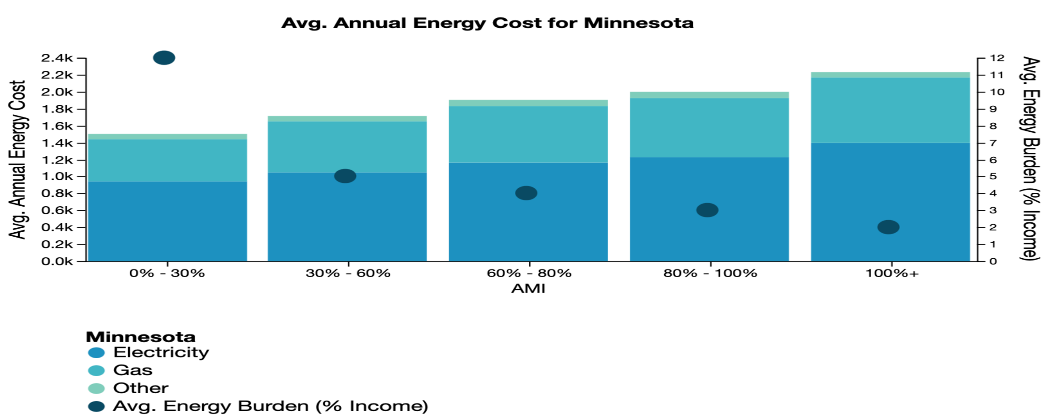
DSP's preferred plan is in the public interest considering each of the factors in Minn. R. 7843.0500, subp. 3, including in particular that the DSP plan (A) maintains or improves the adequacy and reliability of utility service; (B) keeps customers' bills and the utility's rates as low as practicable, given regulatory and other constraints; and (C) minimizes adverse socioeconomic effects and adverse effects upon the environment.

A. Access and Equity Benefits of Distributed Generation

Distributed resources owned by the individual households, organizations, and the community provide multiple pathways towards capturing ratepayer savings and increasing energy equity. The Company's modeling shortchanges distributed resources and deprives the Commission and the public of those benefits in favor of utility owned and rate-based resources. In an era where racial and economic justice are as pressing as ever, equity should be central to ensure that any approved plan minimizes cost, maximizes benefits, and ensures equitable distribution of those costs and benefits.

Low-income communities and communities of color across and beyond Minnesota already carry disproportionate economic and environmental burdens from past and current energy policy, while realizing disproportionately fewer benefits from the transition to a clean energy economy.

Energy burden, expressed as the percentage of family income spent on energy is highest for low-income households in Minnesota. *See* discussion of energy burden in Minnesota below. According to Department of Energy data,[6] the average energy burden across all Minnesotans is 2% but increases significantly for households below the Area Median Income ("AMI"). For households between 80%–100% of AMI, energy burden increases to 3%. The burden is even more pronounced for households below 30% of AMI, who spend an unsustainable 12% of their annual income on energy.



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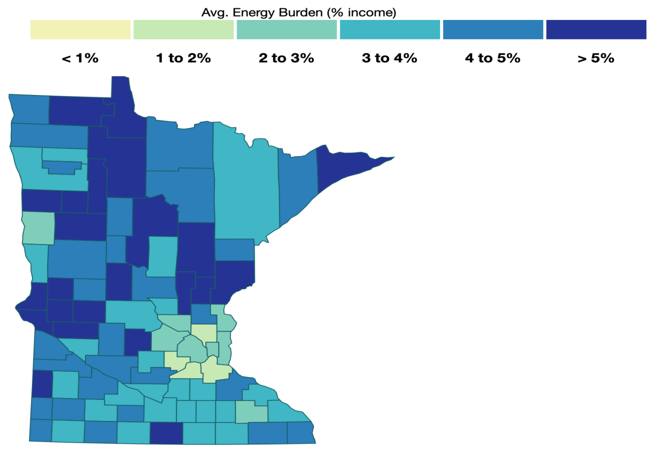
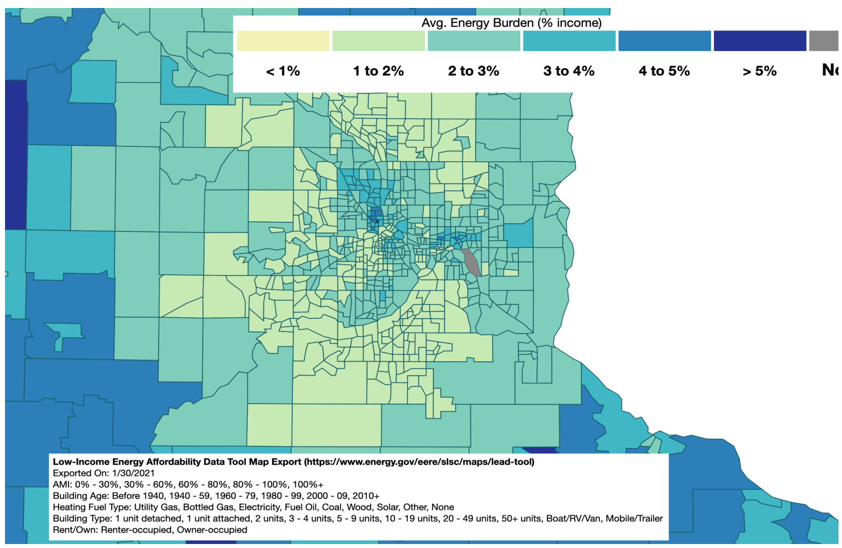
[6] Department of Energy, Data and charts from Low-Income Energy Affordability Data Tool Chart Export, Office of Energy Efficiency & Renewable Energy, https://www.energy.gov/eere/slsc/maps/lead-tool.

Statewide energy burden by county is show in this map:



While the counties in the Twin Cities Metro Area have better aggregate numbers, focusing on the region by census tract shows energy burden unevenly spread across the region.



Moreover, because of existing and longstanding social inequities, a disproportionate percentage of Minnesotans of color bear high energy burdens.[7] Low-income households and communities of color are more likely to be renters, are more likely to live in smaller homes, and are less likely to contribute to high peak loads. Under typical ratemaking practices, those customers impose lower costs to serve than other customers. Their fixed monthly charges represent a higher portion of their overall energy bills, and their energy bills cover more of their costs than other customers. In other words, low-income households and communities of color pay a disproportionate share of utility costs, subsidizing customers in larger homes that contribute more load to cost-causing peaks, who tend to be upper income and commercial customers.

These customers are also more likely to have inadequate insulation, air sealing, and ventilation, leading to other home comfort and health threats including mold and inadequately or improperly

[7] Eva Lyubich, *The Race Gap in Residential Energy Expenditures* (June 2020), https://haas.berkeley.edu/wp-content/uploads/WP306.pdf.

heated and cooled living spaces. Conservation Improvement Program ("CIP") incentives are paid for by all energy users, but most CIP incentives are designed as rebates available for homeowners, commercial businesses, or in rare cases, landlords who have adequate upfront financial resources or access to capital to pay for such rebated upgrades. Low-income households who lack the cash or access to capital to make these improvements, and renters in general must pay for these CIP programs but cannot utilize them. Plus, the same customers bear a disproportionate burden of utility shut-offs.[8] Thus, low income and people of color disproportionately pay more than their share of utility costs, bear a higher burden of costs relative to income, and have limited recourse through existing programs and incentive structures.

Those higher monetary burdens are exacerbated by the other measures of cost imposed by energy production on lower income and communities of color across the state, who also pay with their physical health by bearing the brunt of the resulting health impacts, including asthma and other respiratory diseases.[9] These customers are also most likely to have inadequate insulation, air sealing, and ventilation, leading to other home comfort and health threats including mold and inadequately or improperly heated and cooled living spaces. Utility shut-offs also disproportionately impact communities of color.[10]

It is also possible--even likely--that low income and communities of color receive lower reliability and quality of service. Currently, insufficient data exists to quantify the difference in service quality, but the Commission recently required Xcel to provide information on locational and equity related reliability data that will provide transparency into how reliability and service quality are or are not equitably distributed.[11]

Access to employment in the utility sector is inequitable, with people of color and women remaining deeply under-represented in utility careers.

1. *Equity and Energy Resource Selection*

Movement toward equity is binary. There is no neutral action or plan. The IRP process can move toward equity by evaluating future energy sources in ways that prioritize building wealth, health, and opportunity for low-income communities and communities of color. Failing to do so will, instead, exacerbate past injustices.

Distributed generation allows energy users to own and control the long-term revenue from future energy sources, allowing individuals and families to share in wealth that historically has been limited to utility investors (for utility-owned assets) and Wall Street (for energy assets operating under Power Purchase Agreements with utilities). This opportunity is further expanded through community solar and other forms of shared renewables that allow renters and low-income

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[8] NAACP, *Lights Out In the Cold: Reforming Utility Shut-Off Policies As If Human Rights Matter*, Environmental and Climate Justice Program (Mar. 2017), https://naacp.org/wp-content/uploads/2020/07/Lights-Out-in-the-Cold_NAACP-ECJP-4.pdf.

[9] Maninder P S Thind et al., *Fine Particulate Air Pollution from Electricity Generation in the US: Health Impacts by Race, Income, and Geography*, 53 Env't Sci. Tech. 14010, 14010–14019 (2019), https://pubmed.ncbi nlm.nih.gov/31746196/.

[10] *See supra* note 7.

[11] *In the Matter of Minnesota Power, Otter Tail Power, and Xcel Energy's Compliance and Annual Safety, Reliability, and Service Quality Metrics for 2019*, Docket No. 20-406 (Minn. PUC).

households and businesses who otherwise lack sufficient capital or physical space to share in the returns from renewable generation.

Customer-owned or sponsored distributed generation provides increased value by distributing the profits from renewable generation as direct customer bill savings. The value of a megawatt of solar owned by customers produces returns as direct bill savings to individual customers, whereas the value of a megawatt of utility-scale clean energy must be split between shareholders and customers, leaving less value for ratepayers. Utility scale generation also requires transmission and results in increased line losses, further reducing the value to customers. In addition to less overall savings for ratepayers, the savings that do occur from utility owned generation are not equally shared by those historically shut out of the economy. Instead, the savings flow through cost of service rules to predominantly the largest energy users, including large industry and commercial enterprises. Through community ownership of distributed generation, the savings can be more equitably shared with those previously excluded from sharing in economic wealth.

Finally, job creation and local business development opportunities are inherently greater for community-based renewable energy than for large, centralized energy systems for multiple reasons:

- A larger number of smaller projects create more jobs, both during construction and long-term during operations, than a single large project of the same total size. This creates a much more stable and sustainable long-term workforce opportunity.
- Distributed generation development also disperses business development and job creation opportunities, making jobs and enterprises more accessible to a wider range of Minnesotans. Financing is also more feasible locally for relatively smaller sized projects than large scale development, which typically requires national financial institution backing. Conversely, only very large established businesses with relatively centralized workforces can develop and only national financiers can fund large projects. It is much easier to maintain a consistent flow of projects to provide steady, dependable, jobs small and mid-sized projects than the sporadic and uneven work provided by large projects. With more overall employment and business opportunity for firms anchored in their communities to create consistent work for their neighbors, distributed generation creates a more robust economic multiplier than utility-scale generation.

Xcel Energy's proposed stimulus investments for Covid-19 response in Docket 20-492 actually confirm the benefits of community-centered renewable energy development over fewer remote and large-scale projects. Xcel compared the costs and expected costs and job creation from the proposed utility scale project at the Sherco site with a rooftop low-income solar pilot. The results are striking:

- Xcel Energy proposed to spend \$617–\$650 million on the Sherco solar project, with an expected 252–890 full-time equivalent created,[12] or 0.4–1.4 jobs per million dollars invested.

[12] Resp. and Pet., Covid-19 Relief & Recovery, Docket No 20-492 (Minn. PUC Sept. 15, 2020). Ranges for the Sherco solar project have been provided due to lack of clarity in Xcel Energy's filing. Table 8: Tranche II – Projects Pending Regulatory Process on page 19 of the filing lists the Sherco project as costing \$650 million and generating

- Xcel Energy proposed to spend ~$2 million on their low-income rooftop solar proposal, with an expected 25 full-time equivalent created, or around 12 jobs per million dollars invested.

This anecdotal evidence from Xcel suggesting between 8.5 and 29 times as many jobs per million dollars invested in rooftop distributed generation compared to utility scale solar confirms that distributed generation provides a better path to achieve a clean energy future while producing community-based and equitable economic development. It allows the development of projects that put ownership and revenue generation of clean energy into the hands of the people that use it. It allows utility bill savings opportunities to be concentrated in individual households and businesses, enabling customers with the greatest need to reduce their energy burdens. It creates steady jobs and local business development that foster stable, long-term work and a robust network of growing local businesses. Together, these are tools that enable access and equity in our energy system.

The equitable distribution of community-centered clean energy can be enhanced by additional planning and policy. The same opportunities are not available through utility scale and utility owned generation. The *Low-Income Solar Policy Guide: Principles and Recommendations for Utility Participation in Solar Programs for Low Income Customers* recently released by the Environmental Law & Policy Center, GRID Alternatives, and Vote Solar provides guidance and best practices for design and implementation of solar programs designed to serve low-income customers.

CEF has firsthand experience harnessing distributed generation as a pathway for community-based and equitable economic development for renters, low-income households, and communities of color. CEF has engaged over 800 member-owners across Minnesota, including clusters of members in North Minneapolis, residents of manufactured housing parks in Fridley, Cannon Falls, and Northfield, and renters across the Twin Cities metro area in distributed generation. CEF member-owners receive upfront benefits of community solar subscriptions much like any other community solar subscriber, but as cooperative members also enjoy the long-term wealth building benefits of profit sharing in local community solar developments. Regardless of their income or credit, CEF member-owners can share in the local economic benefits of distributed energy. Those member-owners have helped create access to jobs for communities of color, using a 50% minimum minority workforce requirement on 8 projects valued at just under $17 million to date.

B. Co-optimization of Distribution, Transmission and Generation

Co-optimization of distribution connected resources with utility scale investments provides even greater benefits.

As recently discussed by Dr. Chris Clack of Vibrant Clean Energy and others, of distributed resources on the distribution grid can be co-optimized to produce additional benefits for the larger utility grid beyond capacity and energy. For example, generation interconnected with load

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890 jobs, while Attachment A page 1 of 2 lists the Sherco project as costing $617 million and generating 252 jobs. *Id.* at 19; *id.*, Attach. A at 1.

on the distribution grid produces higher load factors on the utility scale grid, reduced peak demand, and reduced distribution infrastructure costs.[13]

We understand that the Citizens Utility Board is presenting more optimized modeling by considering co-optimization of distributed resources. We support increased utilization of such modeling by the Commission and stakeholders to the potential for high distributed generation scenarios that include the economic multiplier effect of co-optimization. DSP also support closer alignment between Xcel's distribution and resource planning functions to enable DER co-optimization (DSP address this in Section IX of these comments). And we look forward to expanding on this discussion in Reply Comments.

1. *Energy, Resource Adequacy Capacity and Reliability Benefits of Distributed Generation*

Cognizant of potential arguments that high penetration of distributed solar could create operational challenges for the Company, we commissioned Rakon Energy to evaluate several considerations for high penetration distributed generation impacts on the Company's system, including identifying opportunities within the larger Midcontinent Independent System Operator ("MISO") market, addressing challenges, and leveraging opportunities. Rakon provided five conclusions that we summarize briefly here. The full report is attached as an exhibit to these comments.

First, Rakon found that Xcel should improve its planning to include additional distributed resources and treat them as a "central element to the utility's optimized plan." In fact, due to market changes, technology development, and federal policy including FERC Order 2222, it is inevitable that greater distributed resource development will occur and will need to be accommodated by the Company's plans. Planning for greater distributed resource penetration now allows efficient optimization rather than inefficient after-the-fact adjustments to the Company's resource plans.

Second, distributed resources interconnected to Xcel's distribution system avoid the MISO queue process that is currently backed up by more than a few years and which neither the Commission nor Xcel can control. This allows Xcel to integrate higher levels of renewable resources than by focusing on utility scale, transmission-interconnected, generation that must navigate the MISO interconnection queue.

Third, MISO is currently modeling more than 3,000 MWs of distributed solar in 2021 transmission planning models. Those model runs demonstrate that a much higher level of distributed solar can be economically added to the system than Xcel is currently planning. That further confirms that the Company should revise and extend its assumptions beyond the level of distributed generation in its HDS sensitivity to determine transmission and distribution needs now.

Fourth, distributed solar, especially within the Twin Cities Metro Area, should have a higher Effective Load Carrying Capability ("ELCC") than utility scale solar connected at transmission to remote nodes. Differences in the ELCC of the same resource has been shown to vary by

[13] Clack, Christopher, et al., *Why Local Solar for All Costs Less: A New Roadmap for the Lowest Cost Grid, Executive Summary*, Vibrant Clean Energy, LLC, at 4 (Dec. 1, 2020).

interconnection node. Xcel and MISO should jointly determine the capacity value of distributed resources through a locational capacity value ELCC.

Lastly, distribution connected solar avoids distribution and transmission system costs in addition to providing resource benefits. Aligning distribution, transmission, and resource planning will reveal currently unrealized value. The Commission should require Xcel to integrate distribution, transmission, and resources as part of its IRP to meet system's reliability needs most effectively, rather than through balkanized planning. High density distributed resources will produce higher locational capacity in and around the Twin Cities Metro Area and should be considered separately from other portions of Xcel's service territory.

2. *Distribution System Benefits*

In addition to the resource and transmission benefits of distributed generation, it can also provide several categories of benefits to the distribution grid. These include capacity avoidance/deferral, ancillary services, line loss reduction, and resilience.

- Capacity: DERs reduce distribution system peak demand and can thereby defer or avoid distribution system capital investments in the short and long run;
- Ancillary services: DERs reduce the need for operating reserves, such as spinning reserves and frequency regulation, and reduce the need for voltage regulation;
- Line loss reduction: DERs inject power close to load, reducing the line losses inherent in the displaced electricity that must be transmitted over long-distance transmission lines and distribution wires; and
- Resilience: DERs diversify the energy supply mix, which can increase energy surety, or uninterrupted service by reducing vulnerabilities associated with the loss of fuels, in addition to enhancing resilience.

The degree to which DERs provide these benefits will depend on the operating profile of the distributed generation asset (including any storage paired with solar), the timing of production, and the location (within the distribution system) of the asset. However, distributed generation assets also provide long-run value to the distribution grid no matter where the asset is located.

In fact, Xcel calculates the distribution system benefits (including, in particular, avoided distribution capacity costs) of certain distributed solar as a part of its annual Value of Solar ("VOS") calculations for its CSG program (Docket No. E002/M-13-867). Under its 2021 VOS calculation, Xcel calculated the avoided distribution capacity costs associated with solar as $0.0045 / kilowatt-hour ("kWh"). While Xcel (and other stakeholders) continue to work on refining and differentiating the specific methodologies for the calculation of distribution system benefits associated with distributed solar (including locational and temporal benefits) in Docket E002/M-14-65, the work being done in those dockets leaves no doubt that there are important, quantifiable distribution system benefits associated with distributed solar.

C. *Community Solar Credits: Background on VOS and ARR*

The Value of Solar tariff mechanism was enacted in 2013. Minn. Stat. § 216B.164 requires the Department of Commerce to establish a methodology to compensate customers who provide distributed solar PV electricity generation to their utility "for the value to the utility, its customers, and society" and to submit the methodology to the Commission for approval.[14]

On April 1, 2014, the Commission approved the Department's proposed methodology to calculate the value of solar ("VOS Methodology").[15] The VOS Methodology directs utilities to annually file a new VOS tariff calculated according to the approved methodology but reflecting updated input data, and to apply the resulting rate to all customers subscribing for service under the tariff's terms during the year.

The Value of Solar has been calculated annually, but customers of CSG that were approved before 2017 receive a credit equal to the Applicable Retail Rate ("ARR"). Customers of CSG that applied after December 31, 2016 will receive the Value of Solar. There are some customers who receive credits equal to the ARR and some who receive the VOS. Xcel reports regularly on the credits applied to customers by rate class and by credit methodology.

In the Company's 2021 ARR Compliance filing, the Company described the current blend of ARR and VOS credits:

> Based on current completed projects as of December 2020 and subscription levels by customer class as of our October compliance filing, the Company estimates the average ARR pricing for 2021 to be $133.46 per MWh, and the VOS pricing at $105.70 per MWh. Assuming annual production of 1,551 MWh per MW (ac) for each of the 665 MWs of Gardens receiving the ARR and 101 MWs receiving the Value of Solar, the Company estimates 2021 Gardens subscription bill credits of over $153 million.[16]

The approved the 2020 VOS approved in the Commission's March 2020 Order contains the following elements:

Line #	25 Year Levelized Values	Distributed ($/kWh) PV Value
1	Avoided Fuel Cost	0.0301
2	Avoided Plant O&M - Fixed	0.0014
3	Avoided Plant O&M - Variable	0.0014
4	Avoided Gen Capacity Cost	0.0197
5	Avoided Reserve Capacity Cost	0.0016
6	Avoided Trans Capacity Cost	0.0175

[14] Minn. Stat. § 216B.164, subd. 10(a), (e).

[15] Order Approving Distributed Solar Value Methodology, Docket No. E-999/M-14-65 (Minn. PUC Apr. 1, 2014). The Department filed an amended and reformatted version of the approved VOS Methodology on April 10, 2014.

[16] Compliance Filing, Letter from Xcel Energy, filed in Docket No. 13-867, February 1, 2021.

7	Avoided Distribution Capacity Cost	0.0041
8	Avoided Environmental Cost	0.0394
9	Avoided Voltage Control Cost	
10	Solar Integration Cost	
11	TOTAL (LCOE)	0.1152
	LCOE of Resource Components (Sum of Lines 1-5)	0.0542

Removing the Avoided Distribution Capacity Cost, Avoided Transmission Capacity Cost, and Avoided Environmental Cost yields an LCOE of the avoided cost of resource value components of $0.0542/kWh or $54.20/MWh.

VI. Distributed Generation Potential: Examining the Potential for High Distributed Generation

Xcel's system can accommodate high penetrations of distributed generation. In 2020, the ILSR published *Utility Distributed Energy Forecasts*[17] to illustrate the shortcomings of distributed solar forecasting in Xcel's Energy Integrated Resource Plan.

The ILSR report examines the utility's forecasts for on-site solar and community solar. Xcel's modeling significantly underestimates both on-site and community solar potential and fails to recognize distributed generation's ability to cost-effectively and equitably meet systems needs in the coming years. As Vibrant Clean Energy's 2019 *Smarter Grid Study* indicates, substantial deployment of rooftop solar in Minnesota (13 gigawatts by 2050) would produce household energy savings and significantly more jobs than most decarbonization pathways.

Xcel provided almost no information about the basis for its Supplement Preferred Plan's Reference Case distributed solar forecast.[18] Xcel provides little more information about its HDS forecast, which starts with the Base Case adoption level and then projects the incremental increase in solar adoption from ten percent lower costs.[19] There is no apparent basis for these projects in Xcel's filings or data request responses. In contrast, the following analysis relies on publicly available methodologies and predicts significantly more distributed solar than Xcel's forecasts.

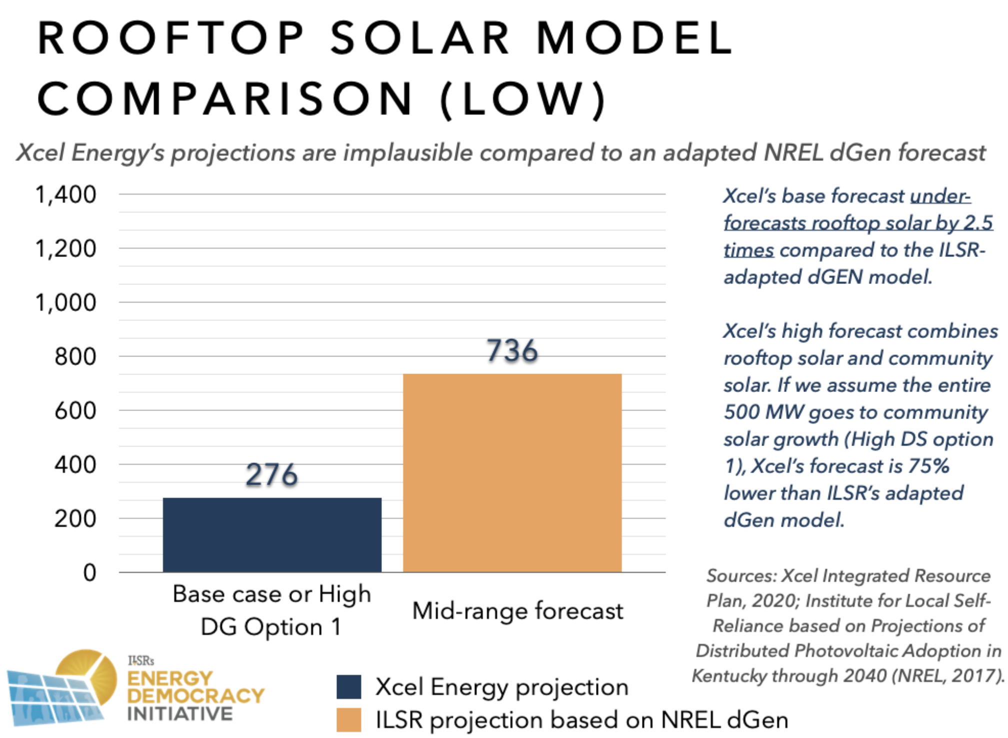
[17] John Farrell, *Utility Distributed Energy Forecasts: Why utilities in Minnesota and other states need to plan for more competition*, ILSR (July 2020), https://ilsr.org/report-utility-distributed-energy-forecasts-2020/ ("ILSR Report").

[18] Supplement Plan at 37 (stating only that "[f]or our Reference Case assumptions, we assume DG solar grows at approximately 15 MW per year after 2023").

[19] *Id.* at 38.

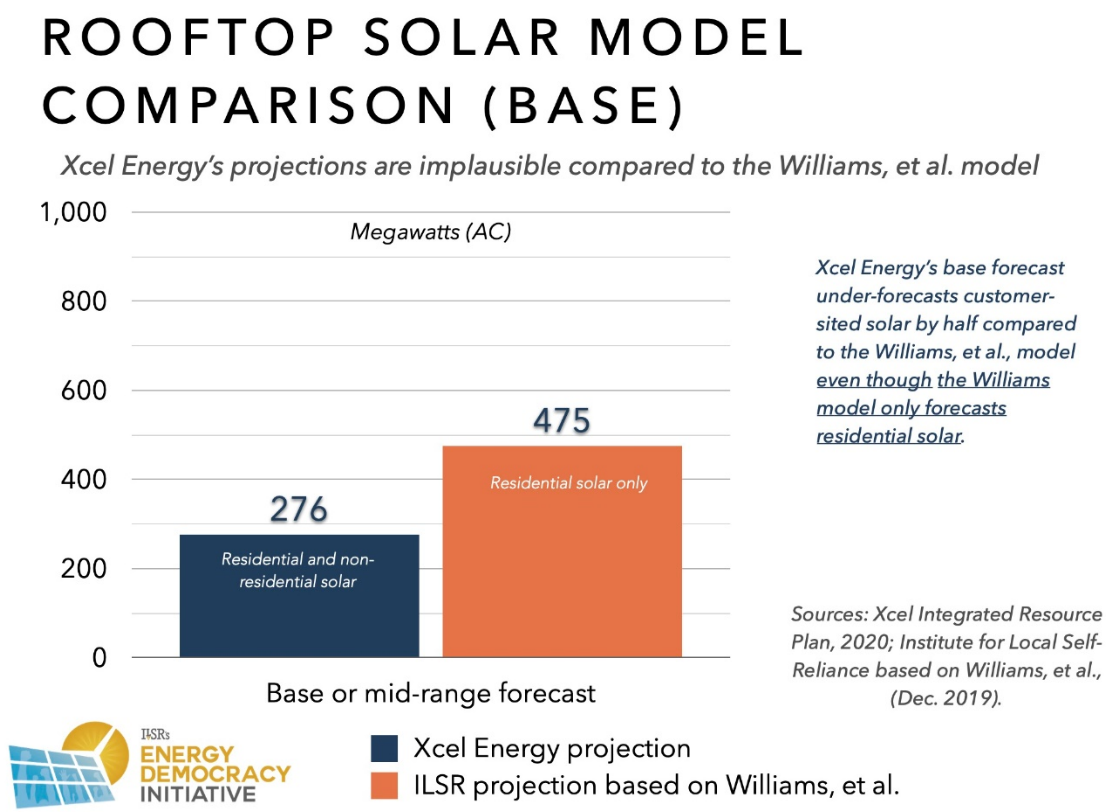
1. *Distributed Solar Model Comparisons*

ILSR compared Xcel Energy's distributed solar forecasts to alternative forecasts produced with two independent tools: (1) an Xcel/Minnesota adaptation of the NREL's dGen model of distributed solar deployment in Kentucky; and (2) application of a model developed from actual solar customer price response. NREL's Kentucky model was adapted to account for Minnesota's higher rooftop solar potential and existing deployments, compared to Kentucky, as well as Xcel Energy's share of the state's electricity customers and existing distributed solar projects. It did not also adjust for the passage of time since NREL's study, which results in increased retail electricity prices and market maturity, both of which would tend to increase the forecast results. The results of this first analysis show adoption of approximately 736 megawatts of rooftop solar photovoltaics ("PV") (megawatts AC) in Xcel's Minnesota territory by 2034, compared to the utility's estimate of only 276 MW. Even using Xcel's HDS inputs (and assuming the entire 640 MW is rooftop, community solar), the adapted dGen model still shows 21 percent more solar adoption (1,165 to 916 MW) by 2034 with similar price inputs. The following chart illustrates the base forecasts for Xcel and the adapted dGen model.



Xcel's low distributed generation forecasts also conflict with the results of a second model based on a paper in *Renewable Energy* published by Eric Williams, et al., published in December 2019. This second model projects residential solar PV adoption based on the net present value for customers. The model fits well with actual solar deployment in international (Germany, Japan) and domestic markets (California, Massachusetts, and Arizona). Notably, the Williams model projects more residential solar by 2034 than Xcel forecasts for *all* customer-sited solar (residential and commercial).

Full details of the Williams model are in the attached report. It concludes that the business-as-usual economics of residential rooftop solar should produce 475 MW of additional *residential* rooftop solar in Xcel territory by 2034 (i.e., not including commercial), compared to Xcel's estimate of only 276 MW on residential *and commercial* rooftops.[20] ILSR also compared Xcel's HDS option to a similar version of the Williams model. In this case, Xcel Energy's forecast of 916 MW of rooftop solar (assuming none of their HDS forecast goes to community solar) is still well short of the Williams model, which forecasts 1001 MW of *residential solar* before adding any growth in commercial. The following chart compares the base forecast from Xcel and ILSR's implementation of the Williams, et al., model.



As discussed below, the Williams model can be adapted to predict incremental adoption through price response that can be produced by utility actions and utilized as a resource option.

[20] Note that since Xcel's forecast and ILSR's model were both submitted in 2020, neither account for the recent extension of the federal investment tax credit at 26% for 2021 and 2022.

2. *Community Solar Model Comparisons*

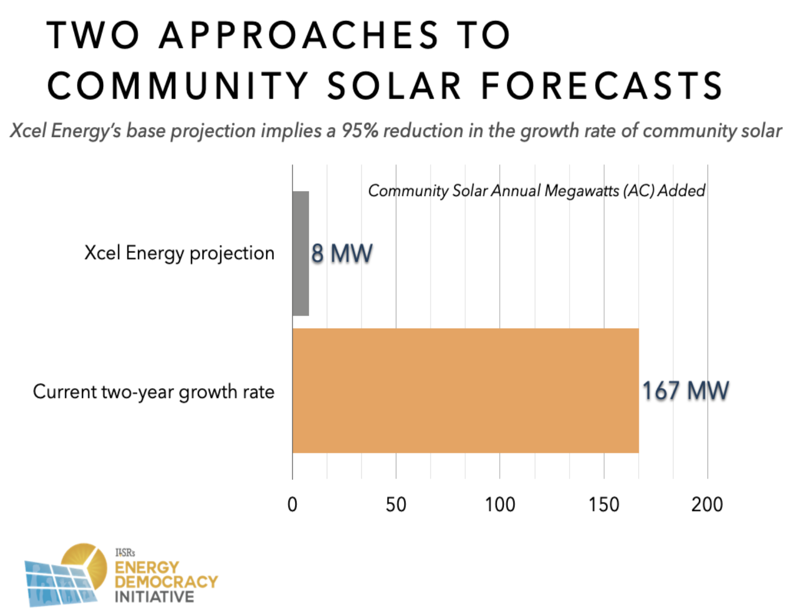
ILSR also found that Xcel's community solar forecast is also unsupported and Xcel has regularly under-predicted community solar compared to actual program performance. The utility's March 2019 reply comments in the company's bid to purchase the Mankato Energy Center estimated community solar gardens would reach 720 MW of total capacity in 2030.[21] Today, less than three years later, the actual program size had already eclipsed Xcel's 2019 projection for 2030.[22]

Xcel reply comments, 3/29/19, Docket 18-702

Table 13: Distributed Solar Forecast

Distributed Solar (Nameplate MW)				
Year	Solar Rewards	Net Metered	Community Gardens	Total
2018	29	18	246	293
2019	41	27	504	573
2020	49	37	641	727
2021	53	47	649	749
2022	56	58	657	771
2023	57	70	665	792
2024	57	83	673	813
2025	56	96	681	834
2026	56	109	689	854
2027	56	122	697	875
2028	55	135	705	895
2029	55	147	713	915
2030	55	160	720	935

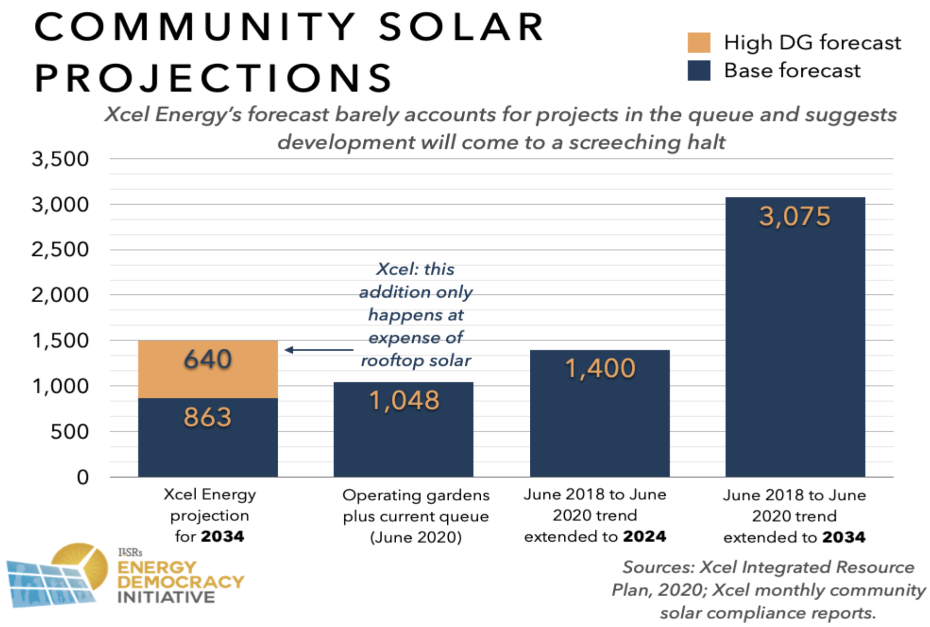
Xcel's Supplement Plan forecasts 863 megawatts of community solar by 2034. Operational community solar capacity was 757 MW on December 1, 2020. Xcel's 2034 forecast is only 106 MW higher, implying a growth rate of only 8 MW per year, compared to the rate of 167 MW per year during the last two years--a 95% decrease in annual community solar participation. This underestimate is also discussed above in Section III.B. of these comments.



[21] Reply Comments, Attach. A at 13, Docket 18-702 (Minn. PUC Mar. 29, 2019).

[22] John Farrell, *Why Minnesota's Community Solar Program is the Best*, Institute for Local Self-Reliance (Feb. 5, 2021), https://ilsr.org/minnesotas-community-solar-program/.

There is also *already* more CSG capacity reflected in the current application queue than Xcel projects by 2034. ILSR's report found that if historical trends continue even for the next five years, Xcel's base case forecast is low by nearly 50 percent *and* 10 years late. If historical trends continue until the end of the forecast period in 2034, Xcel's most ambitious forecast is still short by 50%. If the current growth rate of community solar continues, CSG additions will produce just shy of the 3,500 MW of utility-scale solar Xcel proposes to build.



3. *Mitigating Factors*

ILSR's 2020 report outlines three factors that could reduce the rate of community solar growth. None is likely to result in the level of decline that Xcel's forecast assumes.

- The value of solar has decreased by 17 percent in the past five years, largely due to lower fossil gas prices. However, few forecasts show lower gas prices in the future (and in fact, it's hard to imagine prices falling further when existing prices are not enough to make existing operations profitable).[23]
- Interconnection is another potential barrier. For one, as the recent $1 million penalty imposed on Xcel illustrates, Xcel has made it difficult for solar developers to get interconnection processed in a timely and cost-effective manner.[24] Additionally, ILSR's initial review of hosting capacity suggests that for at least the next five years, hosting capacity is unlikely to present a major barrier (especially as the figures do not account for

[23] Kathy Hipple et al., *Frackers cut capex to $5.8 billion during third quarter, lowest level in a decade*, Institute for Energy Economics and Financial Analysis (Dec. 8, 2020), https://ieefa.org/ieefa-u-s-frackers-cut-capex-to-5-8-billion-during-third-quarter-lowest-level-in-a-decade/.

[24] Mike Hughlett, *State regulators fine Xcel Energy $1M over dispute with solar developers*, Star Tribune (Jan. 21, 2021), https://www.startribune.com/state-regulators-fine-xcel-energy-1m-over-dispute-with-solar-developers/600013483/.

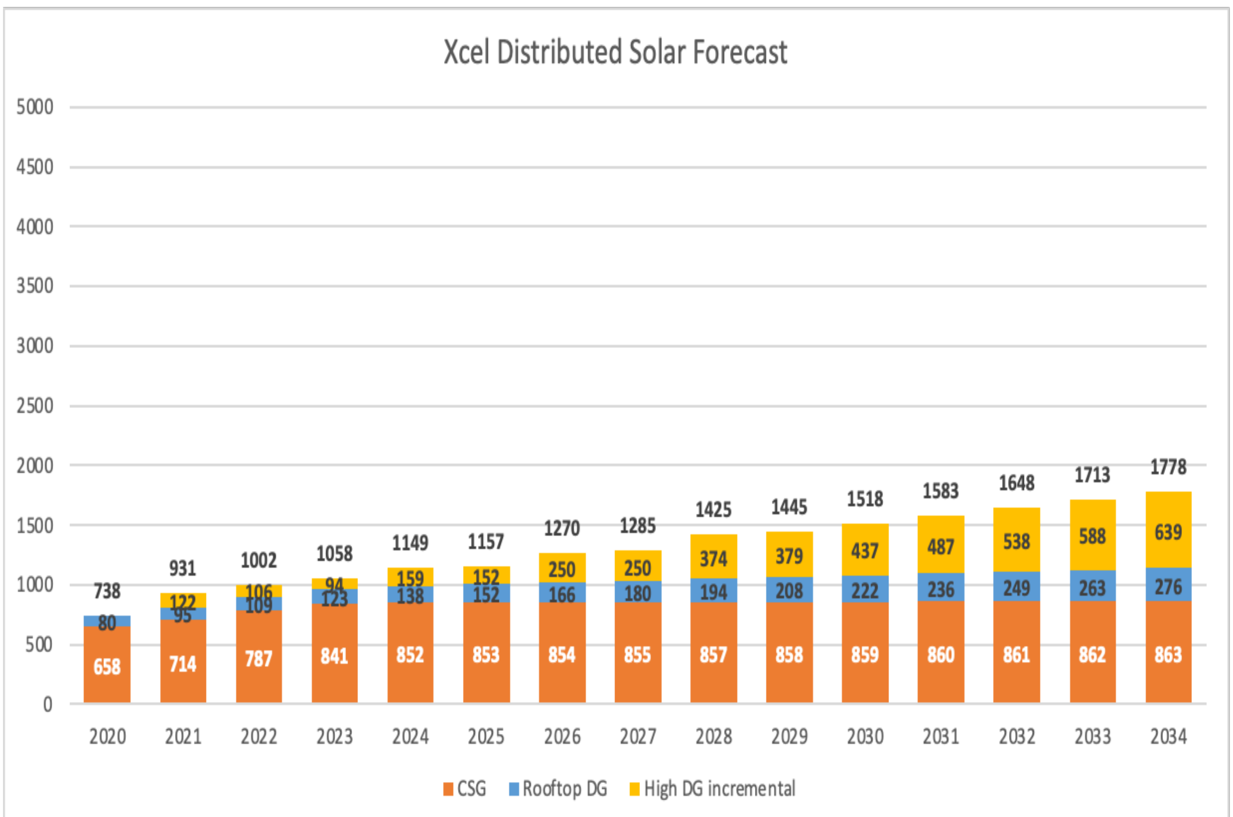
daytime minimum load, energy storage, inverter loading ratios, or other mitigation measures).

- The expiration of federal solar tax credits could also reduce community solar development. However, in its original analysis, ILSR found that the trend in declining installed costs compensates for the decline in tax credit rates. Additionally, since publication of ILSR's report, the federal government pushed back the expiration of the federal solar tax credit by two full years.

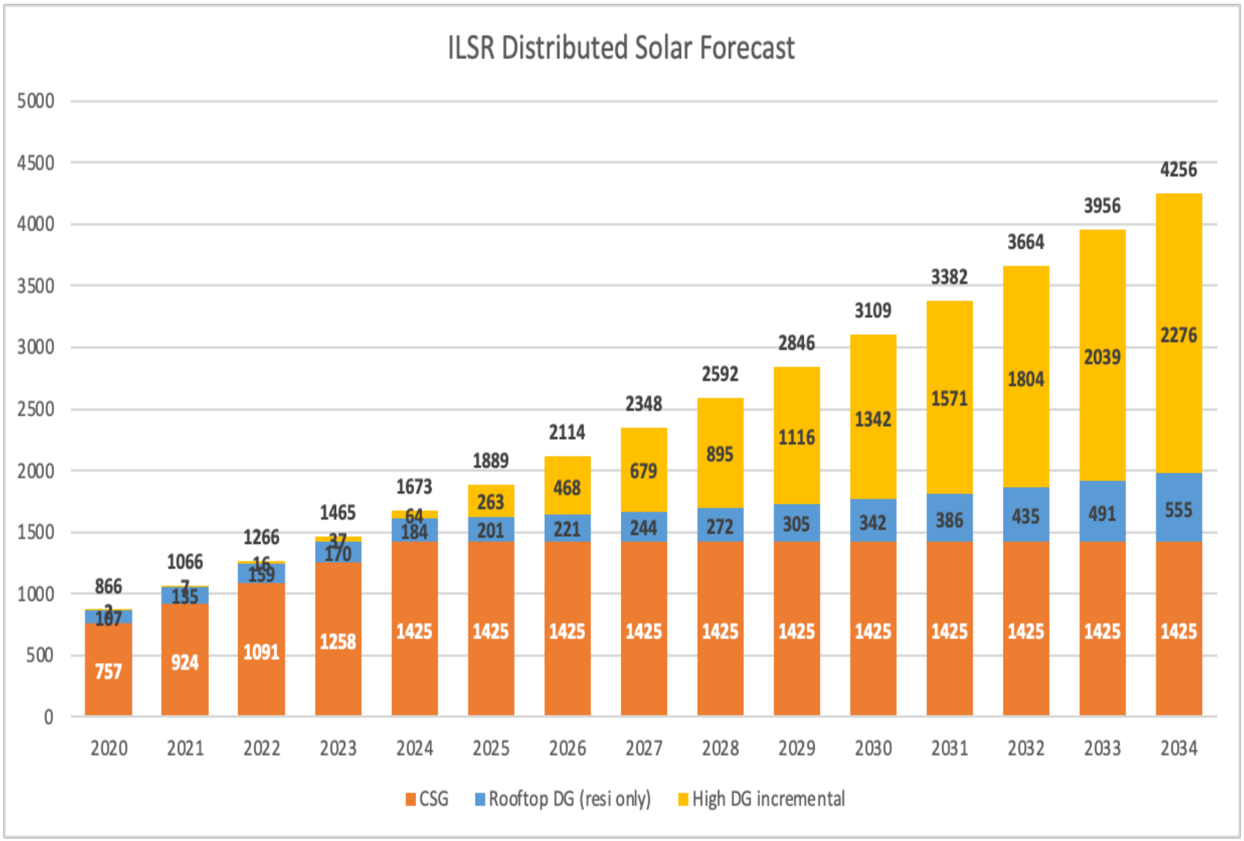
None of these factors, even if they occur, would produce the 95 percent reduction in community solar deployment implied by Xcel's filing. Given the shortcoming of Xcel's customer-sited distributed solar analysis, even Xcel's HDS forecast is insufficient to make up for the shortfall in community solar as a reasonable estimate of combined baseline distributed solar.

4. Summary of ILSR Report Forecast for Rooftop and Community Solar

Overall, Xcel Energy's forecast is far short of likely actual distributed solar deployment. The two charts, formatted as Figure III-2 from the Supplemental IRP (but with an updated axis), show the gap.[25] The base forecasts differ by several hundred megawatts and still do not account for ILSR's forecast ignoring non-residential distributed solar nor the unlikely scenario of a cessation in community solar development. The high distributed solar forecasts differ by 2,500 MW, with ILSR's still omitting non-residential solar.



[25] Supplement Plan at 39.



5. State Efforts to Support Wholesale Distributed Generation

In 2001, Minnesota adopted a distributed generation tariff intended to encourage wholesale distributed generation projects 10 MW and smaller (the Public Utilities Commission adopted rules in 2004).[26] Unfortunately, the tariff has not produced any project development.[27]

Subsequently, in 2005, a state-sponsored study identified enormous available capacity on the lower-voltage transmission system to inject electricity from dispersed wind energy projects. Additionally, that year the state adopted the community-based energy development law, creating a tariff to support wholesale distributed generation from community-based projects by front-loading contract compensation.[28] Further state grid studies published in 2008 and 2009 reinforced the idea that new, distributed renewable energy capacity could be added without expanding the transmission network.

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[26] Order Establishing Standards, Docket No. 01-1023 (Minn. PUC Sept. 28, 2004), https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={EB5DCE72-415A-4767-965F-35BA37EC59EA}&documentTitle=59785.

[27] Mot. of the Minnesota Solar Energy Industries Association, et al., Docket No. 01-1023 (Minn. PUC Mar. 23, 2018), https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={808A6762-0000-C71D-AFBC-BAEA4C78BBC7}&documentTitle=20183-141397-01.

[28] Community-Based Energy Development (C-BED), Institute for Local Self-Reliance, https://ilsr.org/rule/community-based-energy-development-c-bed/.

In addition to specific tariffs and studies, the chapter of state statute focused on distributed energy says that the laws should be construed to provide, "maximum possible encouragement to cogeneration and small power production."[29]

These state efforts are supplemented by the federal Public Utilities Regulatory Policies Act ("PURPA"), which requires utilities to buy electricity from wholesale renewable energy generators at their "avoided cost." Once again, however, Minnesota's poor implementation has not matched its legislative intent, resulting in continued significant barriers to distributed wholesale generation.

6. Earlier Studies Have Shown Significant Available Grid Capacity

In 2005, a study of the West Central region of Minnesota identified a theoretical maximum of 3,500 MW of new wind capacity that could be added across 57 electrical substations, if connected to lower voltage distribution lines. At the time, the first 1,900 MW were forecast to replace gas generation, with additional capacity, up to the 3,500 MW, backing out (at the time) less expensive coal-fired generation from Wisconsin.[30]

In particular, the study showed that 800 MW of new generation could be added with zero to no upgrades to the existing transmission infrastructure. Up to 1,400 MW could be added with transformer and transmission upgrades totaling about $100 million (far less than adding new high-voltage transmission lines). Even the maximum amount, 3,500 MW, had forecast costs of $375 million, in comparison to the over $1 billion required to add 1,050 MW of new transmission capacity with the since-completed CapX2020 project.[31]

The West Central study also provided a quick scan of four other Minnesota regions. If a similar portion were feasible (about 40% of the maximum), it indicated the potential to add 5,500 MW of distributed generation to the state's grid system at a modest system upgrade cost.

The West Central study was followed by a legislatively ordered statewide distributed generation study, completed in two phases in 2008 and 2009. The project took several months as it had to build a first-ever cross-utility model for examining lower voltage transmission power flows. Phase I identified twenty dispersed sites across the five state planning zones where a cumulative 600 MW of distributed energy generation (limited to 10 to 40 MW) could be added with zero transmission upgrade costs (unfortunately, the modeling exercise did not examine how much more could be added beyond the legislature's 600 MW ask).

Phase II of the study, released in 2009, examined adding a second 600 MW but made a major change in assumptions by including all projects in the MISO interconnection queue with signed interconnection agreements. Although there was plenty of local capacity shown available, the transmission constraints shown by the MISO assumption limited the aggregate opportunity to 50 MW **with no upgrades**. However, the study concluded that, "The statewide total to implement

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[29] Pet. for Reconsideration by the ELPC and ILSR, Docket No. 19-9 (Minn. PUC Mar. 12, 2020) ("Petition for Reconsideration"), https://www.edockets.state.mn.us/EFiling/filing/viewServedDocument.do?method=showPoup&fileName=2020.03.12+19-09+FINAL+Petition+for+Reconsideration.pdf&folderType=permanent&submissionNo=20203-161193.

[30] John Bailey et al. *Meeting Minnesota's Renewable Energy Standard Using The Existing Transmission System*, ILSR (Nov. 2008), https://ilsr.org/wp-content/uploads/files/meetingminnesotares.pdf.

[31] *Id.*

all the system upgrades necessary to achieve 600 MW of [distributed renewable generation] in Minnesota is just over $121 million."[32]

B. Hosting Capacity Analysis

In its latest approved hosting capacity report (Docket No. 19-685), Xcel Energy reported a maximum hosting capacity of 1,307 MW. This figure was used as a limit on modeled community solar capacity. The following explains the rationale behind using this as a broad-brush estimate of system capacity to host large, distributed generation projects like community solar gardens.

As noted in ILSR's report, there are at least three factors that could reduce available hosting capacity: feeders with less than 1 MW of open capacity, substations with less capacity than the cumulative capacity on connected feeders, and the geographic location of feeders relative to potential subscribers.[33] On the other hand, as noted in the report and above, there are also mitigating factors. Hosting capacity does not account for daytime minimum load (which could be served by distributed generation before tapping into hosting capacity), nor does the report account for mitigations measures such as energy storage, inverter loading ratios, etc. Given these competing factors, it is reasonable to use the reported maximum hosting capacity figure as a potential limiting factor on community solar development.

VII. Distributed Generation as a Resource Model

As noted above, Xcel made an initial, if minimal, effort to evaluate some of the benefits of distributed generation through its HDS sensitivity. However, as also noted above, the Company's initial effort suffers from several flaws. It dramatically overstated to costs of distributed generation as a resource to the Company by including the costs borne by the distributed generation owner in the model. It under-projected the amount of cost effective distributed solar available. And it only tested higher (although still too low) levels of distributed generation with a limited set of other inputs, including low load and fuel costs.

Our proposed Distributed Generation as a Resource proposal offered incremental distributed generation (over and above the level assumed in the Company's preferred portfolio plan) to the EnCompass model. In order to do that, we priced additional increments of distributed solar at the utility's cost, rather than the all-in cost borne by the solar owner, so the model could select additional distributed solar. We utilized the Williams price response model to determine the cost decline for solar required to incent the next block of distributed solar uptake by customers. We monetized that price decline as if an incentive that the utility could offer to achieve the requisite cost to the customer to produce the associated level of solar installation.

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[32] Dispersed Renewable Generation Transmission Study Phase II, Vol. I, at 112, Docket No. E999, DI-08-649 (Sept. 15, 2009), https://www.lrl.mn.gov/docs/2009/mandated/090918/volumei.pdf; Dispersed Renewable Generation Transmission Study, Vol. I, Docket No. Docket No. E999,DI-08-649 (June 16, 2008), https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={4B0348B8-D8F4-4050-87A5-48388A473BD4}&documentTitle=5320805.

[33] ILSR Report at 17.

A. *BTM / Rooftop / Customer Sited Distributed Generation Adoption Model*

We adopted a simplified model proposed by Eric Williams, Rexon Carvalho, Eric Hittinger, and Matthew Ronnenberg in the journal *Renewable Energy* in December 2019.[34] That model relies on a robust relationship between the NPV cost per kilowatt for a customer to install solar and the likely level of customer adoption:

> Empirical analysis for five regions (three U.S. states: Arizona, California, and Massachusetts; and two countries: Germany and Japan) from 2005 to 2016 shows a consistent relationship between annual adoption per million households and NPV.[35]

Essentially, it uses inputs of existing, available residential rate structures and then uses a best-fit model to several existing domestic and international PV markets to link net present value to megawatt adoption. By reducing the NPV to the population of eligible customers (e.g., through an incentive) the utility can produce a predictable increase in distributed generation adoption.

Utilizing the Williams et al. empirical model we determined the amount of price reduction necessary to produce different increments of distributed generation adoption. The DG Resource concept translates the value of distributed generation to a customer into customer's adoption level.

While those price reductions could occur naturally as further technology advances and economies of scale reduce the cost of distributed generation to a greater degree than assumed, the utility can also accomplish them and produce the corresponding customer price response by providing an incentive to lower the the net cost to the level that will induce the desired level of customer distributed generation adoption.

ILSR built a Minnesota-specific version of the Williams et al. model with the following assumptions:

- System size (kW): 4
- Cost per Watt (gross): $3.50
- Capital cost: $14,000
- Subsidy, initial year: 26% Investment Tax Credit
- Annual production: 5000 kWh
- Self consumption: 100% (all net metered)
- Retail price: $0.12
- Inflation: 2%
- Interest rate: 5%
- Feed-in Tariff ("FIT") price: n/a

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[34] Williams et al.

[35] *Id.* at 570.

- Solar life: 25 years
- FIT term: 25 years (net metering)
- K - 2000 MW per million households
- Mu - 7100 per kilowatt ("kW")
- Sigma - 4110 per kW

In addition to these values, ILSR also added:

- 0.5% solar production degradation per year, per industry standards
- A baseline of 667,980 single-family, detached homes in the Minneapolis-St. Paul seven county metropolitan area (American Community Survey)

ILSR provided two forecasts using the Williams et al. model. The Base Forecast included the following stipulations:

- The Federal Investment Tax Credit for residential projects expires as previously scheduled.[36] (Note: we have not updated the results to reflect the two-year extension passed by Congress at the end of 2020).
- Minnesota's Solar*Rewards program expires as scheduled.
- The cost of solar declines at an annual rate of 5% (matching the five-year average).[37]

To identify the *utility cost* of modeled residential solar adoption, we selected incentive levels (in dollars per MWh) and used the Williams et al., model to identify adoption curves. We selected resource net cost reduction (incentive level) increments ($0, $10, $20, $30, $35 and $40) that were in the range of costs available to the model. It was assumed that other resources would be selected at cost levels above $40/MWh. An incentive level of $0 represents the difference between the Xcel base distributed generation inputs and the distributed generation adoption model.

Non-residential distributed solar was estimated to be 71 percent of residential adoption, based on a national trend of relatively lower non-residential capacity. The 71 percent figure was from Solar Energy Industries Association for the entire country in 2019.

Based on the calculations, we developed a DG Resource model that was offered to EnCompass by the Sierra Club modeling team at each of the five different incentive levels in each year. The quantity of megawatts available in any given year were derived from the Williams et al. model. This chart illustrates the price/quantity relationship at each increment for each of the years of the Plan.

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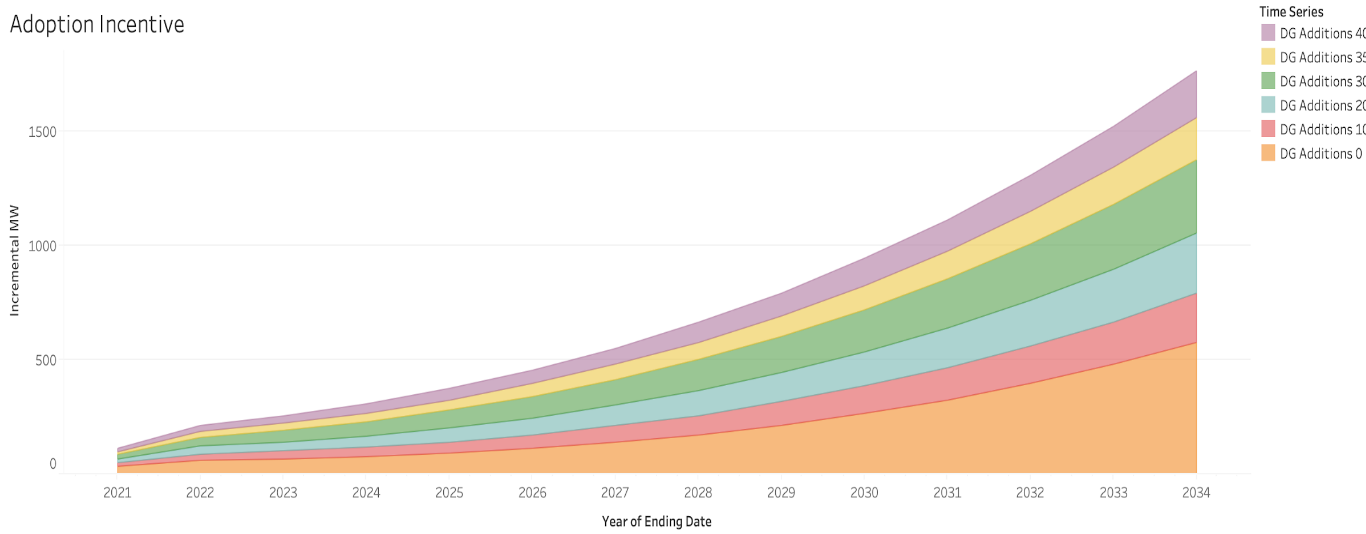
[36] John Farrell, *Congress Gets Renewable Tax Credit Extension Right*, ILSR (Jan. 5, 2016), https://ilsr.org/congress-gets-renewable-tax-credit-extension-right/.

[37] Galen Barbose and Naïm Dargouth, *Tracking the Sun: Pricing and Design Trends for Distributed Photovoltaic Systems in the United States, 2019 Edition*, Berkeley Lab (Oct. 2019), https://emp.lbl.gov/sites/default/files/tracking_the_sun_2019_report.pdf.



Adoption Incentive - Table

	Year of Ending Date														
Time Series	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Grand T..
DG Additions 40	14	26	33	41	50	61	73	86	101	118	137	157	179	203	1,279
DG Additions 35	12	23	29	37	45	55	66	78	92	107	124	143	163	185	1,159
DG Additions 30	21	40	51	63	77	94	112	134	158	184	214	247	283	322	2,000
DG Additions 20	17	33	41	51	62	75	90	108	127	149	174	201	231	265	1,624
DG Additions 10	14	26	33	40	49	60	72	86	102	120	140	163	188	215	1,308
DG Additions 0	33	60	65	74	89	109	136	169	211	262	322	393	476	572	2,971
Grand Total	111	208	252	306	372	454	549	661	791	940	1,111	1,304	1,520	1,762	10,341

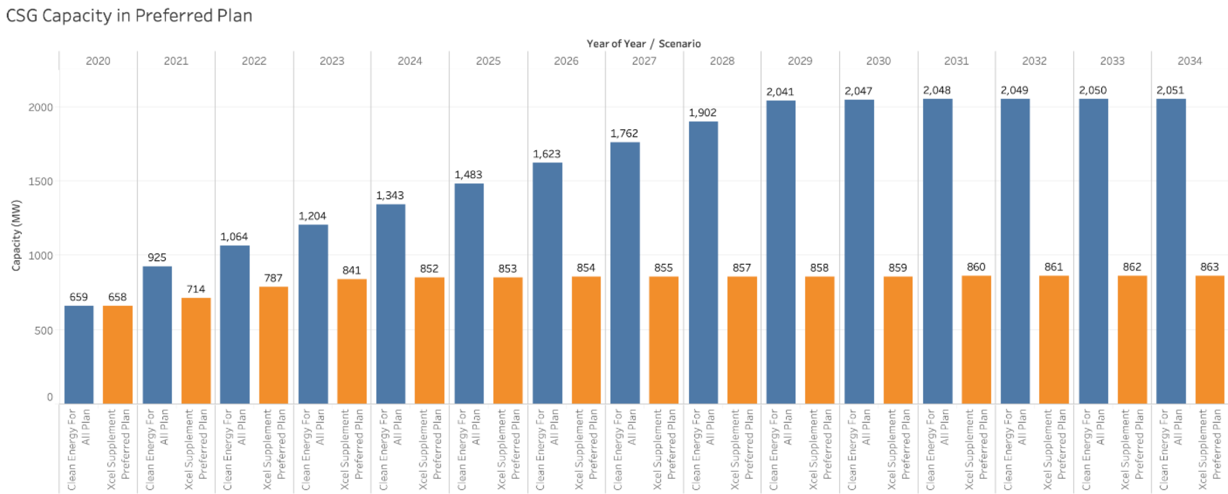
The totals at the bottom of each year column show the total distributed generation that is offered to the model in any given year. So, for example, in 2022, with no additional incentives, 65 MW would be expected to be built in the Xcel service territory. However, if the model selected both the DG Additions 10 and the DG Additions 20, it would add 59 MW (26 MW for DG Additions 10 plus 33 MW for DG Additions 20) for a total of 124 MW of distributed generation selected by the model.

To be clear, this is what is *offered* to the model. Results of the modeling are discussed below in the Modeling results section.

B. Community Solar

The CEFA alternative plan model assumes that CSGs will continue to be developed at approximately the same rate as historically until it reaches a constraint based on the capacity available in the most recent hosting capacity analysis. The underlying rationale in specifying this level of CSG adoption to the model is that as a separate voluntary, uncapped program, customers and developers will continue to participate in this program at a rate consistent with empirical observation. CSG growth is driven by private incentives based on the difference between project costs (which are probably flat on net) and the VOS. Xcel's choice to "flat-line" CSG is not supported by evidence or statute.

Our model therefore assumes community solar will be added at a rate of approximately 140 MW per year until it reaches a cumulative installed base of approximately 2,040 MW in 2029, at which point it levels off. Cumulative CSG in the Clean Energy for All Plan compared to Xcel's Preferred Plan is shown in this table



Costs for CSG in Clean Energy for All Plan are handled differently between the Company baseline CSG capacity and for incremental additions added in the DSP model. As discussed in the TRADE SECRET comments, we disagree with the resource cost modeled by the Company for its baseline CSG capacity.

We model incremental CSG additions at zero cost because CSG are a unique resource in the context of integrated resource planning. CSG is a freestanding program whose adoption is driven by customer interest and developer capacity. In that way, the same costs are incurred and resources added without regard to the rest of the utility's resource mix. So long as the costs of non-selectable resources are held constant between scenario runs, the precise level does not affect portfolio selection. Excluding CSG Additions costs from the model for all runs produces the actual difference in costs based on resource choices available.

In addition, we note that the credits to customers for the VOS rate and the Applicable Retail Rate options for CSG include a number of values that are not reflected in the model. The Applicable Retail Rate reflects the utility's full embedded cost of service to the customer, which includes many non-resource related expenses that are not contemplated in the resource expansion model. Likewise, the VOS rate includes the same non-resource costs as the Applicable Retail Rate plus externality values that are already considered later in the integrated resource plan. To include those externalities values in the VOS as costs in evaluating CSG as a resource would double count them.

The cost minimization problem of a capacity expansion model used in integrated resource planning minimizes total recoverable costs to the utility and should not include the costs borne voluntarily by individual customers. For example, the energy efficiency supply curve used in the IRP includes only the incremental system costs of energy efficiency and not the private costs to individual customers who invest in efficient devices. Analogously, the cost of distributed generation relevant for optimization in the IRP should be the net incremental costs to ratepayers (recoverable costs less system benefits). Moving forward, all CSG additions are compensated at the VOS, which sets recoverable costs at exactly incremental system benefits. Therefore, CSGs compensated at the VOS should not be modeled as a cost in the IRP since the tariff design for the CSG program already precisely compensates CSGs as a marginal resource.

In order to understand the value of the CSG Additions that we forecast based on the limited values used in the model without double counting or including costs of services the model does not test (e.g., distribution capacity and distribution line losses), we compare the cost of a modeling run that includes the CSG Additions at zero cost to an alternative run that is identical except that it removes the CSG Additions from the pre-set portfolio. The difference in the PVSC of the two runs represents that value of the CSG, limited to the energy and capacity values tested by the model, and should provide a basis for the Commission to evaluate the benefits that the CSG brings to reducing overall system costs.

C. Discussion of Uncertainties and Assumptions

1. Incentive Design and Equity

The proposed DG Resource offered to the model assumes that an incentive will be offered that has a defined cost to the utility. However, the design of this incentive is not specified in this proposal. Currently, the Company offers the Solar*Rewards program, which has some impact on adoption. The distributed generation adoption made the same assumptions about the phase out of the Solar*Rewards program as the Company's base assumptions.

The Williams et al. model predicts distributed generation adoption based on the net present value of a solar installation to a prospective distributed generation owner. The variables that drive the NPV calculation include:

- Installed cost
- Ongoing cost
- Energy production
- Production (kWh) incentive
- Capacity (kw) incentive
- Federal tax credit
- Renewable energy credit value
- Energy prices
- Financing assumption

Conceptually, any of these variables could be adjusted to change the NPV to arrive at the target NPV that will drive the desired level of distributed generation adoption. The variable controllable directly by the utility is the direct, up-front incentive. It is also the most customer friendly and amenable to adaptation to address equity concerns and meet the needs of low-income customers.

The incentive design must prioritize equity and access for low-income and Black, indigenous, and communities of color. In laying out his plan to secure environmental justice and equitable economic opportunity, President Biden pledged that 40% of the investment in the clean energy transition would be targeted to disadvantaged communities.[38]

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[38] *The Biden Plan to Secure Environmental Justice and Equitable Economic Opportunity*, https://joebiden.com/environmental-justice-plan/.

As discussed above, distributed generation provides a unique opportunity to target the benefits of distributed generation to reduce energy burden and increase energy independence for communities. Under the DG Resource design proposed in the model specification, the higher incentive levels could be targeted to achieving the environmental justice goals described here.

We stand ready to work with the Company and the Commission to design a DG Resource incentive that would meet the resource requirements selected by the model and advance equity and access goals.

2. *Adoption model accuracy in utility resource planning*

As previously discussed, in traditional resource planning, distributed generation is typically ignored or treated as something that "happens to" the utility. However, evidence confirms that net present value to the customer has a direct, predictable, impact on adoption levels. To the extent that the utility can impact net present value to the customer, it can increase distributed generation adoption levels to help meet resource needs. We anticipate that utilities will argue that they don't have the ability to change customer adoption patterns with sufficient accuracy and predictability. However, there is no evidence that customer price response is less predictable than the many underlying assumptions for a resource plan.

Customer load growth and future fuel prices are notoriously unpredictable but drive significant resource decisions. Electric vehicle uptake is an assumption in Xcel's model, but has at great, if not greater, uncertainty. Unlike those assumptions, customer distributed generation adoption has an empirical basis. The Williams et al. paper, upon which the model is based, demonstrates a robust relationship between the sole explanatory variable (NPV) and adoption. The model was derived from a regression of actual (empirical) data and the resulting relationship was found to be statistically significant.

Finally, the William et al. study on which this model is based showed meaningful and strong results. The PV diffusion model presumes that aggregation adoption of solar panels is determined by one variable, the average Net Present Value experienced by customers in a given year in a given region. Clearly there NPV will vary by consumers within a region and many other factors could influence individual decisions, such as wealth and educational level. However, aggregate adoption of consumers in a region empirically correlates with the adoption model using only NPV as an explanatory variable. The model was calibrated with 47 data points from 5 regions (California, Massachusetts, Arizona, Germany and Japan), the figure indicates a clear correlation between the model prediction and empirical data.

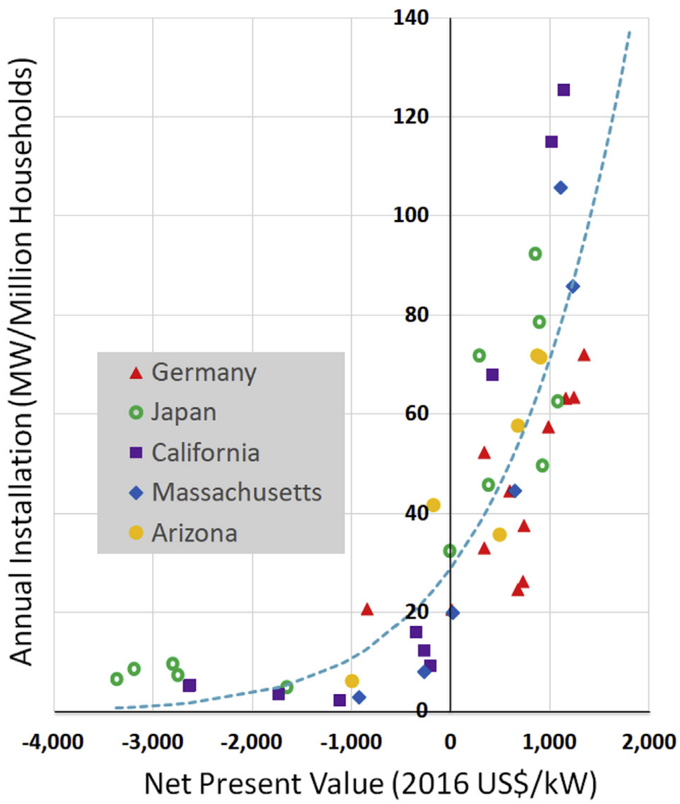


Fig. 1. Annual residential PV installations versus Net Present Value for homeowners in five regions (Germany, Japan, California, Massachusetts, Arizona). Each data point re flects an annual figure for the region, years treated are 2005 2016 for Germany, Japan and California, 2011 2016 for Massachusetts and Arizona. The dotted line is the fit from the error function model, Equation (4).

As expected, there are differences between model prediction and actual adoption, partly due to simplicity of the model, but also driven by noisiness in the underlying aggregate data Considering all data points, differences between predicting and empirical annual adoption varied from -91% to +323% for individual years. This range indicates that model is a very rough estimate of adoption in any particular year while more precisely predicting the expected trajectory of adoption over time and in the aggregate. This is reflected in the result that the average deviation of prediction from data for all 47 data points is significantly lower, 20%.

3. *Distributed Generation Visibility and Planning*

A megawatt of solar in 10 kW increments on 100 rooftops spread around the Company's service territory has exactly the same resource value as a megawatt sitting in a field somewhere. In fact, because of geographic diversity, it is likely better. It is to be expected that at any given time, a certain percentage of small distributed generation projects will be offline for one reason or another, but that is a probabilistic problem, especially at very low levels of penetration, that can easily be accommodated. The typical operating mode of all solar, whether utility scale or distributed, is to operate at full capacity whenever it is available. The utility does not need controls to manage the resources since there is no need for curtailment. As the Xcel service territory approaches the level of distributed generation penetration at which it becomes an operational concern, the Company, the Commission and MISO will be developing programs to exercise flexibility. It is possible that could occur with the distributed generation penetration selected by the model in our modeling results. We acknowledge and will work with the Company on that, but it should not deter us from beginning along that path while the operational impacts are low and easily manageable.

VIII. Modeling Results

A. Summary of the Sierra Club Alternative

Our proposed Alternative Plan is the same as the Sierra Club Alternative Plan ("SC Alternative"). We collaborated with the Sierra Club to design the DG Resource inputs which Sierra Club's modeling team incorporated into its modeling work. Sierra Club's Alternative Plan includes the DG Resource as a resource option available to the utility. Sierra Club's comments will describe its modeling in further detail and its Alternative Plan, the CEFA plan, compared to Xcel's Preferred Plan.

The most significant changes to the inputs and approaches compared to the Company's plan were:

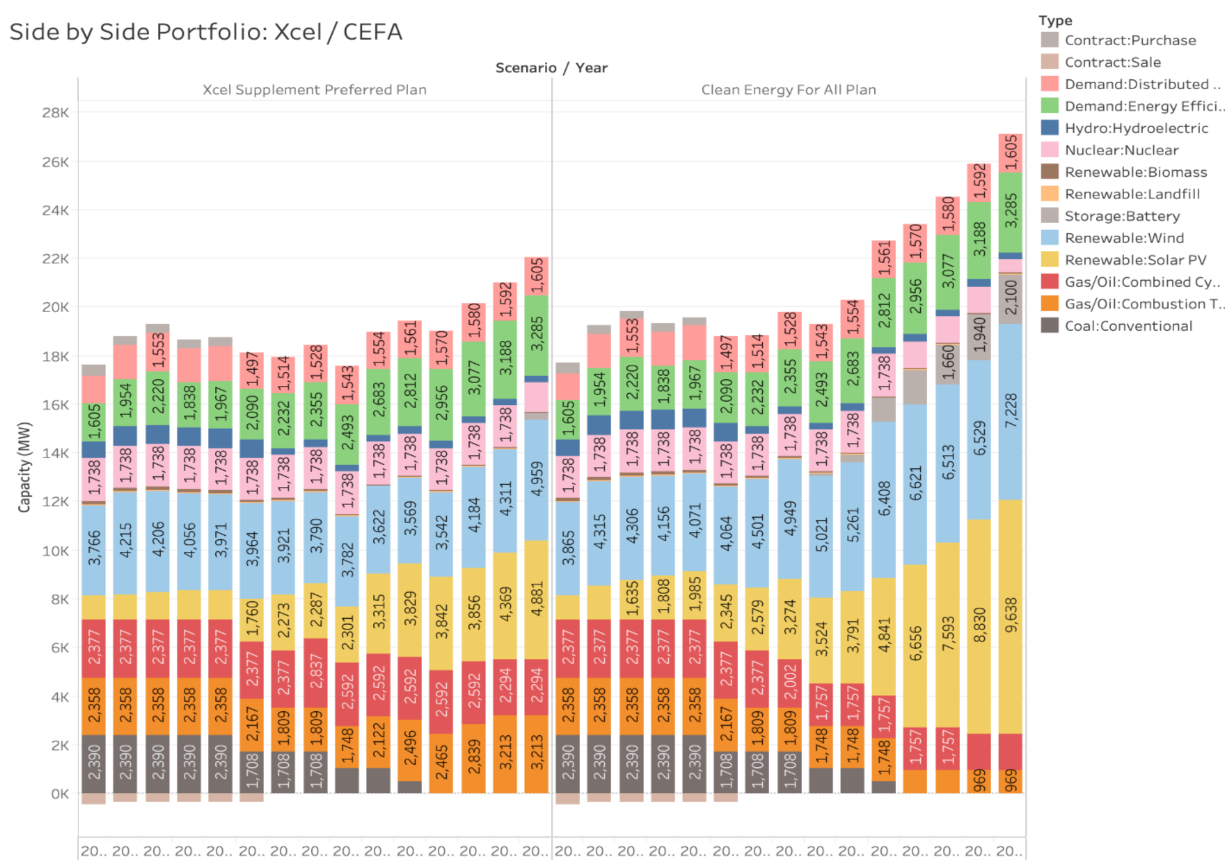
- adoption of updated input assumptions for renewable energy costs based on updated Annual Technology Baseline;
- did not "force" building the Sherco Combined Cycle plant, instead allowed the model to select it if economic;
- changed the size of the renewable energy increments offered to the model so that it it could select smaller incremental additions (from 500 MW for utility scale solar in Xcel's modeling to 20 MW and 150 MW (differently price) in the CEFA);
- added a hybrid solar + storage resource option;
- adjusted interconnections costs to be consistent with findings by Vibrant Clean Energy;
- offered the DG Resource;
- adjusted CSG assumptions to be consistent with capacity and past assumptions; and
- analyzed scenarios that include extension of Monticello and retirement at end of current license.

The Sierra Club team then compared various combinations of approaches and input assumptions to develop the preferred plan, the CEFA plan. While the Sierra Club Comments provide a thorough analysis of comparisons between the Company's Supplement Preferred Plan and CEFA, we summarize the relevant comparisons here and will provide greater depth on the results relative to the differences in the solar buildouts between the Supplement Preferred Plan and the CEFA plan.

Scenario	Extended Monti NPV ($million)	No Monti Extension NPV ($million)
Xcel's Preferred Plan ("Scenario 9") (With corrected RE price assumptions and updated approved portfolio)	$37,395	N/A
Clean Energy For All Plan	$35,465	$35,190
Delta from Xcel's Preferred Plan	($1,930)	($2,205)

The CEFA plan that includes the Distributed Solar Coalition's DG Resource offerings reduces the Present Value of Societal Costs metric compared to the Company's Supplement Preferred Plan by $2,205 billion.

The Company's capacity portfolio for each year of the plan is compared between the two scenarios in this chart:



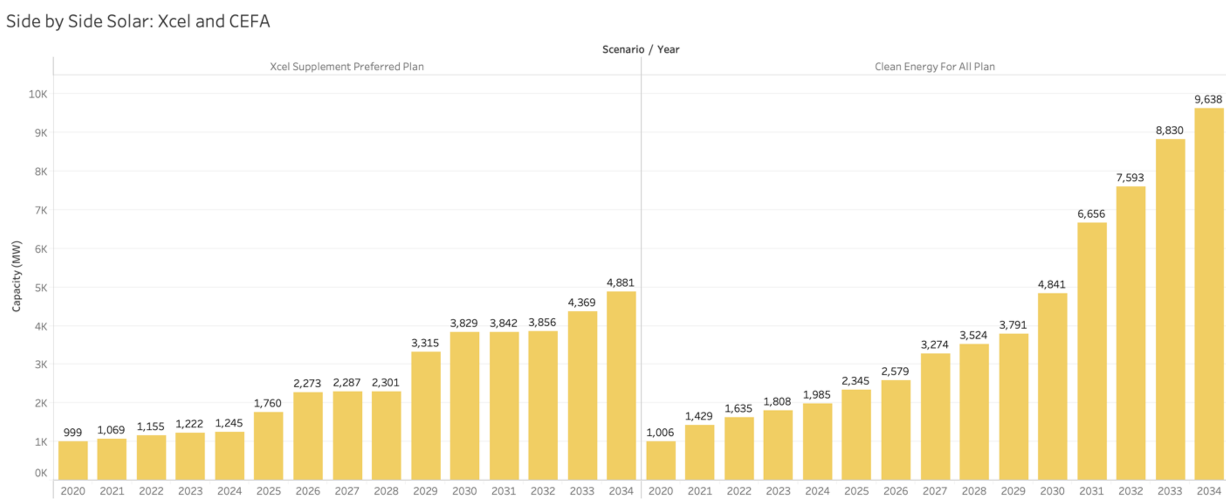
Of note in these two portfolios is the divergence between in solar energy and reliance on natural gas (both combined cycle and combustion turbines) in the out years.

With regard to the natural gas, in the final year of the plan, the Company's Supplement Preferred Plan still has 5,507 MW of natural gas (3,213 MW of CCGT and 2,294 MW of NGCT). As noted above, the Company does not officially select combustion turbines ("CT"), but instead refers to Firm Peaking resources. We have chosen to present those additions as CTs since that is how they are modeled in EnCompass. In the proposed alternative presented in Sierra Club Clean Energy for All Plan, there are 1,459 MW of NGCT and 969 MW of Natural Gas Combined Cycle.

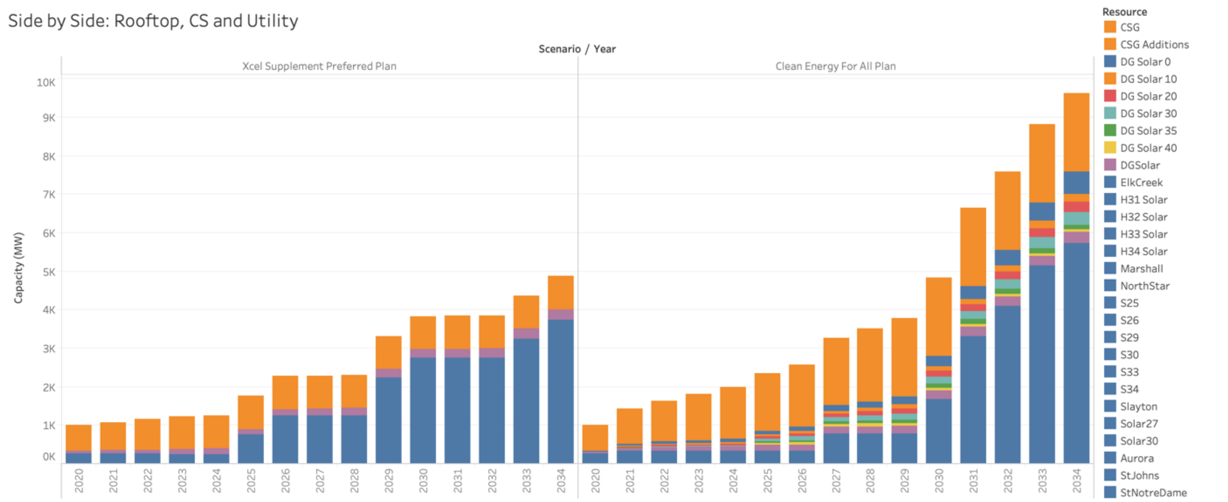
The remainder of the analysis of the results will focus on the solar, and in particular distributed generation. We endorse the analysis, findings, and recommendations of the Sierra Club in support of Sierra Club's Clean Energy for All Plan.

B. Solar in Xcel Preferred Plan vs CEFA with DSP Distributed Generation Resource Approach

The total amount of solar in either plan is significant. However, by making distributed generation available as a resource and adding a more realistic forecast of CSG under current statute, the Clean Energy for All Plan ends up with significantly more total solar. The CEFA plan would result in a total of 1,851 MW of rooftop distributed generation, 2,051 MW of CSG, and 5,735 MW of utility scale solar by 2034.



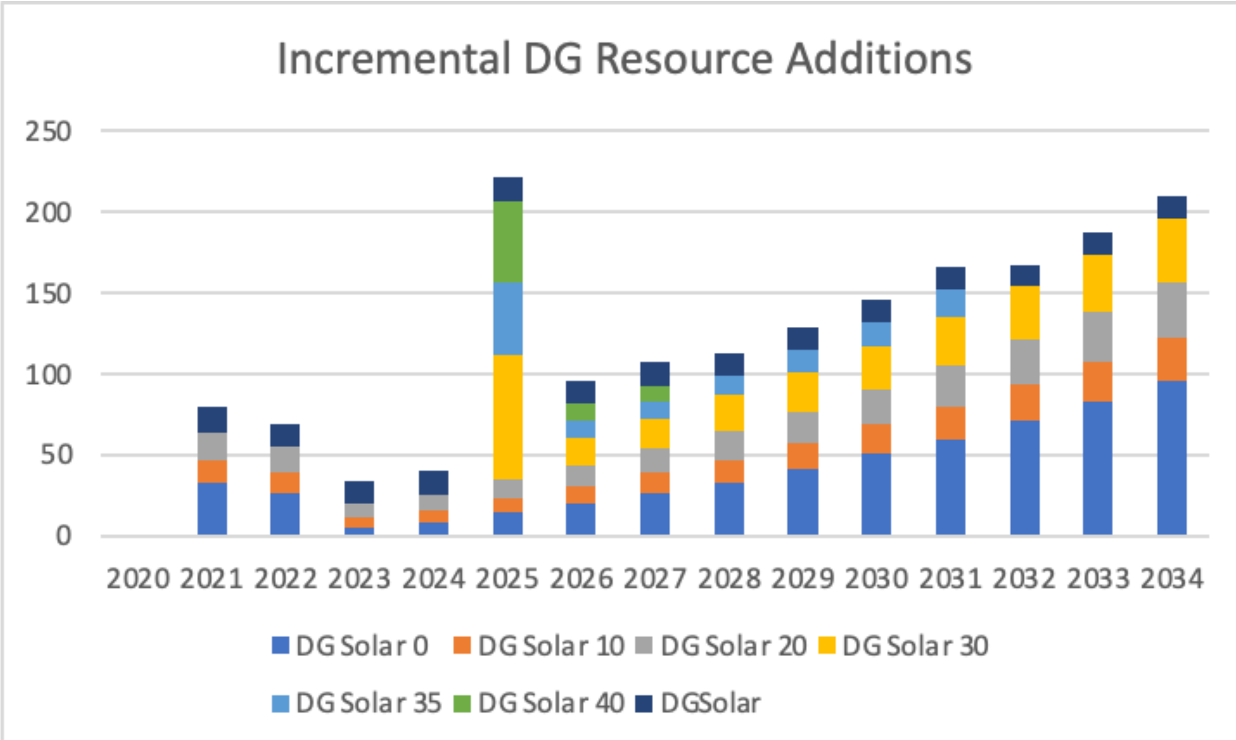
As has been intimated, a significant amount of the difference is that the EnCompass model selects much but not all of the distributed generation that is offered in the optimization because of the low cost.



The rooftop solar in the Clean Energy for All Plan breaks down as shown in this table:

The DG Solar shown in this table (in purple at the bottom of the legend) represents the Company's baseline distributed generation assumptions. The other resources represent the distributed generation resources selected by the model in the years in which they are selected.

The table below shows that the model selects different amounts of the distributed resources in different years:



IX. Alignment of Utility Planning Processes

In these comments, DSP have explained the importance and reasonableness of a high-distributed generation (and DER) resource portfolio for Xcel. The integration of high levels of distribution grid-connected resources, including distributed solar PV, while co-optimizing those resources with bulk system generation in order to minimize costs and maintain reliability, requires changes to Xcel's current approach to distribution system planning.

The Company acknowledges that it is at the early stages of aligning its resource planning and distribution planning processes. It states, in Appendix I, that:

> "The Berkeley Lab report, Distribution Systems in a High Distributed Energy Resources Future, Planning, Market Design, Operation and Oversight proposes a three-stage evolutionary structure for characterizing current and future state DER growth, with stages defined by the volume and diversity of DER penetration – plus the regulatory, market and contractual framework in which DERs can provide products and services to the distribution utility, end-use customers and potentially each other.[39] The report emphasizes the need to ensure reliable, safe and efficient operation of the physical electric system, DERs and the bulk electric system, which correlates to Minnesota utility requirements under Minn. Stat. § 216B.04 to furnish safe, adequate, efficient, and reasonable service.

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[39] Paul De Martini and Lorenzo Kristov, *Distribution Systems in a High Distributed Energy Resources Future*, Future Electric Utility Regulation (October 2015), https://emp.lbl.gov/publications/distribution-systems-high-distributed.

> The report describes Stage 1 as having low adoption of DERs, where the focus is on new planning studies when DER expansion is anticipated, which also correlates to where we are in Minnesota presently. Supplemental IRP, Appendix I at 35.

The Company used identical language in its most recently approved Integrated Distribution Plan. Integrated Distribution Plan, Docket No. E002/M-19-666 (Minn. PUC Nov. 1, 2019, approved July 23, 2020). It further described the current interaction between the Company's distribution and resource planning activities as follows:

> Currently, the distribution and transmission planning groups meet twice per year, and additionally work together as their respective planning processes impact or rely on one another. For example, distribution planning supplies transmission planning with substation load forecasts that are an input into the transmission planning process. These two groups also interact when distribution planning identifies the need for additional electrical supply to the distribution system - and similarly with interconnections, distribution is on point, and involves the appropriate planning resource as needed.

Id. at 265.

And the Company clarified the key distinctions between the objectives of the distribution and resource planning functions as follows:

> Distribution planning, like IRPs, charts a path to meet customers' energy and capacity needs, but is more immediate and subject to emergent circumstances because distribution is the connection with customers. Unlike IRPs, five-year plans are considered long term in a distribution context; and, IRPs are concerned with size, type and timing, whereas the primary focus of distribution planning is location. Thus, distribution loads and resources are evaluated for each major segment of the system - on a feeder and substation-transformer basis - rather than in aggregate, like occurs with an IRP.

Id.

The Company is correct that its system is currently at low levels of DER penetration; that greater alignment between Xcel's resource and distribution planning should generally track increasing DER penetrations, and that even with greater alignment, meaningful differences between the constraints and objective functions associated with each planning process may remain. However, some of the traditional separations between the Company's distribution and resource planning functions must change - and change quickly, in order for Xcel to rapidly expand DER deployment over the forecast period. In other words, alignment between resource and distribution planning must lead - not lag - increasing DER penetration. This is because a highly distributed resource portfolio can deliver cost savings to Xcel's customers *if* those distributed energy resources are co-optimized with Xcel's bulk system resources.

As Xcel itself acknowledges, on the distribution system, *location* and *timing* matters, and can impact the costs that its customers ultimately bear. Where distribution-connected resources are co-optimized with the bulk system, those resources can help provide system flexibility, shift demand, help avoid or defer distribution and transmission costs, and integrate higher levels of renewables.[40] In addition, the Rakon Energy report shows that the distributed generation located on the distribution systems would have higher ELCC than utility-scale resources.

Anticipating a highly distributed and decentralized future, and in order to ensure that DER provide optimal value to the power system, Xcel should take the following actions as a part of its resource and distribution planning processes:

1. **Set DER deployment targets consistent with approved IRP.** Distribution planning must be responsive to Xcel's resource planning efforts, in order to ensure that Xcel's distribution grid is prepared to integrate the appropriate levels of DER. The Commission should therefore direct Xcel to explain, in its forthcoming IDP, how its distribution plan will put the Company on track to meet the level of DER deployment in its approved IRP.
2. **Conduct advanced forecasting to better project the levels of DER deployment at a feeder level, using Xcel's advanced planning tool**. The Commission certified Xcel's Advanced Planning Tool in Docket E002/M-19-666. Xcel described this Tool as giving the Company greater visibility into its distribution system, allowing it to forecast DER and load at a more granular level. Xcel also stated that it anticipated using the Planning Tool in time for its 2021–2025 planning cycle. The Commission should direct Xcel to explain, in its forthcoming IDP, how it is using its Advanced Planning Tool to improve distribution system visibility.
3. **Proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with DER deployment targets**. Xcel is required to conduct and file hosting capacity analyses that provide an indication of distribution feeder capacity for DER, streamline interconnection studies, and inform long-term distribution planning. Xcel should use this analysis to plan distribution system investments necessary to increase hosting capacity on circuits where it expects increasing distributed generation deployment, or where adding DER would provide grid value.
4. **Improve Non-wires Alternative analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of DERs to address discrete distribution system costs**. As a part of its Integrated Distribution Planning effort, Xcel is required to screen its planned distribution projects to determine whether those projects might be avoided or deferred by "non-wires alternatives." Several commenters in Xcel's integrated distribution planning (and grid modernization) dockets have explained that Xcel's non-wires alternatives analysis must improve in order to allow customer- and third-party owned DER a meaningful opportunity to compete with traditional utility-owned distribution grid infrastructure (and thereby deliver savings to customers). The Commission should direct Xcel to strengthen its non-wires alternatives analysis by conducting market solicitations for deferrable/avoidable distribution system projects.
5. **Plan for aggregated DERs to provide system value including energy/capacity during peak hours**. Several utilities and states are exploring the use of aggregated DERs as

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[40] Southern California Edison's *Reimagining the Grid* whitepaper provides a good example of a utility's plan to better align its distribution and resource planning processes, such that its distribution grid is prepared for the increasing levels of DER required by the utility's long-term resource portfolio. Southern California Edison, *Reimaging the Grid* (Dec. 2020), https://www.edison.com/home/our-perspective/reimagining-the-grid html.

"virtual power plants" to provide an array of bulk and distribution system services. In California, the Staff of the Public Utilities Commission has proposed a pilot DER tariff that would allow the utilities to leverage aggregated customer- and third-party owned resources that respond to dispatch signals communicated by the utility.[41] The Commission should direct Xcel to explore similar customer DER programs in its forthcoming Integrated Distribution Plan as a tool to avoid or defer traditional distribution upgrades and complement targeted procurements associated with the Company's non-wires alternatives analysis.

X. Conclusions and Recommendations

- Xcel should redo its modeling with assumptions and updates consistent with the overall findings of the CEFA plan.
- Specifically, Xcel should revise its preferred plan to adopt the DG Resource into its modeling and allow the model to optimize the use of distributed generation
- The Commission should revise require utilities to consider distributed generation as a resource in future integrated resource plans for all utilities
- Cost of DG Resource should consider and attempt to quantify distribution system benefits of distributed generation and incorporate into the modeling
- Design DG Resource incentive programs that ensure distributed generation programs provide equitable access to low income and Black, indigenous, and communities of color that have disproportionately borne costs of unjust and inequitable energy decisions
- The Commission should take steps recommended in Section IX to better align distribution and resource planning, including:
    - Set DER deployment targets consistent with approved IRP.
    - Conduct advanced forecasting to better project the levels of DER deployment at a feeder level, using Xcel's advanced planning tool.
    - Proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with DER deployment targets.
    - Improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of DERs to address discrete distribution system costs.
    - Plan for aggregated DERs to provide system value including energy/capacity during peak hours.

XI. Authors (alphabetical)

- Timothy DenHerder-Thomas, Cooperative Energy Futures

[41] *See* Decision Adopting Pilots to Test Two Frameworks for Procuring DERs that Avoid or Defer Utility Capital Investments, Rulemaking 14-10-003 (Cal. Pub. Util. Comm'n Jan. 5, 2021).

- John Farrell, Institute for Local Self Reliance
- Will Kenworthy, Vote Solar
- Nikhil Vijaykar, Environmental Law & Policy Center

XII. Acknowledgements

The DSP wish to acknowledge the following for their assistance and advice in preparing these Comments. First, the Sierra Club team provided invaluable assistance in translating our vision for distributed generation as a resource into a reality. Thanks especially to Laurie Williams at Sierra Club, Rachel Wilson and Divita Bhandari at Synapse Economics, Tyler Comings at Applied Economics Clinic and Michael Goggin at Grid Strategies. Thanks also to Drs. Eric Williams of the Rochester Institute of Technology (and his colleagues Rexon Carvalho, Eric Hittinger, and Matthew Ronnenberg) study of a novel approach to distributed generation adoption inspired the model structure. Thanks also to Dr. Gabe Chan at the University of Minnesota for providing thoughts and feedback on community solar garden structure in Minnesota. Of course, all errors and omissions are our own.

XIII. Attachments

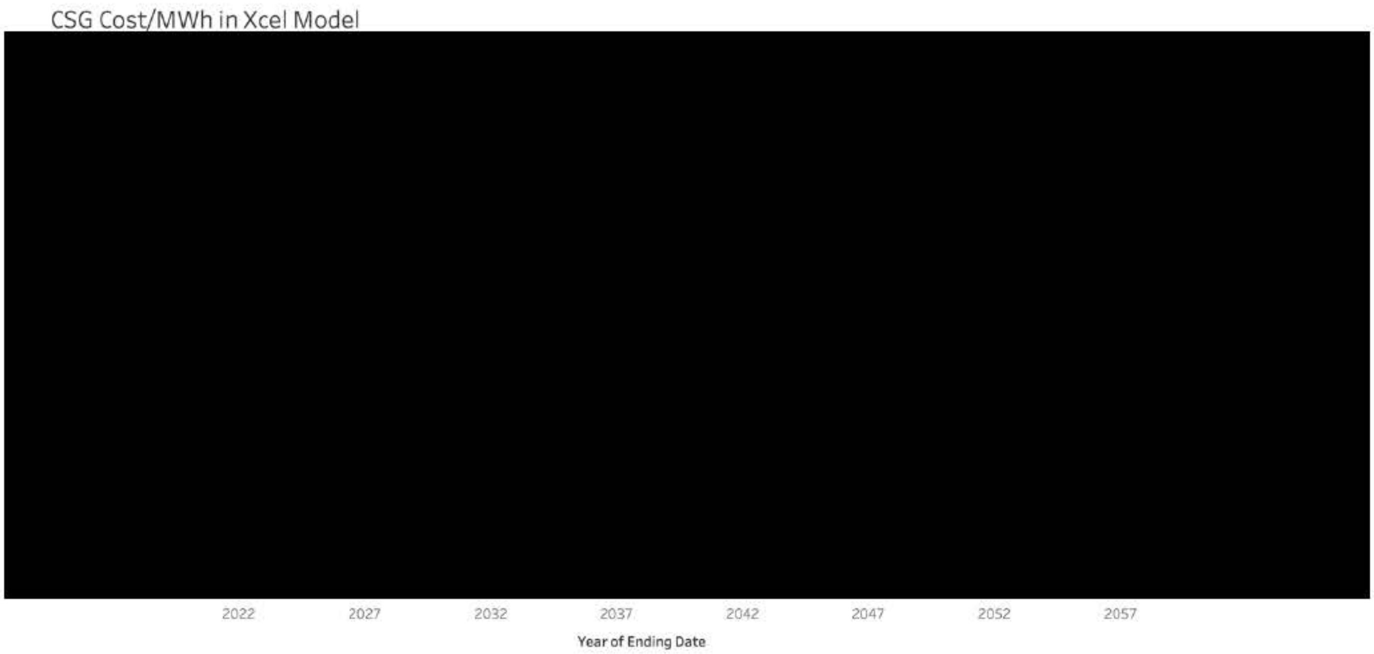
- ILSR Report
- Low-Income Solar Policy Guide
- Rakon Report

Trade Secret Supplement to Joint Comments of Vote Solar, Institute for Local Self Reliance, the Environmental Law and Policy Center, and Cooperative Energy Futures

XIV. Community Solar Modeling

A. Community Solar Costs Xcel's Modeling and Results

Xcel's Community Solar Garden ("CSG") modeling assigns a cost per Megawatt hour that appears to be based on [redacted] The following chart shows the annual expense (identified as variable O&M) the Company assigns for CSG generation in its EnCompass modeling.



The CSG cost appears to reflect [redacted] However, EnCompass only optimizes and compares costs for production and transmission. Instead, Xcel should have included [redacted] By using [redacted], Xcel's model [redacted] cost for CGS.

Moreover, because the VOS calculation already includes [redacted] that are separately assigned in the EnCompass modeling, those portions of the CGS credit value should not be included in the CGS costs input to the model.

CSG costs used as model inputs should be limited to the portion of CGS credit value reflecting:

[redacted]

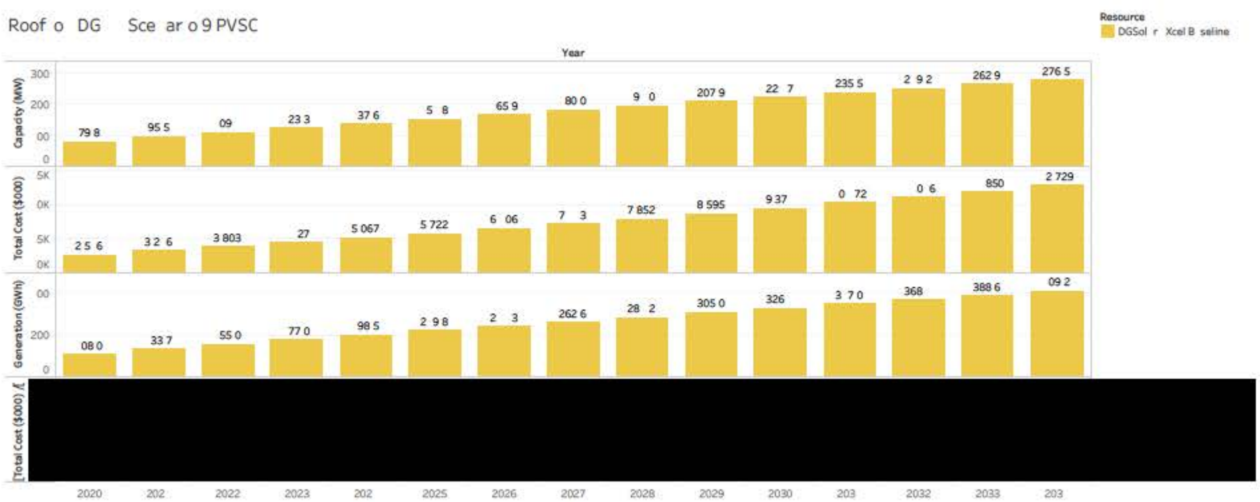
i [redacted]

B. *Community Solar Modeling of Additions in EnCompass*

Since CSG is an uncapped program, developers are likely to continue to develop projects until reaching system hosting capacity limits. To determine the "cost" of CGS for purposes of determining the present value of societal costs, we conducted a differential cost comparison. We conducted a model run containing incremental CSG capacity and a run without increment CSG capacity. The difference in the cost between the run with only Xcel's CSG baseline and the run with Xcel's baseline plus CEFA CSG Additions reflects the "avoided cost" of additional CSG.

XV. DG Rooftop Cost Modeling

The Company's baseline distributed generation buildout included the following solar capacity, cost, generation, and average cost during the plan period:



The IRP Supplement narrative suggests that it utilized a levelized cost of energy ("LCOE") of $46.12/MWh (LCOE) for utility-scale solar, $61.16/MWh for distributed commercial solar, and $92.16/MWh for distributed residential solar in its modeling. However, the Company's inputs to the Encompass model reflect a different assumed cost for distributed solar. The baseline DG generation run inputs indicate an average cost starting at [redacted] the end of the planning period.

The basis for the Encompass DG solar cost inputs is unclear from Xcel Supplement Preferred Plan. We suspect it was based on [redacted]. If that is the case, it is consistent with our DG as a Resource method, which treats only the utility's expense as the cost of distributed solar.

We agree with Xcel's choice not to use LCOE value as a model input (despite the contrary statement in Xcel's narrative), which would improperly include customer capital expenditure for distributed generation as if a utility cost. Only the costs to the [redacted]—reflects a correct model input. Thus, although the exact basis for Xcel's solar DG cost input is unclear, [redacted] and therefore an appropriate input. However, as explained in our main comments, Xcel's modeling analysis incorrectly forced DG solar into the model rather than allowing the model to select DG resources.

ILSR Report

Utility Distributed Energy Forecasts:

Why utilities in Minnesota and other states need to plan for more competition

By John Farrell
July 2020

ILSR INSTITUTE FOR Local Self-Reliance

Table of Contents:

About the Institute for Local Self-Reliance

The Institute for Local Self-Reliance (ILSR) is a national nonprofit research and educational organization founded in 1974. ILSR has a vision of thriving, diverse, equitable communities. To reach this vision, we build local power to fight corporate control. We believe that democracy can only thrive when economic and political power is widely dispersed. Whether it's fighting back against the outsize power of monopolies like Amazon or advocating to keep local renewable energy in the community that produced it, ILSR advocates for solutions that harness the power of citizens and communities. More at **www.ilsr.org**.

About the Author

John Farrell is co-director of the Institute for Local Self-Reliance and directs the Energy Democracy Initiative. He is widely known as the guru of distributed energy and for his vivid illustrations of the economic and environmental benefits of local ownership of decentralized renewable energy. He hosts the Local Energy Rules podcast, telling powerful stories about local climate action, and frequently discusses the ownership and scale of the energy system on Twitter, **@johnffarrell**. Contact him at **jfarrell@ilsr.org**.

Thanks to David Morris, as always, for his thorough review and to several other reviewers who prefer to remain anonymous. All errors are my own.

For weekly updates on our work, sign up for the Energy Democracy newsletter:

http://bit.ly/ILSREnergyNews

Cover photo credit: John Farrell, a SolarCity community solar array near Scandia, Minn., that is co-located with a honey bee farm.

Related publications from ILSR's Energy Democracy Initiative:

- **Why Minnesota's Community Solar Program is the Best**: a monthly update on the status of Minnesota's community solar program, launched in December 2014. Data from Xcel Energy.
- **Minnesota's Solar Gardens**: a report from Vote Solar, MnSEIA, and the Institute for Local Self-Reliance. The report shows how community solar is working for Minnesota, including for customers, workers, and landowners (2019).
- **Beyond Sharing**: a report exploring the opportunity of community renewable energy to enable energy democracy. It examines the benefits and barriers, barrier-busting policies, powerful examples, and how cities and cooperatives can lead the way (2016).
- **Minnesota's Value of Solar**: a report on Minnesota's landmark "value of solar" policy, adopted for community solar installations (2014).
- **Customers Pay when Big Utilities Make Big Errors in Electricity Forecasts**: an investigation of electric utility forecasts finds that utilities over-predict electricity demand to get permission to build more power plants (2019).

See also:

- **Minnesota's Smarter Grid**: a McKnight Foundation report on Minnesota's pathways to a "clean, reliable, and affordable transportation and energy system" (2018).

Executive Summary

Many U.S. utilities develop comprehensive resource plans every few years, often required by state law or state regulatory commissions. Especially in states where utilities have monopoly service territories, these plans set expectations for electricity use and the grid infrastructure required to meet it. However, these plans often drastically underestimate the contribution of electric customers and non-utility developers to the electricity system's resources – specifically the contribution of distributed solar. Utility regulators often defer to the utility and blindly accept utility forecasts, despite significant evidence that the forecasts are faulty, to the financial and economic harm of electric customers.

Undercounting distributed solar has significant financial and economic consequences. As shown in the **Smarter Grid** and other studies of the value of distributed energy resources, distributed solar can provide cost-competitive carbon-free electricity and significant economic and wealth-building benefits to a broad array of electric customers.

This report explores the phenomenon of undercounting customer-sited and non-utility solar energy in Minnesota: a state with several adopted policies expressing a public interest in distributed generation. It explores this phenomenon with a utility that has a strong reputation for pursuing low-carbon resources that it controls, Xcel Energy. The report finds that Xcel Energy's forecasts for distributed solar, including customer-sited and community solar, are significantly low in light of existing trends and comparative models. Accordingly, as in all states with monopoly regulated businesses, utility regulators must exercise vigilance to ensure that utility-scale and utility-owned investments don't crowd out distributed energy solutions just because they do not provide profits to the monopoly utility's shareholders.

Underwhelming Solar Forecasts

- ILSR compared Xcel Energy's rooftop solar forecasts to two independent models and found that rooftop solar growth is likely to be double, or more, than what the utility anticipates.
- ILSR compared Xcel Energy's community solar forecasts to the existing queue, recent growth trends, and system constraints and found that – barring legislative action to curtail it – community solar is likely to far outstrip the utility's projections.
- ILSR noted the lack of any forecast for wholesale distributed generation, despite several state-sponsored studies showing its economic superiority to transmission-connected resources. We also found that Minnesota's lack of compliance with federal competition law seriously undercuts the opportunity for this market to develop.

Introduction

In the past 100 years, the technology of electricity generation has come full circle—from small to big to small again. Power plants grew from a size sufficient to power a single city block in the early 1900s to giants by the 1950s, large enough to serve hundreds of thousands of customers. The process reversed in the 1990s with renewable energy. The first wind turbines powered several dozen homes, and two dozen solar panels could power just one home. As their cost has fallen dramatically, these smaller clean power sources can compete with large-scale power generation. If properly included in plans for the future grid, they can also play an important role in distributing the financial and economic benefits of power generation, a $360 billion per year industry in the U.S.

Unfortunately, while the scale of power generation has come full circle, utility planning missed a turn. Utilities have expanded their planning capabilities in response to state requirements and changing electricity demand, but they haven't adapted to the widespread availability of small-scale power generation. Often utilities look past distributed energy resources because their investors don't profit in the same manner as they do with building large things, but just as often it is due to deeply ingrained bad habits. This oversight can be costly for customers. Distributed energy resources, like rooftop solar, can provide uniquely affordable energy and grid services that larger scale systems, often connected to consumers by long-distance transmission, cannot.

This report illustrates utility blind spots toward distributed energy through the lens of an "integrated resource plan" of one of the country's largest utilities, Xcel Energy, for its Minnesota customers. As shown in the following analysis, the 15-year plan for the electric customers offers a very low forecast for distributed energy adoption.

While the analysis focuses on a single utility's plan, the implications apply to any utility's forecast of energy supply and demand. At best, relying on low forecasts of distributed energy will leave the utility unprepared for a significant deployment of rooftop solar and its grid impact. At worst, it could result in customers having to cover the cost of significant investments in unneeded power generation and affect the financial viability of the utility itself.

Rooftop Solar

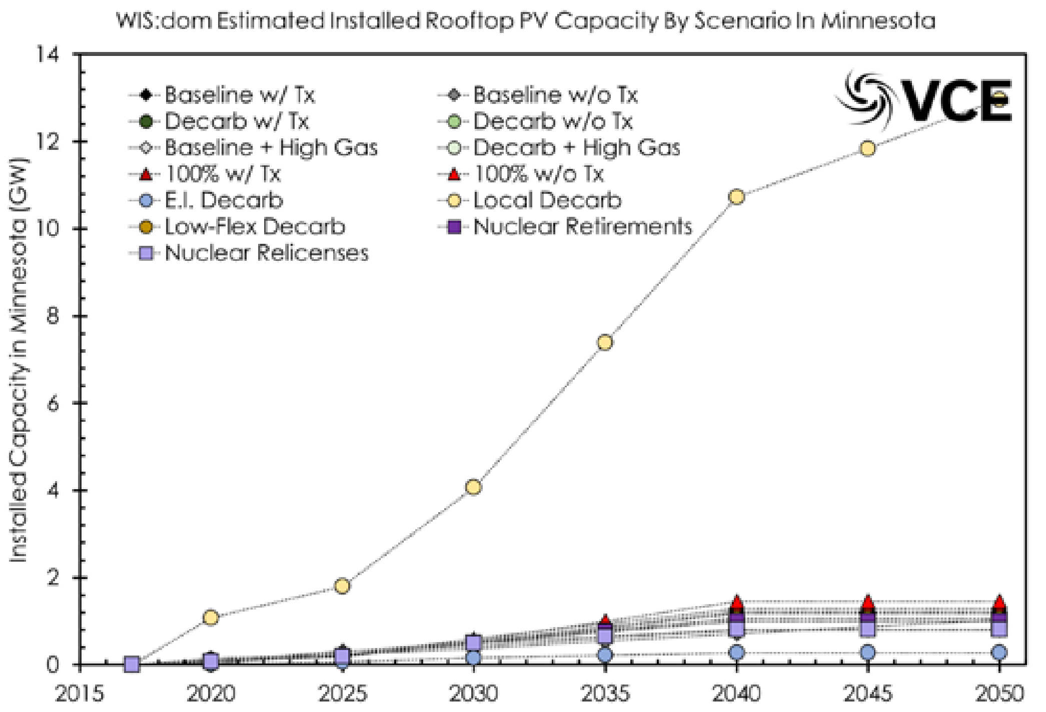
Customer solar adoption in Minnesota and many other states has grown rapidly in recent years, boosted by falling installation costs and state incentives. In Minnesota and a handful of states, solar adoption is also boosted by the availability of community solar programs. The following section illustrates the financial and economic benefits at stake in different grid futures, and then examines the distributed solar forecasts of Xcel Energy's Minnesota subsidiary compared to two different solar adoption models.

A Model of High Penetration and Widespread Benefits

Published last year, Minnesota's Smarter Grid **study** shows that widespread distributed solar adoption is feasible and economically rewarding. In a state that's nearing 1 gigawatt of installed distributed energy resources, the study showed that a thirteen-fold increase in solar by 2050—including approximately 5 gigawatts by the mid-2030s—results in similar financial savings for all customers as statewide low-carbon electricity grid ("decarbonization") scenarios that focus solely on utility-scale solar. The local solar scenario creates over 40,000 jobs and would provide billions of dollars in customer energy bill savings.

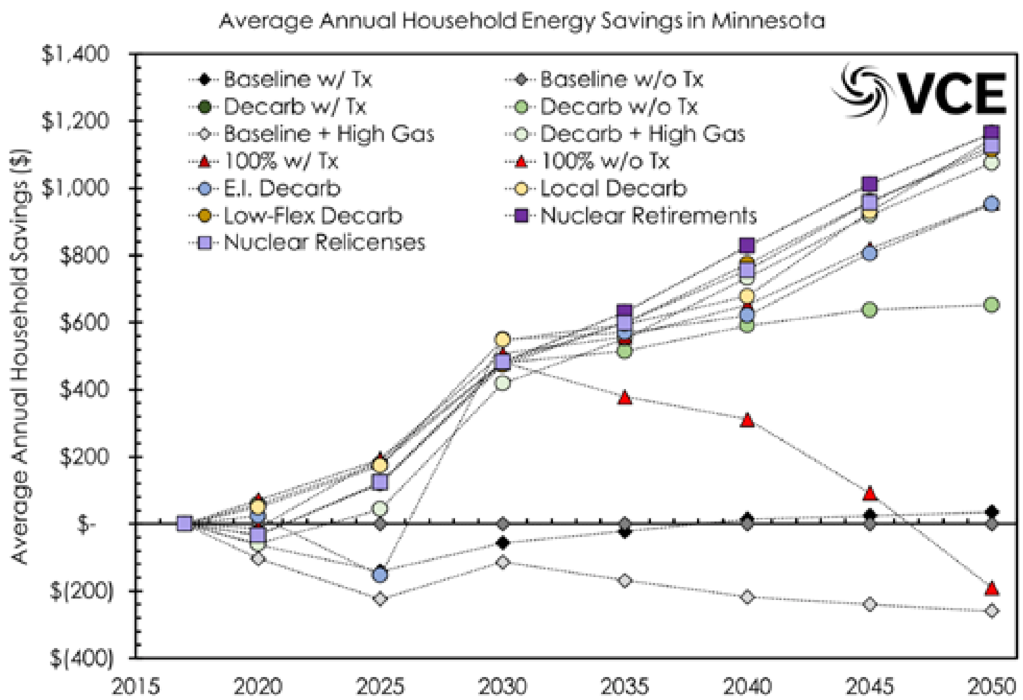
The following charts illustrate the opportunity. The first shows the quantity of installed rooftop solar in Minnesota through 2050 in the Vibrant Clean Energy Smarter Grid model.

The Smarter Grid Study 13-Gigawatt Rooftop Solar Local Decarbonization Scenario



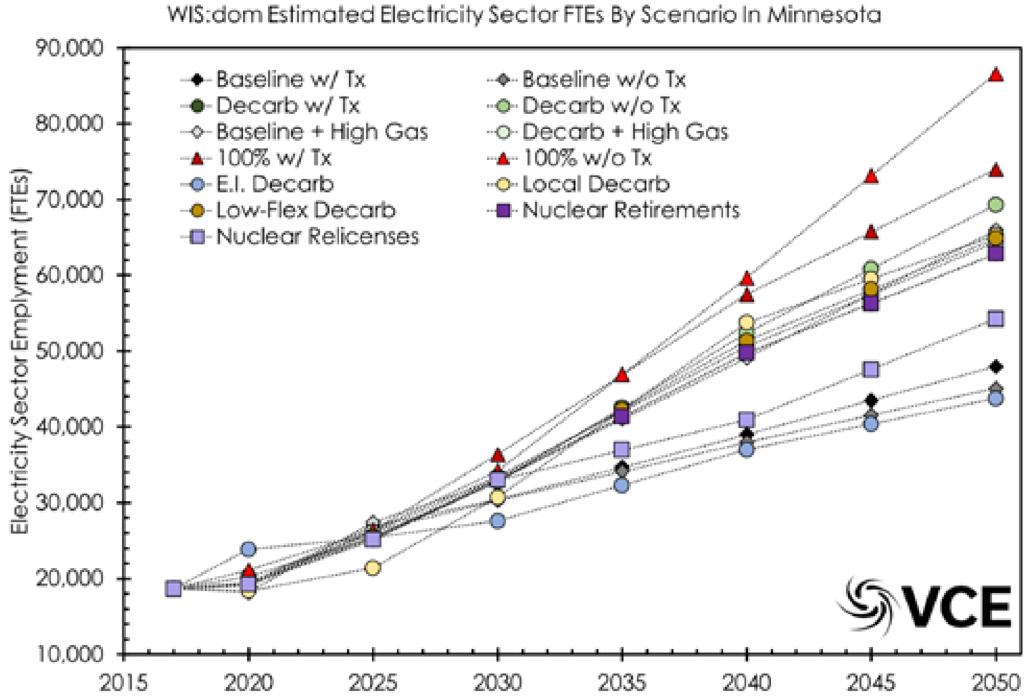
The second chart compares household energy savings for different decarbonization scenarios. The Local Decarbonization scenario, featuring 13 gigawatts of rooftop solar installed by 2050, provides close to the highest financial benefit. The dot representing the scenario, in yellow, is hidden just below the purple square of the Nuclear Retirements scenario, which showed the highest annual average savings for Minnesota households.

The Smarter Grid Study 13-Gigawatt Rooftop Solar Scenario Creates High Savings



The final chart illustrates the job creation benefits of the differing scenarios, showing that the rooftop solar maximization scenario creates 40,000 jobs, more than any other scenario with comparably high levels of household energy savings.

The Smarter Grid Study 13-Gigawatt Rooftop Solar Scenario Creates 40,000+ Jobs



Utilities often ignore "local decarbonization" or rooftop solar scenarios in planning because they do not directly control deployment of these resources. Investor-owned utilities, in particular, may be reluctant to show state regulators scenarios that reduce the utility's need to spend capital, its most reliable route to earning a profit.

Given the superior financial and economic benefits to utility customers of a high rooftop solar adoption scenario, electric utilities in Minnesota and elsewhere should be required to model aggressive rooftop solar and distributed energy adoption scenarios and include these models, assumptions, and underlying calculations in resource plan forecasts.

One Minnesota Utility's Rooftop Solar Modeling

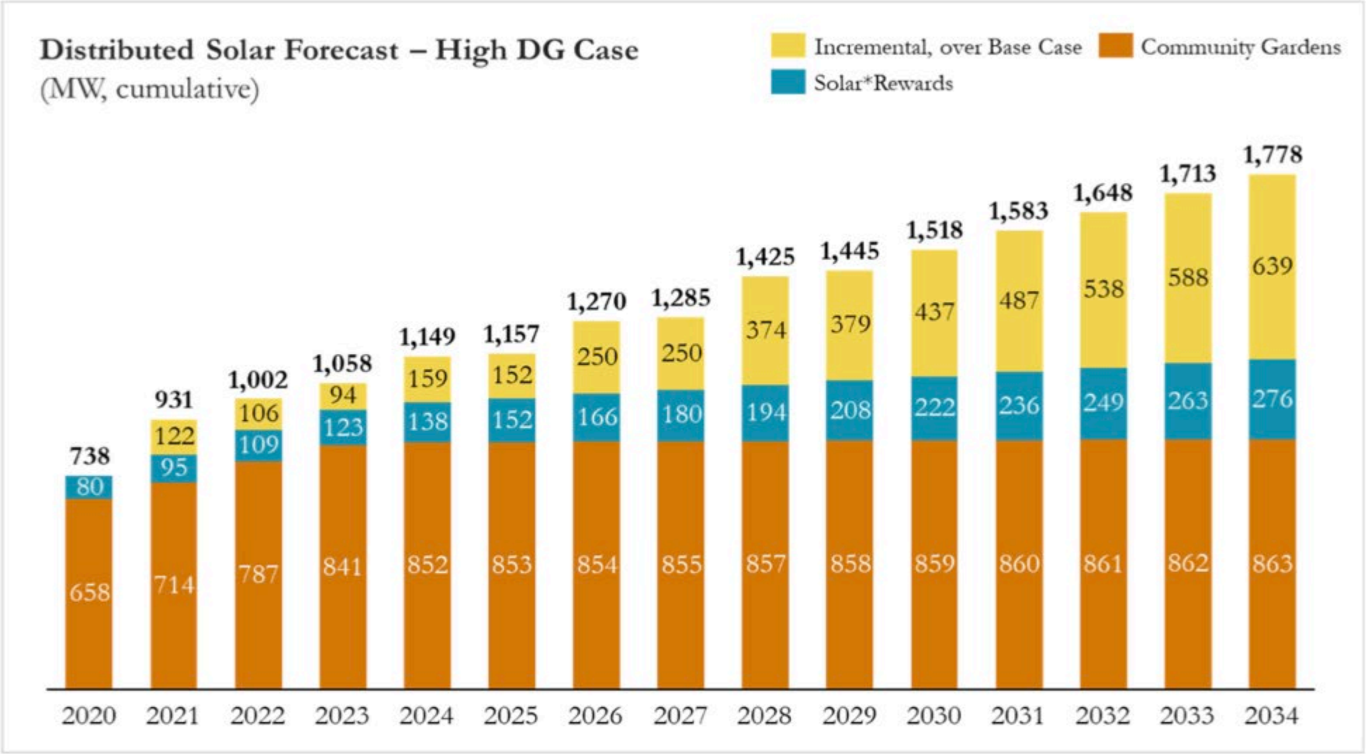
In its recently filed resource plan, Xcel Energy's rooftop solar forecast comes in low.[1] Its base case assumes roughly 275 megawatts of new rooftop solar by 2034, with no increase in the pace of adoption. The utility's High Distributed Solar (or High DG for "distributed generation") scenario adds 640 megawatts, but doesn't distinguish between customer-sited rooftop solar and community solar, as the utility views them as interchangeable for customers despite significant differences in payback.

The following is excerpted from the resource plan filing, explaining the "High DG" scenario:

> "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...This growth is not differentiated by program, as net metering and [community solar gardens] 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."

The chart below is taken from the resource plan filing. Solar*Rewards and net metering projects are shown in blue, representing rooftop solar. Community gardens (orange) are community solar. The High DG Scenario (yellow) mixes rooftop solar and community solar.

Figure III-2: High Distributed Solar Adoption Scenario Forecast



1. SUPPLEMENT 2020-2034 Upper Midwest Integrated Resource Plan (Docket No. E002/RP-19-368). https://bit.ly/3gu-wYUX

A Comparison of Utility Modeling to Others

In this section, we compare two alternative models for distributed solar to the Xcel Energy 2034 forecast. The National Renewable Energy Laboratory recently published a distributed solar projection for Kentucky using a new model called dGen.[2] While this tool is not publicly available yet, it is possible to adjust the analysis for another state based on known differences in adoption, total potential, and electricity rates. The Institute for Local Self-Reliance (ILSR) did such an analysis.

In particular, ILSR's adjustment to the published Kentucky model made these changes:

- Increasing the forecast to account for the higher solar rooftop potential, as modeled by the National Renewable Energy Laboratory
- Increasing the forecast by including existing distributed solar projects in Minnesota
- Decreasing the forecast by 25% to account for Xcel Energy's share of statewide electricity customers and existing distributed solar installations

Adjusting the national lab's Kentucky solar adoption model for Minnesota shows that potential installations of distributed solar in Minnesota are likely much higher than modeled in the Xcel resource plan. The adapted mid-range analysis suggests distributed (rooftop) solar adoption of approximately 980 megawatts statewide by 2034. Given that Xcel Energy hosts 83 percent of distributed solar projects in Minnesota (and over 90 percent if community solar is included),[3] the comparative figure would be a projection of approximately 736 megawatts of rooftop solar PV (megawatts AC) in Xcel's Minnesota territory by 2034. (*See Appendix for more detail*).

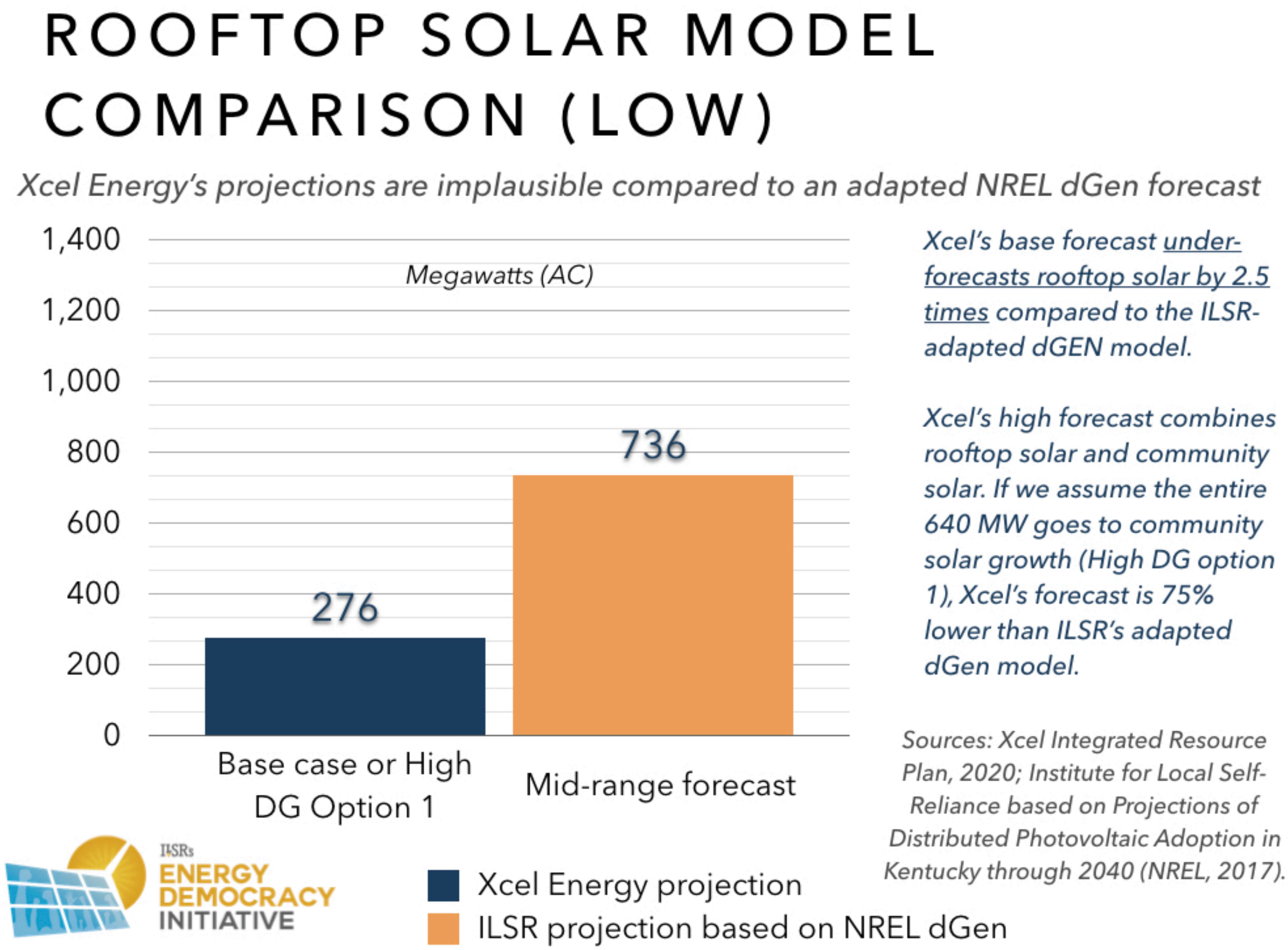
This estimate is conservative, for two major reasons:

- Electricity prices in Minnesota are 9 percent higher than Kentucky, improving the payback for customers[4]
- While we did account for Minnesota's higher base of installed projects in the year 1 forecast, we did not account for market maturity. In other words, we can expect distributed solar to grow more quickly in Minnesota than Kentucky because the level of market maturity means more customer exposure to solar opportunities (e.g. **solar is contagious**)

In comparison to the ILSR-adapted Kentucky solar projection model, Xcel's projections rest on implausible assumptions. In their High DG scenario, Xcel lumped together rooftop and community solar. ILSR compared the two extremes of this High DG forecast: High DG Option 1 (counting all 640 megawatts of Xcel's High DG forecast toward community solar) and High DG Option 2 (counting all of Xcel's High DG forecast toward rooftop solar). At either extreme (either all 640 megawatts are installed as rooftop solar or community solar), Xcel Energy's High DG model underestimates both rooftop and community solar (more on the latter later).

2. Gagnon, Pieter and Paritosh Das. Projections of Distributed Photovoltaic Adoption in Kentucky through 2040. (National Renewable Energy Laboratory, June 2017). https://bit.ly/3dGL7gI.
3. Distributed Energy Resources Data. (Minnesota Public Utilities Commission). https://mn.gov/puc/energy/distributed-energy/data/
4. 2017 Utility Bundled Retail Sales- Residential. (Electric Power Monthly, Energy Information Administration). https://www.eia.gov/electricity/data.php#sales

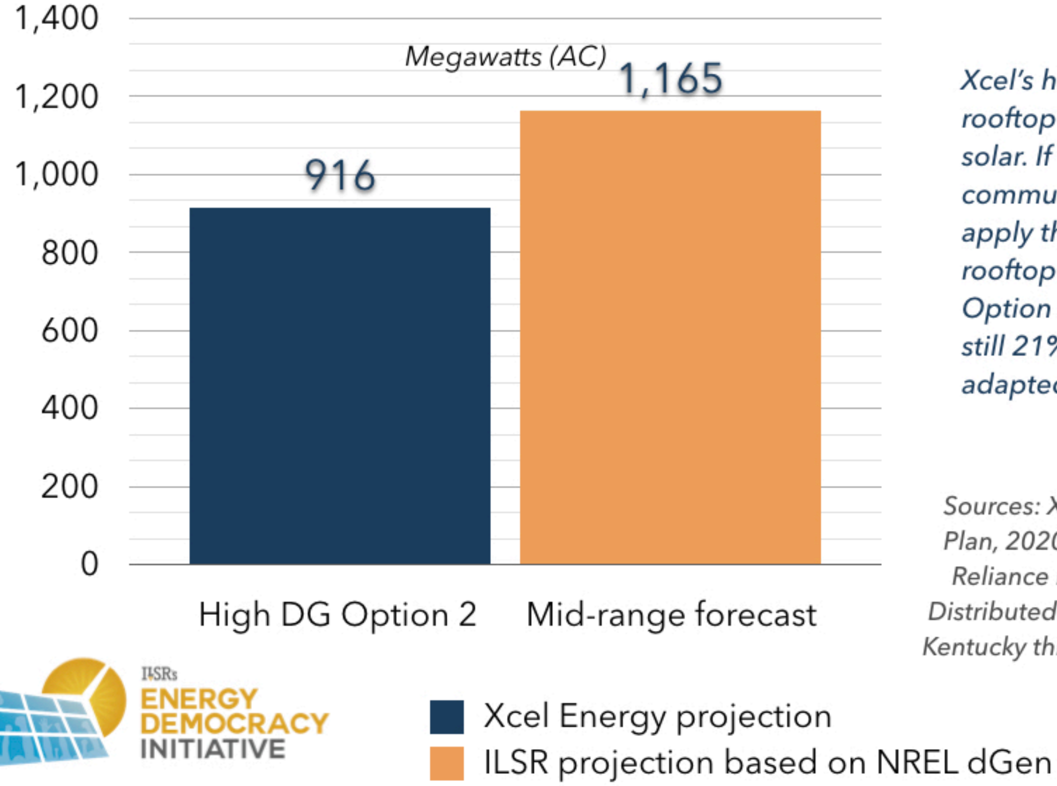
The following chart illustrates how Xcel Energy's Base Case and High DG Option 1 (all community solar) forecasts 75 percent less rooftop solar than ILSR's adapted dGen model.



If all of the 640 megawatts in the High DG model are rooftop solar installations (High DG Option 2), then Xcel's community solar forecast will essentially expect the community solar program to cease operations after 2019. Even with this highly implausible assumption, the following chart shows that Xcel Energy's forecast *still* potentially undercounts distributed solar installations by 21 percent compared to ILSR's adaptation of the NREL dGen model.

ROOFTOP SOLAR MODEL COMPARISON (HIGH)

Xcel Energy's projections are implausible compared to an adapted NREL dGen forecast



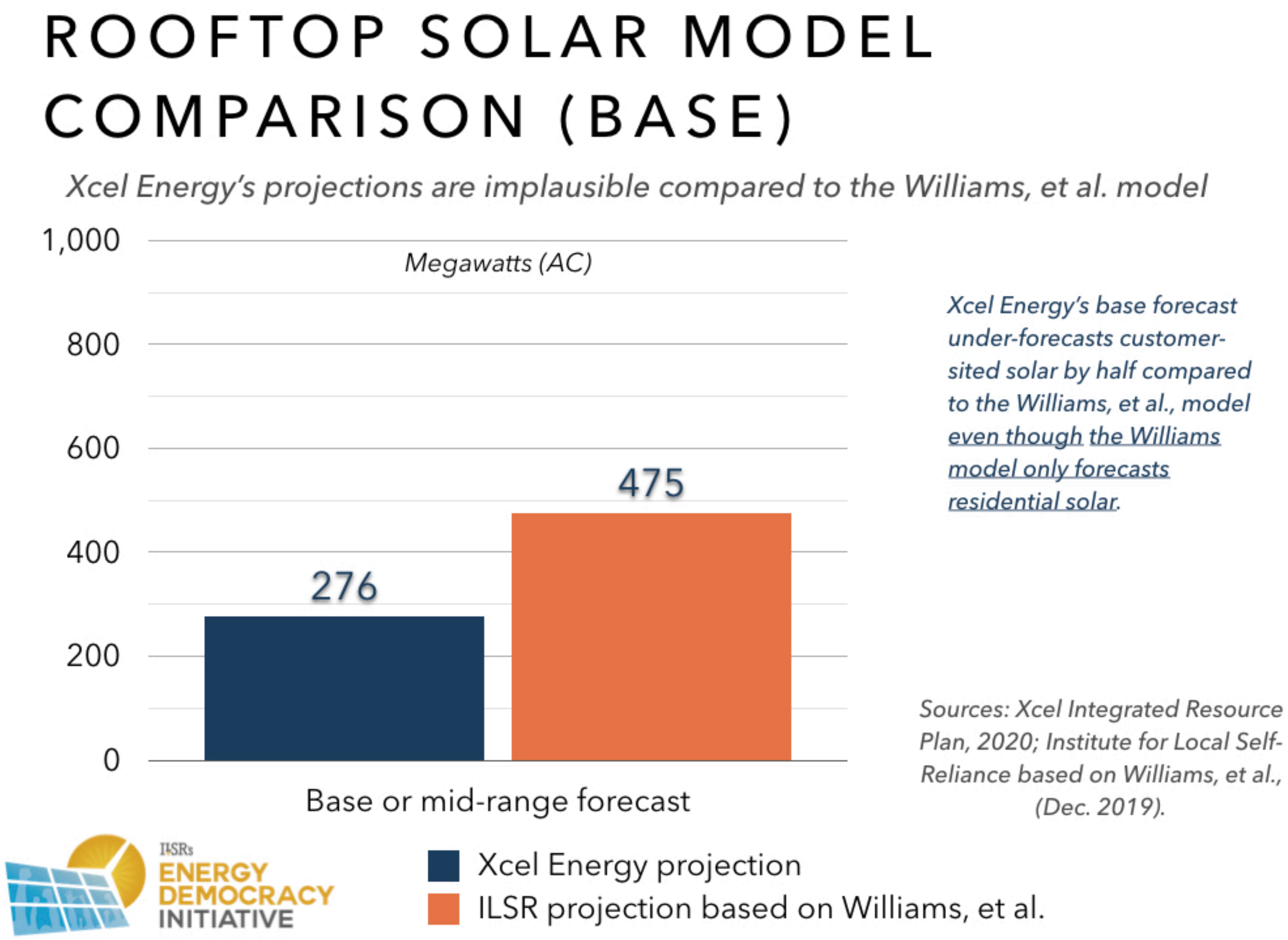
Xcel's high forecast combines rooftop solar and community solar. If we assume near-zero community solar growth and apply the entire 640 MW to rooftop solar (High DG Option 2), Xcel's forecast is still 21% lower than ILSR's adapted dGen model

Sources: Xcel Integrated Resource Plan, 2020; Institute for Local Self-Reliance based on Projections of Distributed Photovoltaic Adoption in Kentucky through 2040 (NREL, 2017).

ILSR's ENERGY DEMOCRACY INITIATIVE

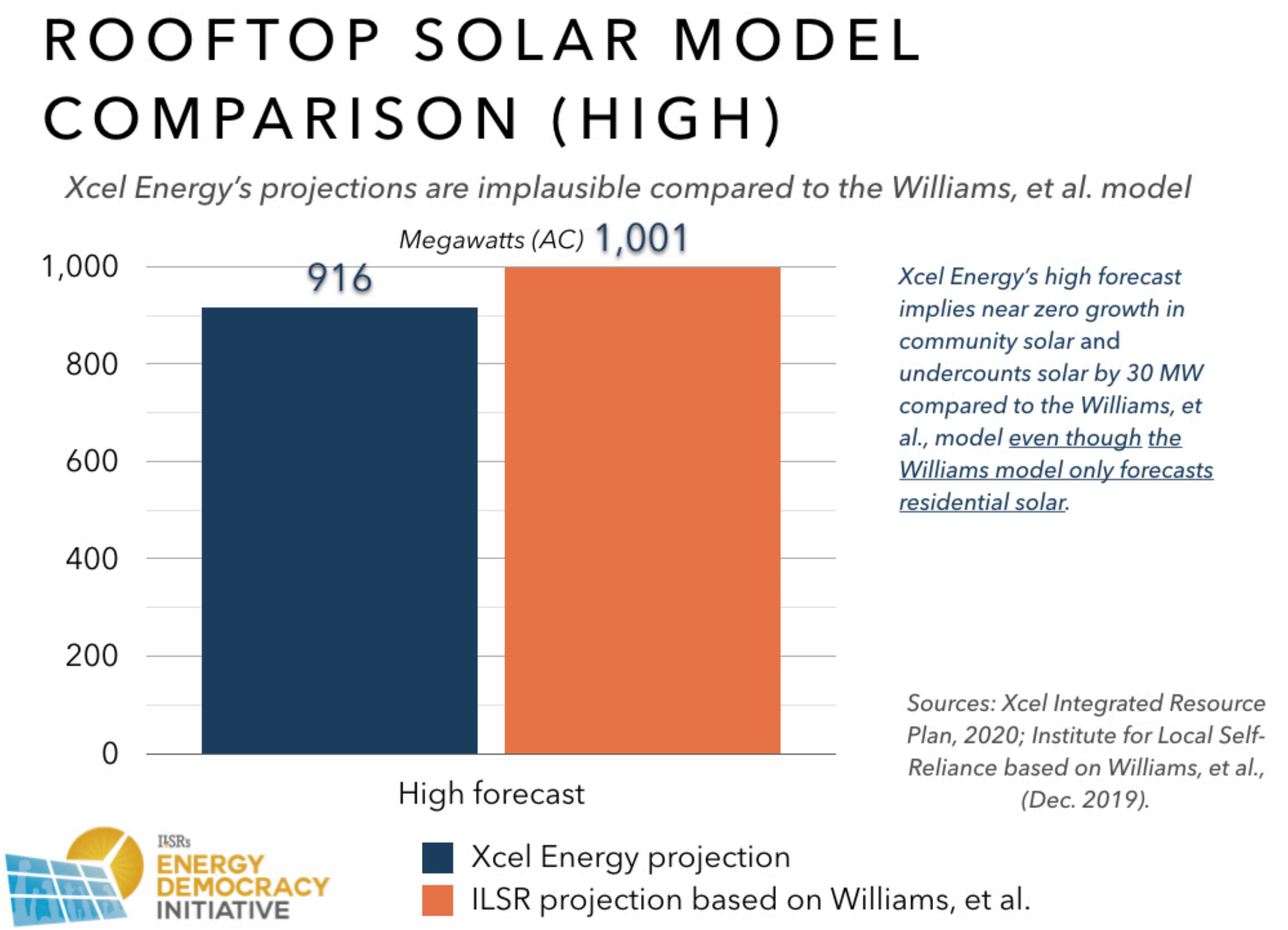
The National Renewable Energy Laboratory dGen model isn't the only one to show the shortcomings of Xcel Energy's distributed solar forecasts. Published in December 2019, a paper in *Renewable Energy* published by Eric Williams, et al., builds a model for residential solar PV adoption based on the net present value for customers. The model fits well with actual solar deployment in international (Germany, Japan) and domestic markets (California, Massachusetts, and Arizona). According to an analysis conducted by the Institute for Local Self-Reliance (and reviewed by the paper's authors), Xcel Energy's distributed solar forecasts fall short of projected market deployment based on the economic decisions residential customers are likely to make given the future costs of solar. In fact, **Xcel Energy's forecast for all customer-sited solar (residential and commercial) is less than the Williams model that forecasts <u>residential solar only</u>.**

The Williams, et al., base model assumes a 5% annual decrease in the cost of rooftop solar (the 5-year annual average), that the federal Investment Tax Credit expires as scheduled, and includes the Solar*Rewards program with the currently expected sunset after 2021.[5] Even with this relatively conservative projection of residential projects only, Xcel's base forecast that includes all forms of behind-the-meter solar falls short by nearly half. (*See more detail in the Appendix*).



5. Made in Minnesota Solar Incentive Program. (Minnesota Department of Commerce). https://mn.gov/commerce/industries/energy/solar/mim/

The High DG forecast from Xcel Energy similarly compares poorly to ILSR's High Forecast built on the Williams model. In this case, ILSR adjusted the model to assume a 10% annual decrease in the cost of rooftop solar that the federal Investment Tax Credit expires as scheduled, and that the Solar*Rewards program is extended but decreases in value by 0.5¢ per kilowatt-hour each year (*more detail in the Appendix*). Compared to the ILSR's Williams model residential-only High Forecast, Xcel's all-project-type forecast still undercounts distributed solar by 85 megawatts despite nearly zeroing out the projected growth in community solar.



The two forecasts demonstrate that Xcel Energy's distributed solar forecasts are too low, and may result in planning for resource acquisitions that will not be able to recover costs.

Recommendation

Due to its significant shortcomings compared to other rooftop solar deployment models, Xcel Energy's resource plan forecast should at least double its projections for rooftop distributed solar adoption over the planning period.

In general, all utilities should demonstrate that their distributed solar forecasts have merit by transparently sharing their assumptions and modeling methods. Preferably, these models would be benchmarked against or themselves be open sourced models for distributed solar deployment.

Community Solar and Community Renewable Energy

Numerous states now offer community solar programs, allowing customers access to solar energy without having to own a sunny rooftop. For most states, forecasting community solar growth is easy, because programs have been designed with annual capacity caps. Minnesota's community solar program serving Xcel Energy customers has no cap, to avoid competition between residential and commercial participants. However, it makes growth forecasts more challenging.

A History of Coming Up Short

In its resource plan, Xcel Energy provides a community solar growth forecast. Even before viewing the actual numbers, some skepticism is warranted. In more than one case, Xcel has a history of under-forecasting community solar. Shortly after the program became law in 2013, Xcel proposed allowing just 20 megawatts of development over the first two years.[6] In November 2018, Xcel provided a forecast of community solar growth in its bid to purchase a gas plant in Mankato, Minn. In Attachment A of that filing—show to the right—the utility forecast the total capacity of community solar projects to reach 720 megawatts by January of 2030. At that time, however, the queue of projects in service or in the design/construction phases totaled 717 megawatts. In other words, according to Xcel's Nov. 2018 model, there would be virtually no additional community solar development between 2020 and 2030. (For the record, the program capacity reached 688 MW of capacity in May 2020, nearly six years ahead of Xcel's 2019 forecast).[7]

Table 13: Distributed Solar Forecast

Distributed Solar (Nameplate MW)				
Year	Solar Rewards	Net Metered	Community Gardens	Total
2018	29	18	246	293
2019	41	27	504	573
2020	49	37	641	727
2021	53	47	649	749
2022	56	58	657	771
2023	57	70	665	792
2024	57	83	673	813
2025	56	96	681	834
2026	56	109	689	854
2027	56	122	697	875
2028	55	135	705	895
2029	55	147	713	915
2030	55	160	720	935
2031	55	172	728	955
2032	54	185	736	975
2033	54	197	744	995
2034	51	212	751	1,014

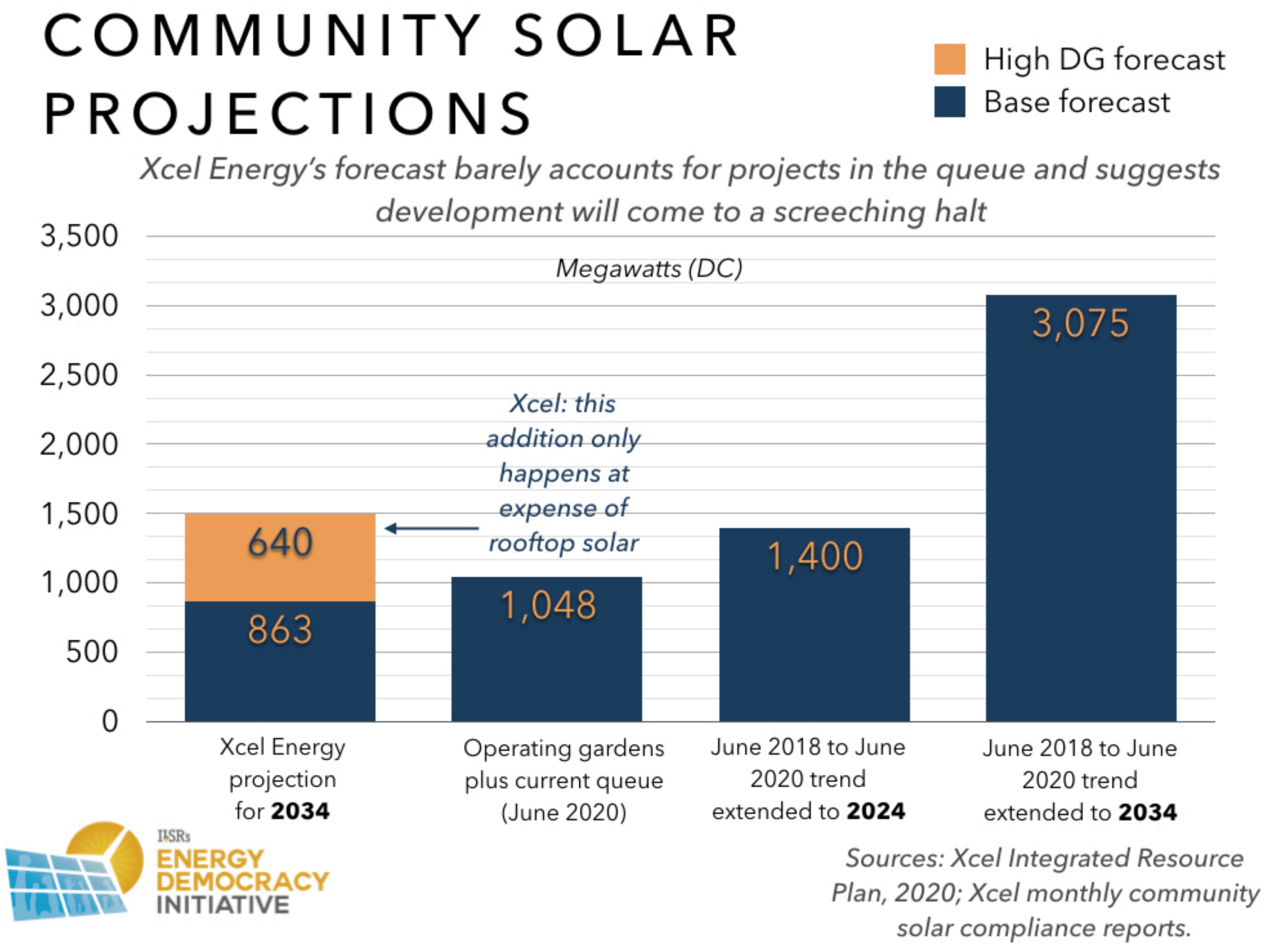
A Newer Model, A Continued Problem

To its credit, Xcel Energy's July 2019 resource plan filing improves upon the earlier forecast, but it still only shows an expectation of 786 megawatts by 2030, for total program growth of just 66 megawatts in ten years compared to 600 megawatts in five years from 2014 through 2019. The revised 2020 forecast is marginally better, with an expectation of 859 megawatts of community solar by 2030. However, the utility's current forecast assumes a community solar growth rate that is two-thirds lower than the historical average.

The growth trend for community solar has slowed somewhat, but even accounting for that, Xcel's forecast is far too low. In the past two years (June 2018 to June 2020), projects totaling 335 megawatts (MW) came online. At the same time, the total community solar project queue shrank by 85 MW. In other words, new projects have not entered the queue quite fast enough to replenish the pipeline. Should this continue, the project queue will empty by the end of 2024. However, if project development continues at the same two-year pace, by the end of 2024 the program would have nearly 1,400 MW of capacity, 60 percent more than Xcel's forecast (and nearly as much as the utility's High DG scenario if none of it happens as rooftop solar). And if the queue refills and just the existing growth trend continues, community solar could provide over 3,000 megawatts by 2034, twice as much Xcel's most ambitious forecast.

6. Shaffer, David. Xcel Energy opens way for solar gardens. (Star Tribune, 10/1/13). http://strib.mn/3732vd7
7. Farrell, John. Why Minnesota's Community Solar Program is the Best. (Institute for Local Self-Reliance, updated monthly). https://ilsr.org/minnesotas-community-solar-program/

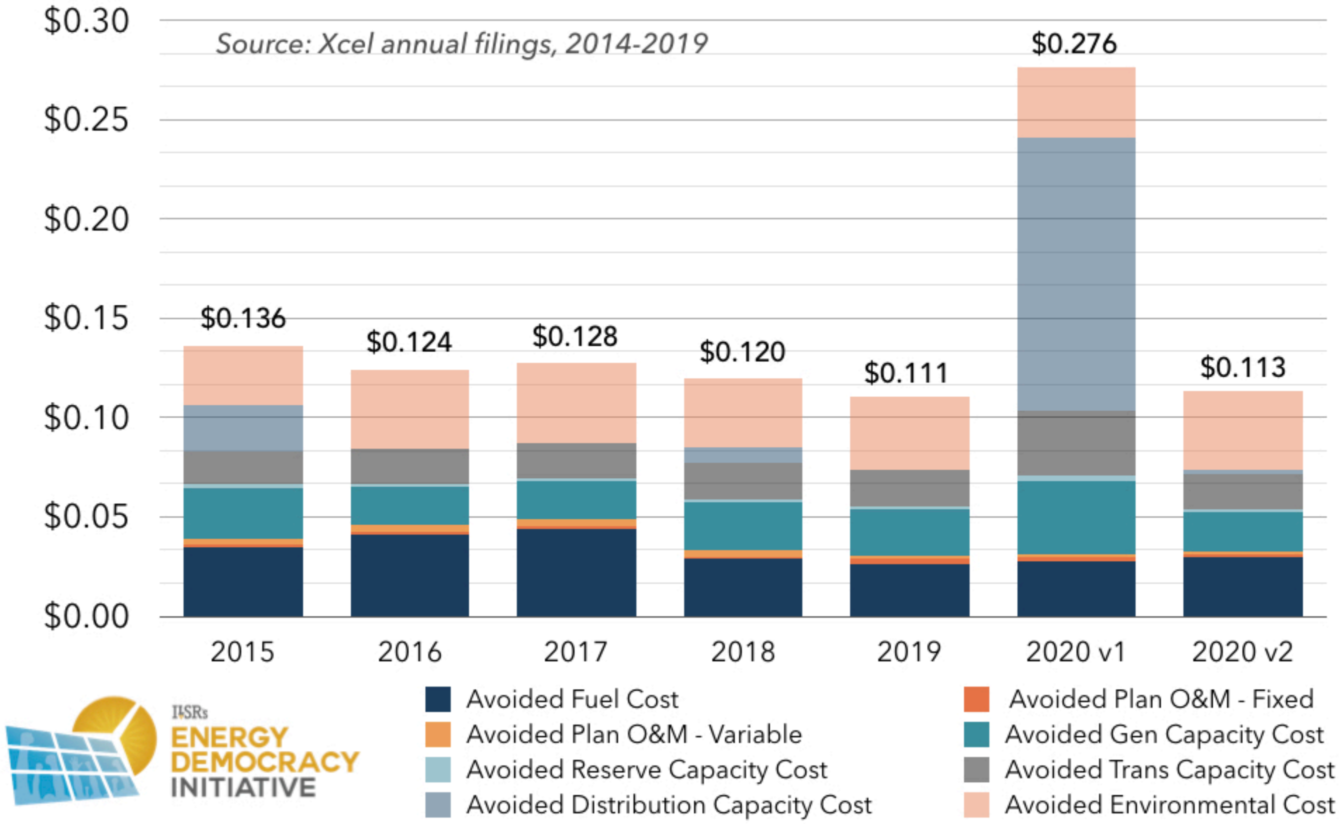
The following chart captures the gap between project activity and Xcel's projections. If new development abruptly stops and just the projects in the queue get built, Xcel will still under-estimate community solar growth by nearly 200 MW. If historical trends continue over the next five years, Xcel's base case forecast is low by nearly 50 percent and 10 years late. If historical trends continue until the end of the forecast period in 2034, Xcel's most ambitious forecast is still short by 50%.



Xcel Energy's low forecast may rely on the expectation that the value of solar, used to compensate community solar projects, will fall. The calculated value fell by 2.5 cents per kilowatt-hour from 2015 to 2019. It then rose by 0.2 cents per kilowatt-hour from 2019 to 2020, after a brief but exciting discussion about a price spike due to a poorly designed formula for calculating avoided distribution capacity. The following chart shows the trend in value of solar since its inception, with the original and amended 2020 rates.

XCEL VALUE OF SOLAR

Due to falling gas costs, the value of solar has trended down; for 2020, Xcel unilaterally changed the methodology for avoided distribution costs after a formula quirk doubled the total value of solar rate



The annual approval process has been rather contentious, given the implications for community solar development and the utility's history of trying to curtail the program (even while praising it). The 2020 approved value left unresolved several disputes over the avoided fuel cost (particularly whether gas is the appropriate fuel offset), the assumed annual production of community solar projects (actual versus modeled), and the power plant cost and maintenance data (currently pulled from a to-be-approved resource plan).

One thing is certain. Much of the value of solar decline from 2015 to 2019 was due to falling gas prices, which seem unlikely to fall much further. Thus, an extremely conservative community solar forecast relying on a declining value of solar may be in error.

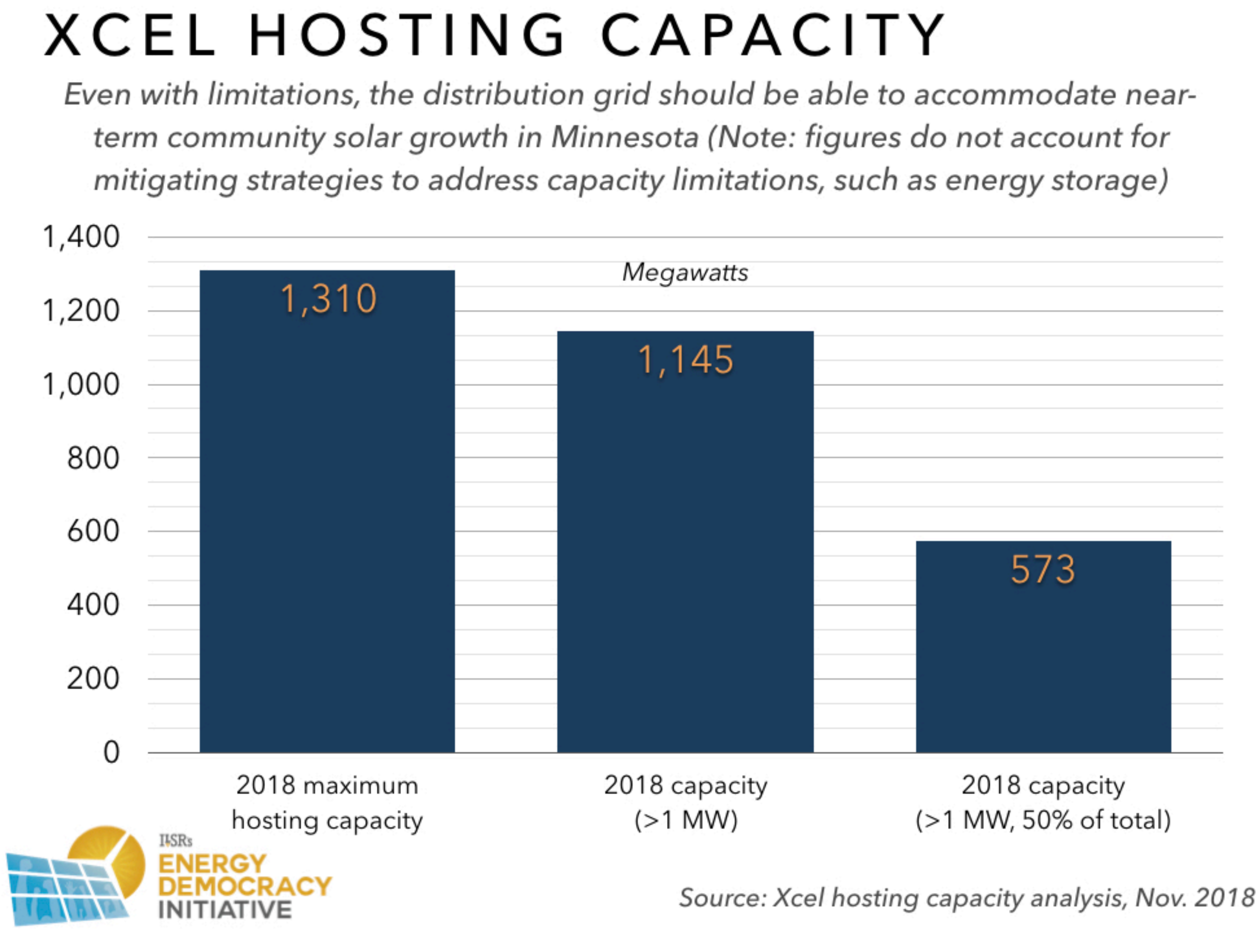
Can Community Solar Connect?

Available interconnection points for new community solar projects also impact future growth. In particular, more data is needed about available capacity on distribution feeders serving the Twin Cities metropolitan area.

Xcel Energy publishes an annual hosting capacity analysis to identify available system capacity at the distribution feeder level. While the 2017 and 2018 data are not directly comparable due to improvements in methodology, the data suggest that the available space on the utility's system for large distributed projects like community solar (1 megawatt each) is shrinking. Overall, the total of maximum hosting capacity of all feeders on Xcel's system fell from 6,300 megawatts to 1,300 megawatts from the 2017 to 2018 analysis. The capacity for projects is further constrained in three ways (but also mitigated in others).

For the first constraint, community solar projects tend to be 1 megawatt, so feeders with less than 1 megawatt of capacity aren't likely to be sufficient. That lowers the maximum capacity from 1,300 to 1,145 megawatts. Second, the sum of available capacity on individual feeder lines could exceed the capacity of the substation. For example, the Afton substation (selected as the first alphabetically) serves four feeders with maximum hosting capacity of 0.48, 1.77, 2.14, and 3.49 megawatts, respectively. While the total capacity of the three with at least 1 megawatt each is 7.4 megawatts, the Afton substation may only be able to handle, for example, 2.5 megawatts of new generation. To be conservative, we illustrate a scenario below assuming that each substation can handle half of the cumulative hosting capacity of its feeders. Finally, to serve customers in the Twin Cities metro area, the project has to be located in an adjacent county to one of the urban counties. Some substations are too far afield (that being said, the urban substations tend to have the higher hosting capacities--feeders connected to the Wilson substation in Bloomington, a Minneapolis suburb, have a maximum hosting capacity of 37 megawatts).

The following chart illustrates the hosting capacity figures, taking into account the limitations addressed above. However, the chart does not include any mitigation strategies. For example, the utility hosting capacity report does not consider strategies including inverter loading ratios or energy storage, both of which can meaningfully increase hosting capacity or alleviate modeled limitations.



In the near term, Xcel's hosting capacity seems sufficient to accommodate the current growth trend of community solar projects through 2024. As noted above, the analysis also leaves out an important and likely future development—the inclusion of energy storage. In its 2018 filing, Xcel explained that storage could expand the grid's capacity for more distributed energy like community solar:[8]

"Battery storage has the potential to act as a load to reduce thermal and voltage impacts, effectively increasing the hosting capacity if properly sited and coordinated with DER output."

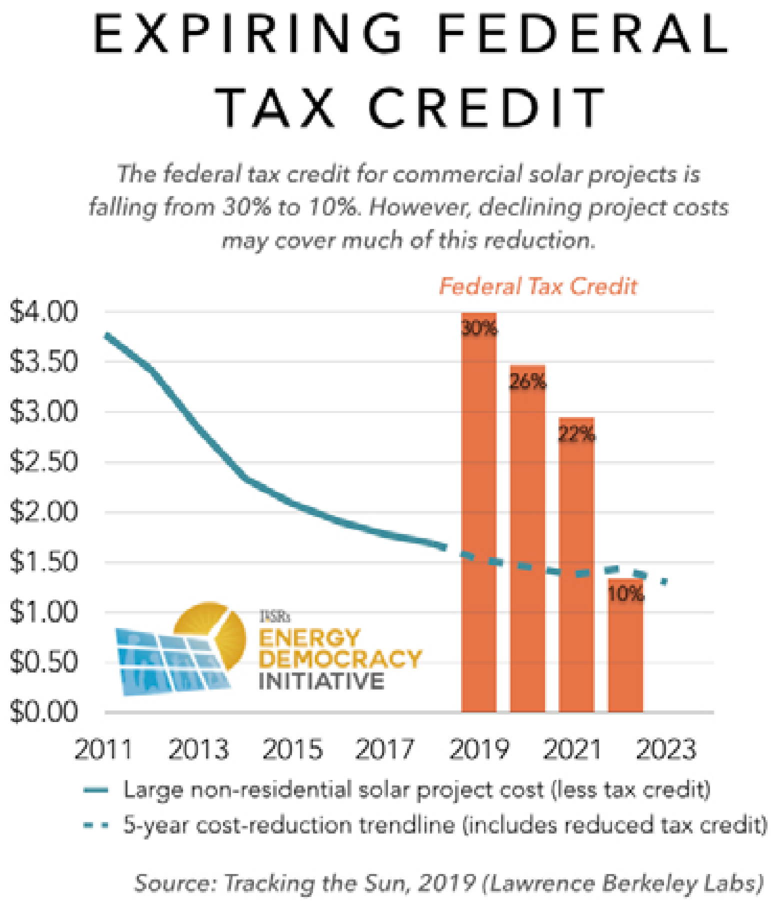
Overall, Xcel Energy's forecast for community solar assumes a dramatic drop in the rate of growth that doesn't match changing market conditions or available capacity on its system.

8. Hosting Capacity Report, (Xcel Energy, 11/1/2018), Docket No. 17-777.

The Tax Credit Impact

The expiration of the federal solar tax credit, or reduction from 30% to 10% for commercial projects like community solar, will impact community solar project development. However, given the trend of cost decreases for large, non-residential solar projects nationwide, the impact may be smaller than at first glance. According to Lawrence Berkeley Labs, large, non-residential solar installed costs have been falling by 10 percent per year over the past 5- and 10-year periods.[9] The following chart extends the five-year cost decline out a further five years, adding in the impact of the reduced tax credit.

Although the tax credit will fall from 30% to 10%, anticipated price declines for community solar projects mean that total project costs are likely to keep declining, if at a slower pace. In other words, it does not appear that the reduced tax credit will significantly impact community solar deployment, all else being equal.



Recommendation

The Xcel Energy resource plan—like any utility forecast of community solar—should reflect likely growth in community solar by accounting for queued capacity, available grid capacity, and the relatively small impact of the Investment Tax Credit sunset. A likely outcome would be to double forecast capacity for community solar.

In addition to fairly evaluating physical limitations, all utility forecasts should separately account for community solar and distributed solar growth, given their very different profiles, means of compensation, and constraints.

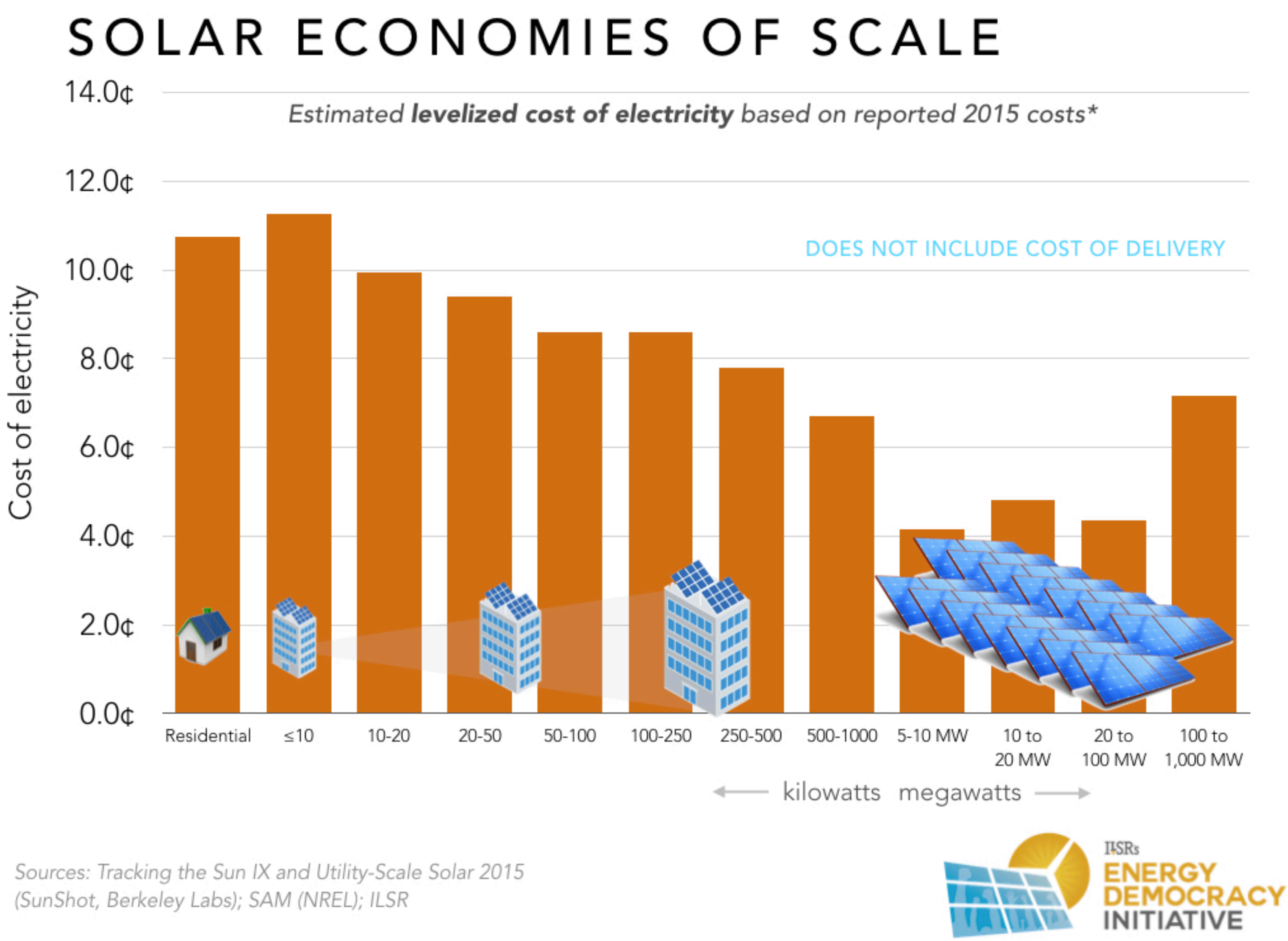
9. Barbose, Galen and Naîm Dargouth. Tracking the Sun, 2019 Edition. (Berkeley Lab, October 2019). https://bit.ly/3gVi9f3

A Missing Piece: Wholesale Distributed Generation

With the shortcomings of net-metered and community solar forecasts, regulators may also want to consider how wholesale distributed generation could provide new capacity with low infrastructure costs and impact utility resource plans.

Beginning in 1978, the federal government opened wholesale electricity markets to competition when it passed the Public Utility Regulatory Policies Act (PURPA). Stung by cost overruns at large-scale power plants, the law created a path for smaller scale generation to enter the market, requiring utilities to buy it, if it was cost-effective. Over the past four decades, thousands of megawatts of cost-effective electricity, often renewable, have been developed in states that have properly implemented the federal law.

Unfortunately, many states have let their PURPA compliance lapse, closing off this important market segment. It's particularly important for solar, because the sweet spot for cost-effective solar projects falls squarely in the size of projects PURPA was designed to encourage (less than 80 megawatts in non-competitive markets, less than 20 megawatts in competitive markets). The following chart, from ILSR's report **Is Bigger Best in Renewable Energy?**, illustrates the benefit of encouraging solar at this scale.



Unlike most states, Minnesota has a history of trying to encourage distributed generation. Lawmakers designed several laws and programs to encourage distributed renewable energy and chartered research studies to illustrate the capacity of the existing transmission system to accept new, distributed renewable energy projects. However, despite the state's expressed interest and the potential for it to provide cost-effective electricity to Minnesota customers, few wholesale distributed projects have come to fruition and utility forecasts suggest little expected development in the future.

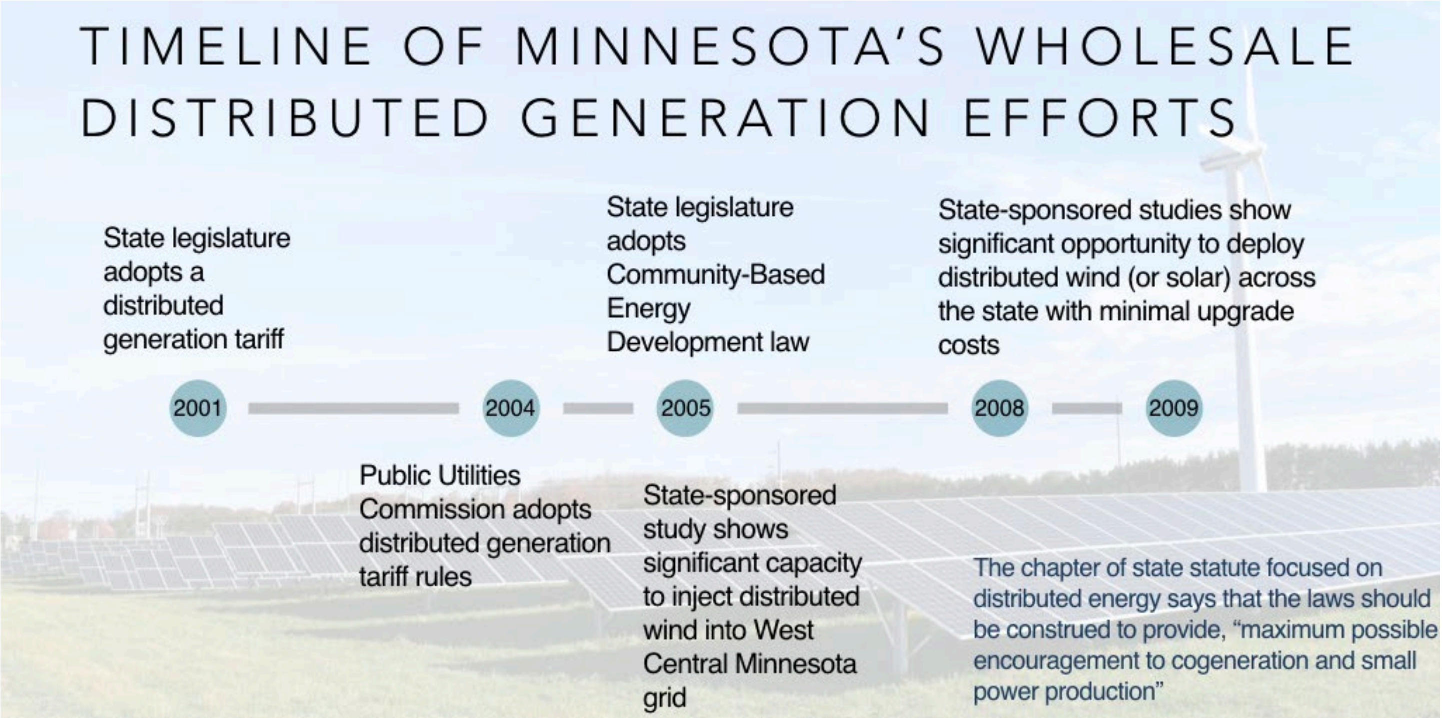
State Efforts to Support Wholesale Distributed Generation

In 2001, Minnesota adopted a distributed generation tariff intended to encourage wholesale distributed generation projects 10 megawatts and smaller (the Public Utilities Commission adopted rules in 2004).[10] Unfortunately, the tariff has led to no project development.[11]

Subsequently, in 2005, a state-sponsored study identified enormous available capacity on the lower-voltage transmission system to inject electricity from dispersed wind energy projects. Additionally, that year the state adopted the community-based energy development law, creating a tariff to support wholesale distributed generation from community-based projects by front-loading contract compensation.[12] Further state grid studies published in 2008 and 2009 reinforced the idea that new, distributed renewable energy capacity could be added without expanding the transmission network.

In addition to specific tariffs and studies, the chapter of state statute focused on distributed energy says that the laws should be construed to provide, "maximum possible encouragement to cogeneration and small power production."[13]

10. In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Laws 2001, Chapter 212. (PUC order, Docket 01-1023, 9/28/04). http://bit.ly/33eLjzr
11. Motion of the Minnesota Solar Energy Industries Association, et al. (Docket 01-1023, 3/23/18). http://bit.ly/3d1CIon
12. Community-Based Energy Development (C-BED). (Institute for Local Self-Reliance). https://ilsr.org/rule/community-based-energy-development-c-bed/
13. Petition for Reconsideration by the Environmental Law & Policy Center and Institute for Local Self Reliance. (Docket 19-9, 3/12/20). http://bit.ly/2QcHq8R



These state efforts are supplemented by the federal law called PURPA, which requires utilities to buy electricity from wholesale renewable energy generators at their "avoided cost." Once again, however, Minnesota's implementation has not matched its legislative intent, with significant barriers to distributed wholesale generation due to poor implementation.

A Study Shows Significant Available Grid Capacity

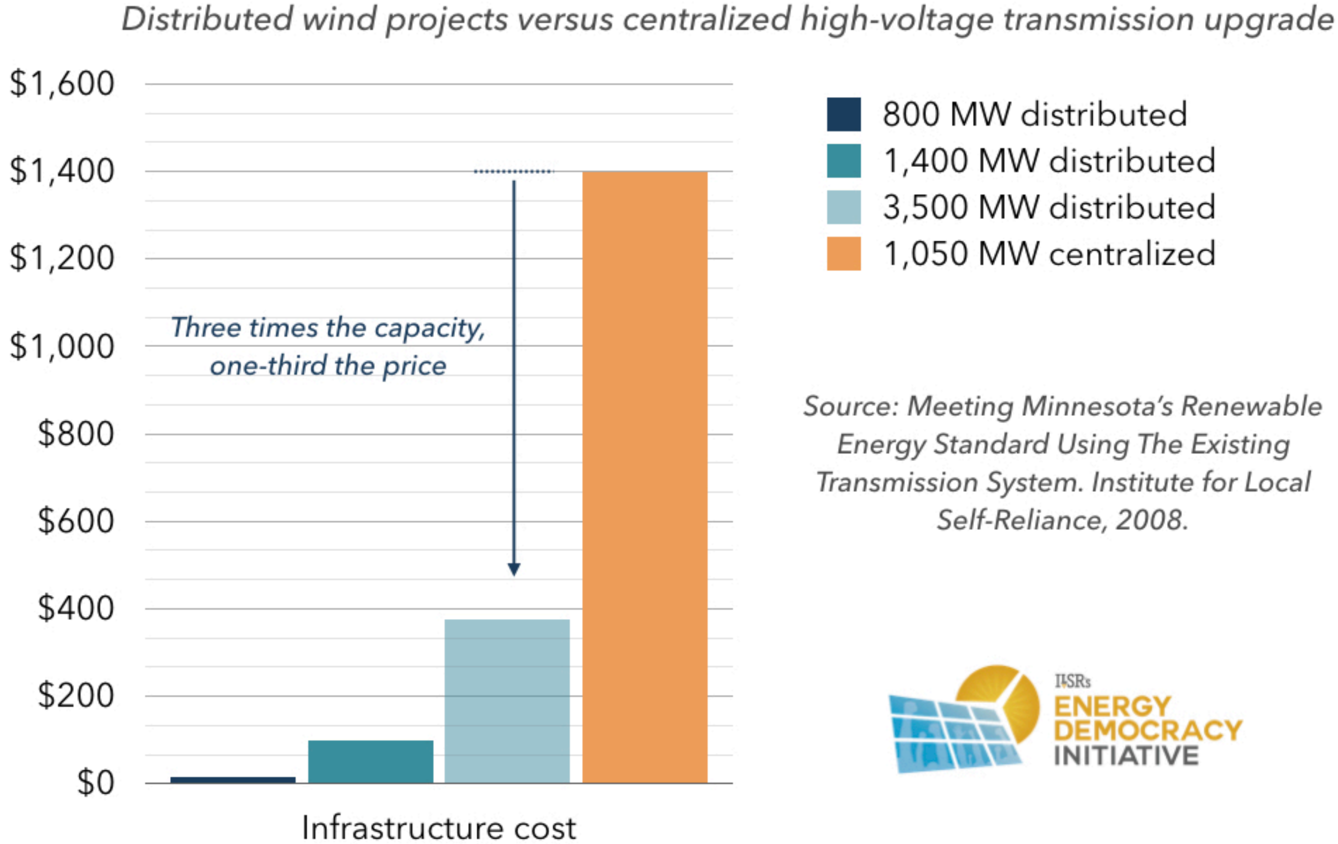
In 2005, a study of the West Central region of Minnesota identified a theoretical maximum of 3,500 megawatts of new wind capacity that could be added across 57 electrical substations, if connected to lower voltage distribution lines. At the time, the first 1,900 megawatts was forecast to replace gas generation, with additional capacity, up to the 3,500 megawatts, backing out (at the time) less expensive coal-fired generation from Wisconsin.[14]

In particular, the study showed that 800 megawatts of new generation could be added with zero to no upgrades to the existing transmission infrastructure. Up to 1,400 megawatts could be added with transformer and transmission upgrades totaling about $100 million (far less than adding new high-voltage transmission lines). Even the maximum amount, 3,500 megawatts, had forecast costs of $375 million, in comparison to the over $1 billion required to add 1,050 megawatts of new transmission capacity with the since-completed CapX2020 project.[15]

The study examined only an on-peak scenario, not off-peak energy delivery, but it is illustrative of the potential for significant integration of distributed energy resources. To the extent these sweet spots still exist, projects could materialize using the lapsed Distributed Generation Tariff or PURPA avoided cost contracts, should the Commission create the market opportunity.

14. Bailey, John, et al. Meeting Minnesota's Renewable Energy Standard Using The Existing Transmission System. (Institute for Local Self-Reliance, November 2008). http://bit.ly/2ZC1DHJ
15. Bailey, et al.

ESTIMATED GRID INFRASTRUCTURE UPGRADE COSTS



The West Central study provided a quick scan of four other Minnesota regions. If a similar portion were feasible (about 40% of the maximum), it indicated the potential to add 5,500 megawatts of distributed generation to the state's grid system at a modest system upgrade cost.

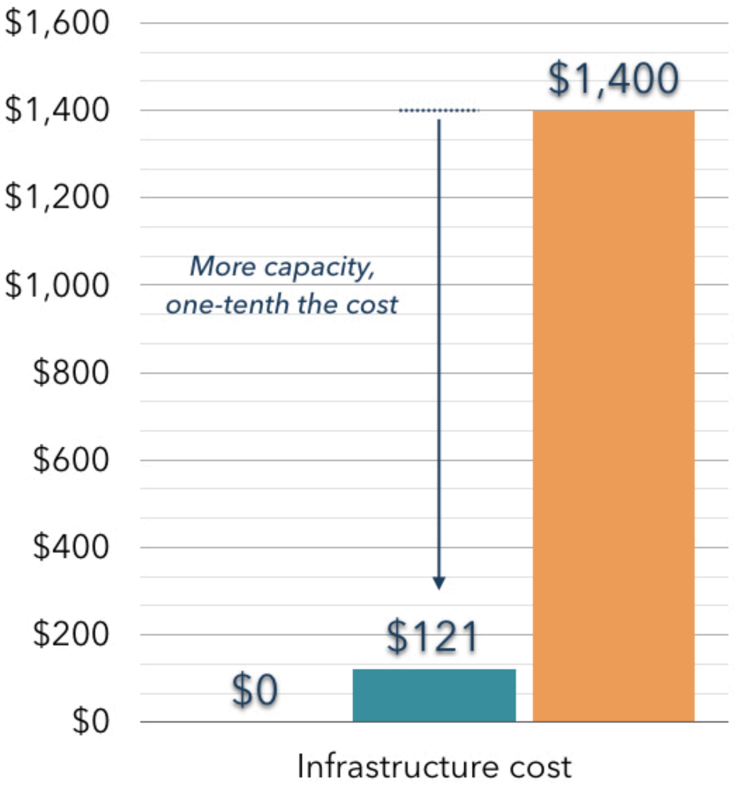
Follow-up Studies Support the First

The West Central study was followed by a legislatively-ordered statewide distributed generation study, completed in two phases in 2008 and 2009. The project took several months as it had to build a first-ever cross-utility model for examining lower voltage transmission power flows. Phase I identified twenty dispersed sites across the five state planning zones where a cumulative 600 megawatts of distributed energy generation (limited to 10 to 40 megawatts) could be added with zero transmission upgrade costs (unfortunately, the modeling exercise did not examine how much more could be added beyond the legislature's 600 megawatt ask).

Phase II of the study, released in 2009, examined adding a second 600 megawatts but made a major change in assumptions by including all projects in the MISO interconnection queue with signed interconnection agreements. Although there was plenty of local capacity shown available, the transmission constraints shown by the MISO assumption limited the aggregate opportunity to 50 megawatts **with no upgrades**. However, the study concluded that, "The statewide total to implement all the system upgrades necessary to achieve 600 MW of [distributed renewable generation] in Minnesota is just over $121 million."[16]

ESTIMATED GRID INFRASTRUCTURE UPGRADE COSTS

Distributed wind projects versus centralized high-voltage transmission upgrade



Source: Dispersed Renewable Generation Transmission Study, Volumes 1 and 2. Minnesota Department of Commerce, 2008-09.

Although the amount of renewable energy that could be built at a low infrastructure cost was remarkable, it's even more noteworthy that the potential existed despite the study's constraints: including so many potentially phantom projects with MISO interconnection agreements and failing to consider projects smaller than 10 megawatts.[17] The study's results suggest that **a core focus of utility resource plans and system planning include a deeper dive into distributed resource opportunities that minimize transmission costs**.

16. Dispersed Renewable Generation Transmission Study, Volumes 1-??
17. In testimony to the Wisconsin Public Service Commission, for example, distributed generation expert Bill Powers noted that only about 11 percent of projects in the MISO queue actually reach commercial operation. https://legalectric.org/f/2019/04/Direct-SOUL-Powers.pdf

PURPA and the "Hide the Peanut" Problem

With the distributed generation tariff proving ineffective and limitations on the community based energy development law, some project developers have sought to use the federal PURPA legislation to develop renewable energy in Minnesota. The law requires utilities to publish their "avoided costs" for obtaining new energy generation and capacity so that private developers can meet or beat that price.

Unfortunately, as one Minnesota developer has described it, Minnesota's utilities have played "hide the peanut," aided by the state's regulators. The federal law and Minnesota's matching state law require that avoided costs be available for "public inspection." Utilities, however, have successfully hidden their avoided costs behind a "trade secret" designation, unchallenged by the state Department of Commerce or Public Utilities Commission. The result is that Minnesota distributed generation project developers are caught in a Catch-22: they require financing to develop projects to the point of a contract negotiation with utilities (where utilities will finally share avoided cost prices); but without pricing data, developers can't get financing.[18] Some large, national developers have sufficient cash reserves or lines of credit that allow them to persist, but local or community distributed generation projects, in particular, often lack the financial backstop to develop projects without knowing if the price they'll receive will be sufficient.

Minnesota doesn't stand alone in this poor implementation of PURPA, but it also fails to reap the rewards of effective implementation. The federal energy competition law, PURPA, provides a framework for third party renewable energy projects to receive long-term contracts at fair prices, if properly enforced by state regulators. The following section details the cost-effective renewable energy deployment in states where PURPA-supported projects have flourished.

NORTH CAROLINA

In 2016, the Energy Information Administration reported that over 90 percent of North Carolina's 1,200 megawatts of utility-scale solar PV projects was due to its effective implementation of PURPA. Its report recounted that, "For North Carolina, utilities are required to establish up to 15-year fixed-avoided cost contracts for eligible solar PV qualifying facilities with a contract capacity of up to 5 MW."[19]

When Duke Energy asked state regulators to limit PURPA contracts to 10 years, the state legislature supported the move. However, the Commission refused the utility's proposal to adjust prices every two years.[20] As a result of the continued market certainty, solar capacity in North Carolina has continued to grow, eclipsing 4,000 megawatts, with many of the PURPA solar projects owned by a Duke Energy subsidiary.

As one might expect in a successful PURPA market, North Carolina also adheres to federal requirements for public avoided cost data. Duke Energy's avoided cost contract rates are available on their website, for public inspection.[21]

18. Petition for Reconsideration by the Environmental Law & Policy Center and Institute for Local Self Reliance. (Docket 19-9, 3/12/20). http://bit.ly/2QcHq8R
19. North Carolina has more PURPA-qualifying solar facilities than any other state. (Energy Information Administration, 8/23/16). https://bit.ly/3gZgnJO
20. Tait, Daniel. Dukeplicity on PURPA. (Energy and Policy Institute, 3/13/19). https://bit.ly/2ACTzPr.
21. SCHEDULE PP (NC)PURCHASED POWER. https://bit.ly/2XKb6gH

IDAHO

In Idaho, PURPA contracts led to significant growth in wind and solar projects until 2015, when utilities lobbied to slash PURPA contract lengths from 20 years to 2 years.[22] Idaho Power alone had over 1,100 megawatts under contract and nearly 1,300 megawatts in its interconnection queue.[23] The Public Utilities Commission agreed to reduce contract length, primarily to address the issue of knowing how avoided costs would change incrementally as new projects came online. However, the rule change effectively closed the market to PURPA projects, with Idaho Power reporting 1,120 megawatts of PURPA projects under contract in 2019.[24]

Unlike Minnesota, and in keeping with the federal requirements, the Idaho Commission requires all regulated utilities to publish avoided cost prices for public inspection on their website.[25]

Avoided Costs are Not-So-Trade-Secret Data in Idaho

IDAHO POWER COMPANY
AVOIDED COST RATES FOR WIND PROJECTS
June 01, 2019
$/MWh
New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects 100 kW or smaller.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2019	2020	2021	2022	2023	2024	CONTRACT YEAR	NON-LEVELIZED RATES
1	26.64	28.78	29.07	30.48	32.84	35.76	2019	26.64
2	27.67	28.92	29.75	31.62	34.24	37.13	2020	28.78
3	28.10	29.40	30.70	32.89	35.59	39.17	2021	29.07
4	28.63	30.16	31.82	34.16	37.40	40.41	2022	30.48
5	29.34	31.11	32.98	35.79	38.65	41.48	2023	32.84
6	30.21	32.13	34.44	37.01	39.74	42.32	2024	35.76
7	31.15	33.43	35.59	38.09	40.63	43.07	2025	38.62
8	32.33	34.49	36.63	38.98	41.42	43.74	2026	43.76
9	33.32	35.46	37.51	39.79	42.11	44.45	2027	44.76
10	34.23	36.29	38.30	40.50	42.84	45.14	2028	46.73
11	35.03	37.05	39.01	41.22	43.53	45.81	2029	47.66
12	35.77	37.74	39.72	41.92	44.20	46.45	2030	49.08
13	36.43	38.43	40.40	42.58	44.84	47.07	2031	50.18
14	37.09	39.08	41.05	43.21	45.46	47.66	2032	52.69
15	37.72	39.71	41.67	43.82	46.04	48.22	2033	54.54
16	38.33	40.31	42.27	44.40	46.60	48.76	2034	56.35
17	38.91	40.88	42.83	44.94	47.13	49.30	2035	58.07
18	39.46	41.42	43.36	45.46	47.65	49.80	2036	60.06
19	39.98	41.94	43.87	45.98	48.15	50.29	2037	61.52
20	40.48	42.43	44.37	46.46	48.62	50.77	2038	63.08
							2039	64.78
							2040	67.24
							2041	68.60
							2042	70.19
							2043	72.83
							2044	75.98

22. Walton, Robert. Idaho regulators trim renewables integration rates under PURPA for Rocky Mountain Power. (Utility, Dive, 12/11/17). https://bit.ly/36wv0PU
23. Cassell, Barry. Idaho PUC cuts the lengths of PURPA contracts for three utilities. (Transmission Hub, 8/24/15). https://bit.ly/2zzO0RJ
24. Ward, Xavier. Idaho Power's energy profile has gotten cleaner, but use of renewable energy proves a constant balancing act. (Idaho Press, 2/8/19). https://bit.ly/2ZDgCUQ
25. Idaho Public Utilities Commission, Electric Utilities. https://puc.idaho.gov/Page/Utility/2

UTAH

Prior to 2016, qualifying facilities in Utah were able to secure **20-year power contracts** with rates close to **five cents** per kilowatt-hour. Rocky Mountain Power, the state's largest utility, had over 1,000 megawatts of **projects operating** in 2016, with another 300 megawatts in the queue. Subsequent **changes** to contract length and pricing have made project development less attractive.

However, Rocky Mountain Power is required to publicly publish its avoided cost rates online. The following is an excerpt from their **2015 filing** (still effective in 2019).

Levelized Prices (Nominal)

	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
	Winter	Summer	Winter	Summer
15-year (2020-2034) Nominal Levelized	2.519	5.171	2.354	3.245

OTHER STATES WITH PUBLIC PRICING

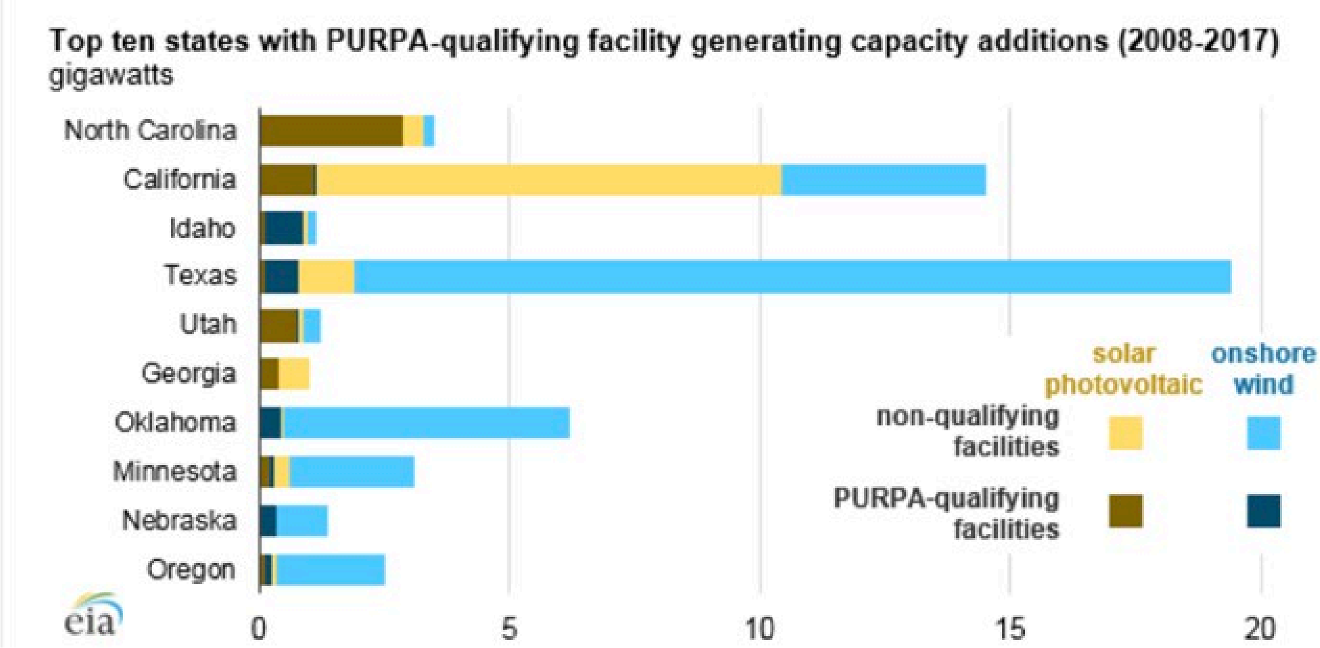
In addition to the states above, Oregon, Washington, and Wyoming also comply with federal requirements by having utilities disclose for public inspection the avoided cost rates for their utilities. The Renewable Energy Coalition, a network of qualifying facilities in the Northwest, maintains a **page with avoided costs** from these states plus Idaho and Utah.

Georgia, another state that has seen significant PURPA development, also has avoided cost data available for public inspection. For Georgia Power, the state's dominant electric provider, avoided cost projections are **published** in GPSC Docket No. 4822. Michigan regulators also recently revisited their PURPA compliance. Avoided cost rates for Michigan utilities are **publicly available**.

PURPA Nationally

Nationally, renewable energy development via PURPA has been significant, but also a significant minority of new power capacity in most years. According to the Energy Information Administration, "non-qualifying facilities" (built under competitive bid or other mechanisms) far outstrip qualifying facilities in capacity additions even in the top 10 states with PURPA qualifying additions **from 2008 to 2017**.

Only in North Carolina has PURPA resulted in a majority of new capacity, and only during a short window when the contract terms were favorable. In 2017, for example, "PURPA projects accounted for approximately **2,000 of the 4,500 MW** of solar energy production added in the United States," most in North Carolina.

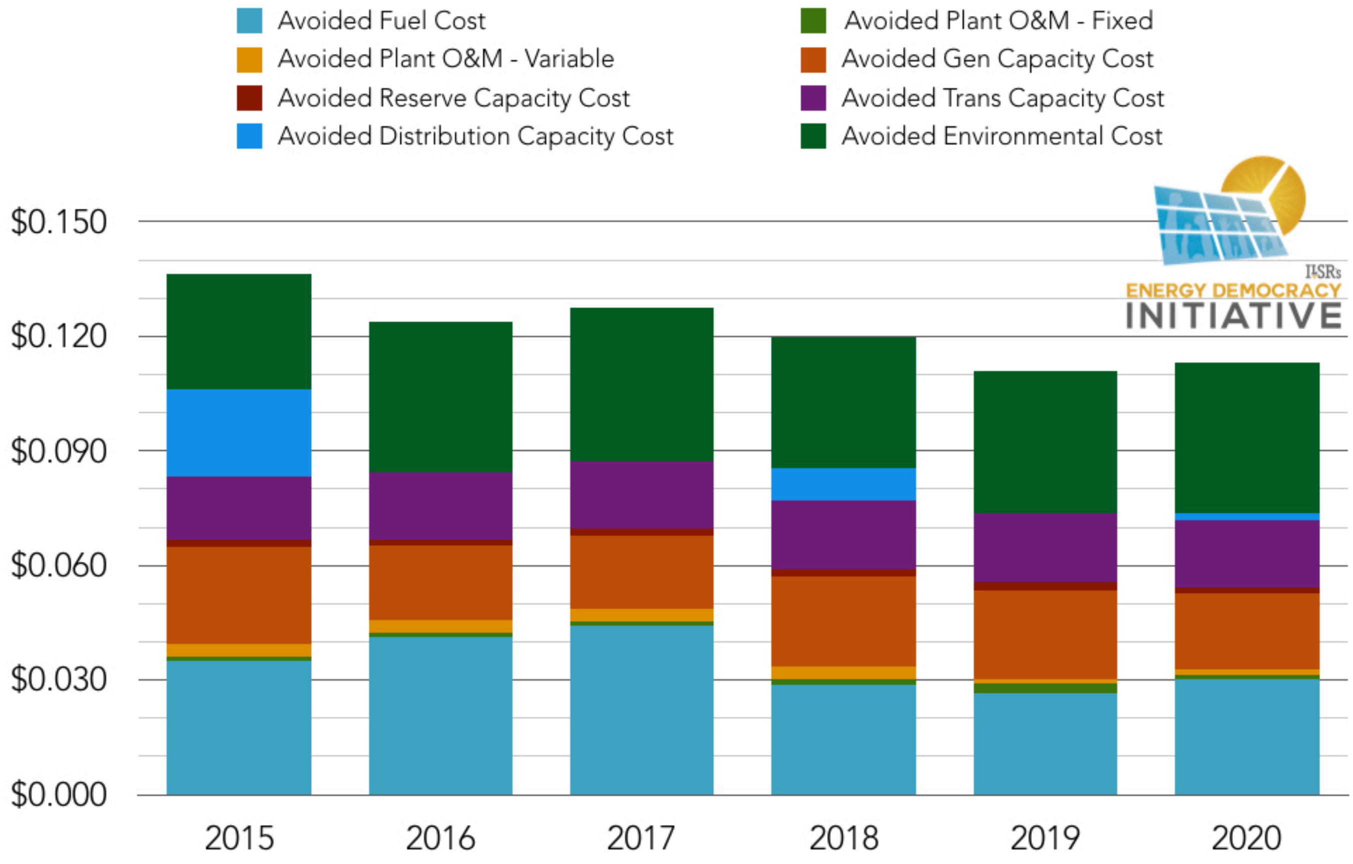


While PURPA might not be the main driver of renewable energy deployment, it's still been important in several states. And worth noting, most of the top states in PURPA deployment have a common theme: publicly available avoided cost pricing.

Getting Pricing Right

Although the biggest challenge for wholesale power in Minnesota and many other states has been transparent pricing and long-term contracts, getting the right price also matters. Several states have recently taken up efforts to identify the proper value of distributed energy resources connected on the distribution grid, such as Minnesota's value of solar policy. Minnesota's policy, for example, includes eight key components to accurately value solar energy's contribution to the grid. The 25-year contracts lock in the value of solar pricing that's available at the time the project secures a contract.

MINNESOTA'S VALUE OF SOLAR



In California, the state's Public Utilities Commission recently agreed to **include avoided transmission costs** in the avoided cost calculation for distributed energy projects.[26] While this won't affect every PURPA qualifying facility, it's sure to play a role in how renewable energy projects are sized and interconnect when transmission costs are "the fastest-growing component of electricity bills."

It's less common for this type of deep dive to include projects connected to the transmission system. In Michigan, an overhaul of PURPA implementation for utility Consumers Energy was completed in 2017, with significant changes to the program. Standard contracts were established for 20 years for projects 2 megawatts and smaller.[27] The Commission also modified avoided cost pricing to reflect replacement of natural gas generation, rather than coal. The new contract terms and prices resulted in **over 500 megawatts of new solar generation** in Consumers Energy territory between 2019 and 2020. The state also updated PURPA contracts for all other utilities, setting standard contracts for projects up to 550 kilowatts (or 1 megawatt) and establishing public avoided cost pricing.[28]

26. Misbrener, Kelsey. California PUC agrees to factor in avoided transmission costs when valuing distributed resources. (Solar Power World, 4/23/20). https://bit.ly/2ZHoODp
27. Gheorghiu, Iulia. Michigan regulators clear Consumers PURPA rates, green tariff programs. (Utility Dive, 10/8/18). https://bit.ly/36v77sd
28. Avoided Cost Fact Sheet. Michigan Public Service Commission. (2/6/20). https://bit.ly/2ywm9Bg

Recommendation

State regulators should carefully review forecasts for all non-utility resources that can impact resource plans, including wholesale distributed generation. State commissions have several ways to ensure an accurate forecast.

Like they have done with distribution system hosting capacity,[29] state regulatory commissions like Minnesota's Public Utilities Commission should require each regulated public utility to produce regular dispersed generation studies. In particular, these studies should identify available system capacity on the low-voltage side of high-voltage substations (115 kilovolt or less).

Additionally, state commissions should ensure that their implementation of state PURPA regulations guarantees public access to utility avoided cost data, as required by U.S. law. Multiple states already comply with the federal requirement to have avoided cost pricing available for "public inspection."

Finally, in states with additional statutory encouragement and policy meant to enable wholesale distributed generation, such as Minnesota, commissions should work to ensure that utility tariffs reflect the full value of distributed generation to the grid.

Conclusion

In the next three years, many U.S. utilities will present integrated resource plans to identify their plans for power generation for the next 10, 15, or 20 years. While these detailed plans frequently discuss additions of new fossil fuel power plant capacity owned or put out for bid by the incumbent utility, they often overlook renewable, distributed energy resources that could low energy costs, pollution, and deliver a more resilient electricity system.

Utilities have an incentive to get distributed generation forecasts wrong, because most profit by expending more capital on more utility-owned infrastructure. State regulators are often complicit in this problem, failing to ask for independent analysis of capacity expansion and infrastructure plans despite knowing of the utility's conflict of interest.

Evidence from many states suggests that distributed renewable energy can replace centralized power generation and provide additional benefits including customer energy bill savings, offsetting capital expenditures on system upgrades or expansion, reducing pollution, and providing resilience. The public interest requires a full exploration of how distributed generation can meet electric grid resources needs. In every state, public regulators should require that utility resource plans reflect a full and transparent assessment of the role of distributed generation in the future grid.

29. Hosting Capacity Map. (Xcel Energy, June 10, 2020). https://bit.ly/30uYzAs

Appendix

dGen Analysis for Minnesota

Without access to the sources formulas, ILSR modified the National Renewable Energy Laboratory's Kentucky dGen model for Minnesota based on the following differences:

- Minnesota's rooftop solar potential is 23% greater.[30]
- Minnesota had more distributed solar installed in the base year (2014) than Kentucky (19 versus 12 megawatts) but nearly 7 times more by 2018 (188 versus 25 megawatts)

All figures are in megawatts AC, adjusted where necessary with a ratio of 1.2, taken from the National Renewable Energy Laboratory System Advisor Model default ratio for DC to AC.

Minnesota Distributed Solar Forecast (Modified dGen model, Xcel territory, megawatts AC)

	2020	2022	2024	2026	2028	2030	2032	2034
LOW COST	159	187	232	304	417	587	834	**1165**
MID COST	154	165	187	224	287	385	532	**736**
HIGH COST	145	146	149	152	157	166	177	191

Williams, et al. Minnesota Analysis

The Willams model for rooftop solar deployment looks at market adoption based on the net-present value of a customer's investment in rooftop solar. The model has a good fit with actual adoption in several markets, including three U.S. states and two non-U.S. countries. ILSR built a Minnesota-specific version of the Williams model with the following assumptions:

- System size (kW): 4
- Cost per Watt: $3.50
- Capital cost: $14,000
- Subsidy, initial year: 26% Investment Tax Credit
- Annual production: 5000 kilowatt-hours
- Self consumption: 100% (all net metered)
- Retail price: $0.12
- Inflation: 2%
- Interest rate: 5%
- FIT price: n/a
- Solar life: 25 years
- FIT term: 25 years (net metering)
- K - 2000 megawatts per million households
- Mu - 7100 per kilowatt
- Sigma - 4110 per kilowatt

30. Gagnon, Pieter, et al. Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment. (National Renewable Energy Laboratory, January 2016). https://bit.ly/2oCR3lP.

In addition to these values, ILSR also added:

- 0.5% solar production degradation per year, per industry standards
- A baseline of 667,980 single-family, detached homes in the Minneapolis-St. Paul seven county metropolitan area (American Community Survey)

ILSR provided two forecasts using the Williams model. The Base Forecast included the following stipulations:

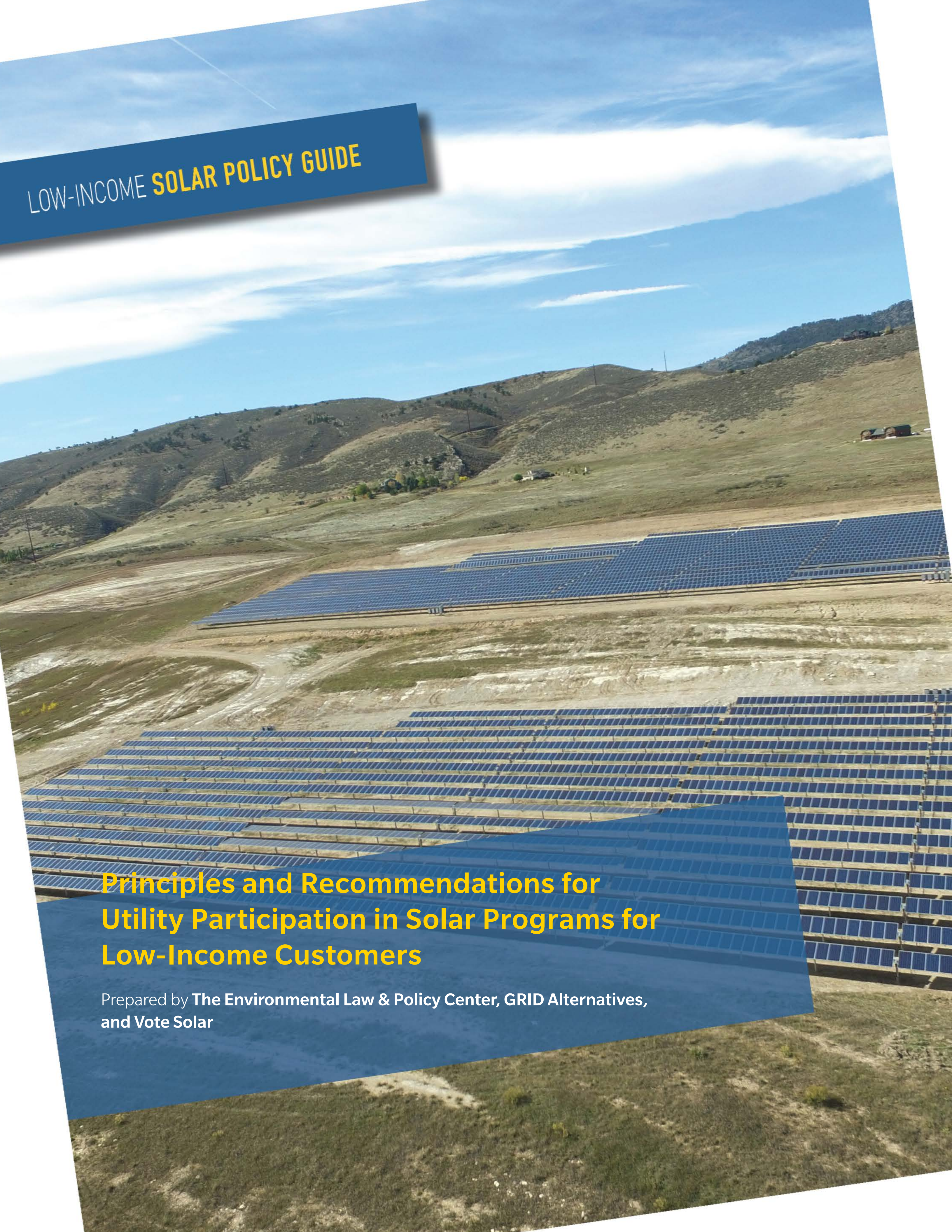
- The Federal Investment Tax Credit for residential projects expires as scheduled[31]
- Minnesota's Solar*Rewards program expires as scheduled after 2022
- The cost of solar declines at an annual rate of 5% (matching the five-year average)[32]

The High Forecast modestly adjusted some options:

- Instead of expiring in 2022, Minnesota's Solar*Rewards program phases out with a $0.005 reduction per year, starting at $0.07 in 2022.
- The cost of solar declines at an annual rate of 10% (matching the ten-year average and accounting for Minnesota's relative market immaturity)[33]

31 . Farrell, John. Congress Gets Renewable Tax Credit Extension Right. (ILSR, 1/5/16). https://bit.ly/37j1jCl
32 . Barbose, Galen and Naîm Dargouth. Tracking the Sun, 2019 Edition. (Berkeley Lab, October 2019). https://bit.ly/3gV-i9f3
33 . In the Tracking the Sun report, the authors noted that "smaller markets saw larger declines, suggestive of the greater cost-saving opportunities that may exist in less mature markets"

Low-Income Solar Policy Guide



LOW-INCOME **SOLAR POLICY GUIDE**

Principles and Recommendations for Utility Participation in Solar Programs for Low-Income Customers

Prepared by **The Environmental Law & Policy Center, GRID Alternatives, and Vote Solar**

LOW-INCOME SOLAR POLICY GUIDE

PRINCIPLES AND RECOMMENDATIONS FOR UTILITY PARTICIPATION IN SOLAR PROGRAMS FOR LOW-INCOME CUSTOMERS

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Acknowledgements

The authors of this paper appreciate the peer review and valuable feedback provided by the following reviewers:

Adam Browning, Vote Solar
Stan Greschner, GRID Alternatives
Brad Klein, Environmental Law & Policy Center
Annie Lappe, Vote Solar
Katie Ottenweller, Vote Solar
Ed Smeloff, Vote Solar

Thank you Julian Foley, GRID Alternatives, and Shabnam Nadiya, Vote Solar, for your essential contributions in editing this paper.

ENVIRONMENTAL LAW & POLICY CENTER

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PRINCIPLES AND RECOMMENDATIONS FOR UTILITY PARTICIPATION IN SOLAR PROGRAMS FOR LOW-INCOME CUSTOMERS

EXECUTIVE SUMMARY

Solar power is a cost-competitive, mainstream renewable energy resource that should be available to everyone, regardless of their income level or housing type. Yet America's nearly 50 million low-income households, who spend more on their energy needs as a percentage of income than their wealthier peers, are often unable to access or benefit from local solar resources. It is imperative that the country's transition to clean electricity meet the needs of underserved communities in a way that is inclusive and equitable.

Utilities are in a powerful position to facilitate the transition to clean energy for all and can play a vital role in expanding solar access and choice for low-income households. However, special care must be taken to ensure utility owned projects are designed to meet the needs of low-income households and underserved communities. In considering the roles utilities can and should play in making solar available for low-income households and underserved communities, this paper outlines three interrelated sets of guidelines and considerations for policy makers and regulators to review.

- Opportunities for Utility Facilitation of Low-Income Solar
- Considerations for Utility Development and Ownership of Solar for Low-Income Communities
- Guidelines for Successful Low-Income Solar Programs

Opportunities for Utility Facilitation of Low-Income Solar

Opportunities exist for all regulated utilities to facilitate solar access for low-income households *without* creating their own low-income solar programs. Utilities in any type of market can:

1. Facilitate customer enrollment in low-income solar programs in their service territories;
2. Facilitate customer education and engagement;
3. Facilitate on-bill payment and/or financing to increase low-income customers' access to rooftop solar;
4. Facilitate siting and interconnection for solar projects that will serve low-income customers;
5. Fully compensate low-income solar projects for the services and benefits they provide; and,
6. Facilitate donations of excess energy credits from other solar customers, and unsubscribed energy purchased by the utility from community solar projects, to low-income customers.

   In the case of community solar[1], utilities can also:

7. Enable virtual net metering along with an on-bill mechanism for billing and crediting community solar subscribers;
8. Serve as a "backup subscriber;" or serve as a "passthrough purchaser" to facilitate the purchase of solar on behalf of low-income customers;
9. Facilitate the participation of other large entities as backup subscribers and/or "anchor tenants;" and,
10. Establish streamlined processes for the portability and transfer of community solar subscriptions and regular updates to subscriber lists.

1 Community solar refers to a solar project with multiple subscribers that receive on-bill benefits directly attributable to the community solar project.

Considerations for Utility Development and Ownership of Solar for Low-Income Communities

Tasking monopoly utilities with developing and owning low-income solar can stifle low-income solar market activity by other providers, eliminating the benefits the competitive market can provide, including cost reductions, business model diversity, and the development of community-owned and operated enterprises. Therefore programmatic utility ownership of low-income solar projects should only be considered after a competitive market has had the chance, and failed, to serve the low-income market segment. A process for weighing this determination should include, at a minimum, the following:

1. Finding of low-income specific market failure;
2. Specific analysis of reasons the competitive market is failing to serve low-income customers;
3. Consideration of alternatives to utility ownership;
4. Establishment of boundaries within which the utility may act to correct a market failure, including regular re-evaluations of the original market failure finding;
5. Ongoing oversight of and reporting requirements on a monopoly utility's market participation; and,
6. Pilot project considerations.

Guidelines for Successful Low-Income Solar Programs

Finally, policy makers and regulators should ensure that low-income customers have access to solar through the development of low-income solar programs. Any low-income solar program must meet the following guidelines to provide meaningful benefits to participating households:

1. Provide immediate tangible economic benefits for low-income participants;
2. Fully compensate low-income solar projects for the services and benefits they provide;
3. Be designed as replicable, scalable programs for long-term program sustainability and opportunities for adjustment;
4. Include long-term funding to support programs, including low-income carveouts for any incentive pools;
5. Address barriers to participation for low-income households;
6. Complement existing programs to reduce overall household energy burden;
7. Drive local economic opportunity in underserved communities through workforce development and participation for minority- and women-owned business enterprises;
8. Prioritize community engagement throughout the program design, planning, implementation and ongoing operations, ideally through partnerships with local community organizations; and,
9. In the case of utility-owned projects, treat utility and non-utility owned projects equitably and follow the Considerations for Utility Development and Ownership of Solar for Low-Income Communities.

This paper provides decision makers and advocates with specific recommendations for the role of investor owned utilities in low-income solar programs, provides guidance for the type of programming that should be authorized and outlines steps to reach desired outcomes. While the guidance offered is intended to apply to programs and regulation of investor-owned utilities, many of these suggestions are applicable to municipal and cooperative utilities as well.

I. INTRODUCTION

A variety of factors, including quickly declining equipment costs and innovative financing models, have made solar easily accessible to middle income families in recent years; yet barriers remain for low-income families. The growth of solar in the United States provides a tremendous opportunity to address some important challenges faced by underserved communities: high energy burdens, unemployment, and pollution. Solar can bring long-term financial relief to families struggling with high and unpredictable energy costs; provide living-wage jobs in an industry where the workforce has increased 159% since 2010; and be a source of clean, local energy sited in communities that have been disproportionately impacted by traditional power generation.

As the nation's energy system incorporates more renewable energy and solar becomes a mainstream energy source, a key question facing the solar industry, policy makers, advocates, and regulators is how to make sure that all customers have access to solar technology and the benefits that come with it, not just those that can afford the significant upfront expense that solar can entail. The potential impact is huge. According to a 2018 NREL report, 43% of the U.S. population is at or below 80% of their area median income (the U.S. Department of Housing and Urban Development definition of low-income), representing almost 50 million low-income households in the U.S.[2]

Ensuring that solar energy is available for low-income households[3] and communities involves a variety of challenges. Cost sensitivity and often-limited access to financing makes it difficult to pay for solar installations. Furthermore, low-income families may live in homes that are not conducive to on-site solar installations because of the need for additional investment - such as roof repair - to be solar-ready, or simply because the home is a rental. Finally, outreach and education about solar for low-income communities entails its own challenges, as does enrollment. The variety of issues involved in expanding access to low-income individuals must be approached with care and reflect greater market dynamics to maximize benefits to end users.

In policy and regulatory arenas around the country, regulated investor-owned utilities are beginning to propose their own programs to facilitate greater solar access and, sometimes, actually provide solar for low-income households directly. Proposals relating to the direct provision of solar by utilities raise challenging questions regarding solar market impact and solar market inclusiveness, but they also create opportunities to consider appropriate roles monopoly utilities can and should play. Utilities have resources that can be used to overcome the challenges involved in delivering the promise of solar to low-income communities. These resources - including customer information, access to financing, existing billing systems, long-standing customer relationships, and the utility brand itself - can be used to facilitate cost-effective low-income solar solutions and widespread adoption.

However, while utility action to facilitate greater access to solar for low-income communities is always appropriate, participation in solar programs through the direct ownership (which may include construction) of projects is not always appropriate, particularly in restructured markets. It is important to ensure utility participation does not stifle the market's ability to drive down costs through competition, or edge out community-driven and nonprofit solutions, or undermine the ability of low-income customers and underserved communities to drive projects according to their goals, own assets, and build wealth. Utilities may be able to build solar projects quickly, particularly if they are able to recover costs from ratepayers. However, quick deployment does not always mean a project is cost-effective or in the best interest of customers. In an era where underserved communities are demanding more control over their own energy resources, utility ownership may not support

2 National Renewable Energy Laboratory, Rooftop Solar Technical Potential for Low-to-Moderate Income Households in the U.S. (2018), at https://www.nrel.gov/docs/fy18osti/70901.pdf.

3 For the purposes of this document, we define "low-income" as at or below 80% of Area Median Income, adjusted for family size and revised every five years.

energy democracy or the desire of communities for greater self-determination and local resiliency.

In this paper, we emphasize caution when considering utility ownership of projects, and offer thoughts relating to any utility-led programs that enable low-income solar development. We advocate special care when utilities actually build and/or own projects to ensure that these programs are in the best interest of low-income customers. Furthermore, low-income customers and underserved communities should have the ability to own and control community- or customer-sited distributed generation built through any utility-led program to avail of the same benefits enjoyed by non-low-income market participants. Additionally, utility-owned solar projects for low-income customers should not preclude efforts to spur market participation to serve this segment.

In considering the roles utilities can and should play in making solar available for low-income households and underserved communities, this paper outlines three interrelated sets of guidelines and considerations for policy makers and regulators to consider.

- Opportunities for Utility Facilitation of Low-Income Solar
- Considerations for Allowing Utility Development and Ownership of Solar for Low-Income Communities
- Guidelines for Successful Low-Income Solar Programs

After consideration of the Opportunities for Utility Facilitation of Low-Income Solar, and following the process outlined in the Considerations for Utility Development and Ownership of Solar for Low-Income Communities, and Competitive Market Considerations, policy makers and regulators should strive to ensure that **all** solar programs designed to serve low-income households meet the standards outlined in the Guidelines for Successful Low-Income Solar Programs. Special care should be given to proposals by investor-owned utilities, and especially IOUs in restructured jurisdictions, to ensure meeting these standards does not create an uneven playing field, stifle competition, or infringe on community self-empowerment.

In providing these recommendations, this paper raises various topics for consideration regarding utility ownership of solar projects and programs to serve low-income customers. The principles discussed and recommendations made are specific to serving low-income customers and will not always translate directly to utility participation in the distributed energy resources market more broadly. The authors hope that this paper is useful for decision makers and advocates in considering whether or not regulated utilities should develop solar programs and own solar projects for these customers, and the type of programming that should be authorized.

This paper begins by illustrating, in Section II, the types of actions all utilities - restructured or vertically integrated - can take to facilitate greater access to solar energy for low-income customers and households. Section III outlines important considerations for utility interactions with competitive solar markets in the process of serving low-income customers, including concerns around market failure. Section IV outlines specific recommendations for utility programs that will involve the development and ownership of solar energy systems. Finally, Section V outlines detailed guidelines for any successful low-income solar program. Two appendices compare specific utility programs to our recommended Guidelines.

II. OPPORTUNITIES FOR UTILITY FACILITATION OF LOW-INCOME SOLAR

There are a number of steps utilities can take to facilitate access to solar for low-income households short of developing an entirely new program aimed at low-income solar deployment. Policy makers and regulators should encourage regulated utilities to take these steps as relatively easy ways to break down barriers to solar access. As with the delivery of any utility-led initiative, care should be taken to ensure initiatives to facilitate solar access are streamlined, easy for customers to use, cost-effective, and do not hinder future competition. To achieve this, it is particularly important that utilities find ways to work with solar providers - who will actually build and sometimes own the solar projects - as well as community organizations.

Outlined below are a range of potential actions utilities can take to address the key barriers to low-income solar outlined at the beginning of this paper: cost-sensitivity and limited access to financing, physical/homeownership barriers, and challenges to outreach, education, and enrollment.

Utilities in any type of market can:

1. Facilitate customer enrollment in low-income solar programs in their service territories;
2. Facilitate customer education and engagement;
3. Facilitate on-bill payment and/or financing to increase low-income customers' access to rooftop solar;
4. Facilitate siting and interconnection for solar projects that will serve low-income customers;
5. Fully compensate low-income solar projects for the services and benefits they provide; and,
6. Facilitate donations of excess energy credits from other solar customers, and unsubscribed energy purchased by the utility from community solar projects, to low-income customers.

   In the case of community solar, utilities can also:

7. Enable virtual net metering along with an on-bill mechanism for billing and crediting community solar subscribers;
8. Serve as a "backup subscriber;" or serve as a "passthrough purchaser" to facilitate the purchase of solar on behalf of low-income customers;
9. Facilitate the participation of other large entities as backup subscribers and/or "anchor tenants;" and,
10. Establish streamlined processes for the portability and transfer of community solar subscriptions and regular updates to subscriber lists.

1. Facilitate Customer Enrollment

First, utilities may be able to facilitate customer enrollment in low-income solar programs. Customer enrollment can be a challenging and costly element of low-income solar program delivery. Utilities often have information about customers' income level and their participation in energy assistance programs, which could help low-income solar providers more effectively target potential program participants. For example, utilities can help to ensure that low-income customers participating in utility-provided energy efficiency programs are also enrolled in low-income solar programs. Utilities may also be able to facilitate appropriate access to certain customer information for low-income solar providers, or otherwise facilitate customer enrollment, e.g. by directing low-income customers to solar providers. When directly sharing data, care must be taken to ensure privacy is adequately safeguarded; however, in most situations this is a technical challenge rather than an insurmountable barrier.[4] Assurance that no undue preference is given to certain solar providers is also important to maintain an effective, competitive marketplace. Finally, utilities

4 Notably, the number of customers enrolled in energy assistance programs tends to be smaller than the number of customers eligible for assistance.

can assist in ensuring that customers' energy assistance program benefits mesh well with their participation in solar programs.

2. Facilitate Customer Education and Engagement

Likewise, utilities can facilitate customer education and engagement. Utilities are often seen as trusted sources of information. Utilities can engage in general customer education about solar and any existing low-income solar programs. Such education programs leverage the utilities' credibility and brand to enhance customer knowledge about solar and how customers can participate and benefit from it. Utilities should make any low-income solar educational material publicly available on their websites to ensure visibility and transparency, and should partner with community-based organizations to facilitate more direct forms of education. That said, care should be taken to avoid utilities acting as "gatekeepers" to solar providers and controlling the narrative about solar.

3. Facilitate On-Bill Payment and/or On-Bill Financing

Integration with utility bills can be effective for helping low-income customers pay for or finance their participation in both single-family and community solar programs. First, allowing customers to pay for their solar participation via their existing utility bill, even for third-party owned projects, streamlines the customers' experience. On-bill payment for low-income customers also mitigates perceived risk for solar providers and their financial backers. Going a step further, on-bill financing has been used successfully to finance energy efficiency measures and support expanded solar access. On-bill financing allows customers and financial institutions to use their electric bill as a means of repaying an energy-related loan. A customer will apply for a loan for a qualifying energy efficiency or other distributed energy resource or service and, upon approval, the loan payments are added to the customer's electric bill often at a level that is less than the overall savings achieved through the energy improvement. This type of program has many benefits to both customers and financial institutions. The Pay-As-You-Save model ("PAYS") is a successful example of on-bill financing. Under PAYS, customers pay a voluntary tariff on their utility bill in exchange for energy upgrades in homes and businesses. The tariff and repayment collection are implemented through the current on-bill system, limiting administrative burdens.

4. Facilitate Siting and Interconnection

Utilities are in a position to facilitate project siting and interconnection for solar projects that serve low-income customers. Utility property could be utilized to site projects, which could reduce project costs. Any co-development opportunities between utilities and solar developers or community groups to better serve low-income individuals should be considered. In addition, utilities can and should advise solar project developers about advantageous grid locations to interconnect as well as make that information publicly available.

5. Fully Compensate Low-Income Solar Projects for the Benefits and Services They Provide

Solar provides significant benefits to utility grids in terms of reliability, reduced capital investment, ancillary services, fuel diversity and fuel savings, and security. Additionally, bill savings and stability for low-income households as a result of solar participation can lead to fewer uncollectibles and fewer costs associated with disconnections, as these customers become better able to afford their electric bills. These values should be reflected in the compensation for low-income solar projects through performance incentives, rebates, compensation for excess energy generated, or other means.

6. Donations of Excess Credits and Unsubscribed Energy

Utilities can encourage and facilitate net metering customers and community solar project subscribers in donating excess energy credits they may have accrued on a monthly or annual basis. Additionally, utilities are generally required to purchase unsubscribed energy from community solar projects at an avoided cost rate. This too could be donated to low-income subscribers to help reduce their overall costs. Because of the value of offsetting grid-supplied energy costs, it would be preferable for donations to be energy (i.e. kWh). However, this method will sometimes entail more administrative work compared to an economic offset based on a monetization of the credits.

Community solar is a particularly important tool to enable low-income solar access, as it can overcome physical and homeownership barriers to solar installation. When it comes to community solar - regardless of who owns such a project - utilities can facilitate the successful development and implementation of programs and projects in a variety of ways.

7. Community Solar: Virtual Net Metering and On-Bill Crediting

Utilities should enable virtual net metering along with an on-bill mechanism for billing and crediting community solar subscribers. All subscribers, but particularly low-income subscribers, will benefit from having community solar subscriptions consolidated onto their existing utility bill to minimize the number of bills they must pay to various providers. Second, utilities must facilitate the timely and transparent application of bill credits to promote customer-friendly offerings. This allows individuals to easily understand the benefits they receive as part of any virtual net metering arrangement.

8. Community Solar: Utility as Backup Subscriber or Passthrough Purchaser

One of the major barriers facing developers of low-income community solar projects is access to financing due to potentially low credit scores and other perceived risks around low-income subscribers (e.g. turnover rates). Utilities can mitigate this financing risk by serving as a backup subscriber or passthrough purchaser, thereby facilitating access to, and a lower cost of, capital[5]. As a "backup subscriber," the utility agrees to purchase a low-income subscriber's energy in the event the subscriber falls off the rolls. As a "passthrough purchaser," the utility facilitates the purchase of an entire community solar array's output, while facilitating the application of community solar credits to participating customers' bills.[6]

9. Community Solar: Facilitate the Participation of Large Subscribers to be Backup Subscribers or Anchor Tenants

Utility facilitation of low-income community solar projects can also involve work with state governments, local governments or large commercial and industrial customers to serve as anchor tenants and off-takers of excess energy due to under-subscription or turnover. Backup subscribers or anchor tenants are often used to increase community solar project financeability. These entities are typically institutional or creditworthy entities that financiers are confident will pay for their subscription over the contract term. Dedicating a significant portion of a community solar facility's output to an anchor tenant (e.g. 30% - 60%) can provide more flexibility for the types of customers the remaining facility output can serve. Large subscribers participating in a project as anchor tenants not only de-risks the project, they can also voluntarily subsidize any subscription offering for low-income households to provide greater savings. In addition, these customers can also serve as backup subscribers in case low-income households fall off the subscriber list. In effect, a backup subscriber can reduce or eliminate the amount of unsubscribed energy. A backup subscriber can ensure that a community solar project is always fully subscribed, thus maximizing the value of the facility's generation and further reducing the perceived risk of serving low-income households.

10. Community Solar: Establish streamlined processes for the portability and transfer of community solar subscriptions and regular updates to subscriber lists.

Transferability refers to the ability for shares to be transferred back to the community solar provider and from one participant to another participant. Portability refers to the ability of a participant to "bring their subscription with them" when they move within a utility's service territory. Both are important consumer protection policies in any community solar program; however, they are particularly critical policies for low-income households that are less likely to own their own home and stay in one place for long periods. Turnover of subscriptions should be expected over the 20-to-30 year lifespan of a community solar project and can often be managed at very little cost by community solar providers through a subscriber waitlist or other mechanism. To this point, it is critical that utilities establish a standardized process (e.g. an online portal) that allows for monthly updates to subscriber lists so that the project can remain fully subscribed at all times.

Coyote Ridge Community Solar Farm

Poudre Valley Rural Electric Association's (PVREA) 1.95 MW Coyote Ridge Community Solar Farm enables low-income participation through an on-bill repayment process. This approach builds upon existing cooperative utility Pay-As-You-Save (PAYS)™ models for low-income community solar. Like a PAYS™ model for energy efficiency improvements, the program offers a community solar subscription in which the savings from solar production exceeds the cost of the subscription. Low-income cooperative members have no upfront capital requirements to receive the expected solar benefit, and are required to participate in a mutually beneficial energy efficiency program to maximize impact. 700 kW of the project is dedicated to low-income customers, 500 kW to nonprofits, and the remaining 750 kW of capacity to all other utility customers, who pay a slightly higher cost for participation to help enable the low-income customer benefit. This project, developed in partnership with GRID Alternatives as part of the Colorado Energy Office (CEO) Low-income Community Shared Solar Demonstration Project[7], was awarded a 2018 Power Player Award from the Smart Electric Power Association (SEPA).

III. COMPETITIVE MARKET CONSIDERATIONS

Utilities have a natural advantage when it comes to low-income solar deployment in many markets as large, established entities with pre-existing customer relationships. Utilities may also serve as the provider of last resort in restructured markets. Given these advantages, significant care should be taken to not default to utility-led low-income solar programs that edge out competitive market and community-driven solutions. Rather, competition should be encouraged as a way to minimize program costs and maximize benefits to end-users. Competition spurs innovation and delivers low-cost solutions that can maximize benefits to low-income households.Most importantly, it can give communities the opportunity for local control,

7 An initiative working to develop low-income community solar projects in Colorado that complement the state's low-income weatherization program to achieve significant energy burden reduction for low-income ratepayers.

decision-making and ownership in any low-income project.

At a minimum, utility involvement in low-income solar should enable community organizations and the solar industry to provide market-based approaches to effectively serve low-income communities. However, the best programs will actively foster innovation among community organizations and the solar industry, spurring collaboration with community groups and competitive market participants to develop new and better ways to serve low-income communities.

When considering the role of regulated utilities in making solar available to low-income communities, advocates, policy makers, and regulators should focus on enabling the broad use of assets and capabilities that utilities have access to, and which all ratepayers have paid for, rather than allowing utility monopolization of those assets. Utilities can participate in solar programs for low-income customers by facilitating appropriate access to assets such as customer lists, usage data, billing capabilities, etc. for all low-income solar market participants. Policy makers and regulators should discourage monopolization of these types of assets or other singular treatment not available to the open market, as this creates barriers to community and competitive market involvement in low-income solar. An example of monopolization of assets could include a situation where only utility-owned community solar projects were able to consolidate crediting on customer bills or utilize information about enrollment in income-limited programs to target outreach. Singular treatment extends to exceptions to rules – such as those around project size, access to subsidies and ratepayer funds, or any other unique advantage.

Regulated utilities should be encouraged to participate in low-income solar markets in ways that facilitate overall market growth of low-income solar offerings. Regulated utilities can play an important role in serving low-income customers. However, in doing so, any utility-led program should incorporate the opportunity for fair market competition to ensure that low-income individuals are obtaining the most competitive offerings and adequately compensated for the array of benefits solar projects provide to the grid. One way utilities in vertically integrated markets can do this is through their energy procurement processes. This can be achieved by structuring procurements for specific projects, for example community solar projects with a significant share or all of project capacity dedicated to low-income customers. Utilities can also drive impact and important co-benefits through these procurement processes by including minimum bid requirements or qualitative factors within procurements, including minimum bill savings or overall energy burden reduction, energy efficiency and other complementary low-income energy services, and workforce development. Utilities can expand economic opportunities through procurement by requiring or encouraging projects owned or led by disadvantaged business enterprises, or requiring a minimum percentage of labor from these types of entities within project implementation scope[8]. In restructured markets, it is not clear that this tool is available, but may be an avenue regulators could explore.

Furthermore utilities should strive to partner with the communities their programs will serve, both in the program design and delivery stages of the project, rather than delivering a ready-made solution. Doing so will help spur market innovation, support a diversity of low-income solar consumer offerings, and enable programs tailored to best serve the community. As demonstrated in Colorado, utilities can serve as helpful partners to small organizations and businesses working to provide low-income solar.[9]

8 As an example, Xcel Energy Colorado's Solar*Rewards Community Low-income Request for Proposals includes quantitative (bid price) and qualitative factors including bill savings, coordination with energy efficiency measures, and job training. The RFP also includes a weighting matrix for how these factors are evaluated.

9 See, e.g., GRID Alternatives, "Five New Community Solar Projects!" available at http://www.gridalternatives.org/regions/colorado/news/five-new-community-solar-projects (GRID Alternatives partners with various municipal and cooperative utilities to construct and operate community solar projects to serve low-income customers). See also "Colorado Energy Office, Energy Outreach Colorado and GRID Alternatives Colorado Collaborate to Create Milestone Low-Income Solar Access," available at http://www.prnewswire.com/news-releases/colorado-energy-office-energy-outreach-colorado-and-grid-alternatives-colorado-collaborate-to-create-milestone-low-income-solar-access-300365336.html ("The Xcel Energy settlement also creates a favorable market in which low-income solar offerings can thrive by providing developers access to new customers and assisting the utility in meeting its goals. The settlement

Among other things, policy makers and regulators may want to consider the speed with which low-income solar projects are built. Utilities may be able to deploy solar in low-income communities faster and at a greater scale than any other entity. It takes time for communities to organize and competitive markets to develop, which can further delay solar access in historically underserved communities. However, a market served by many small institutions and community-based organizations provides more opportunities for community ownership and empowerment, offers the potential to maximize economic benefits, and is often more resilient to change than a single large program. The short-term and long-term tradeoffs need to be weighed carefully and should be considered during any program review and redesign period. In addition, policy makers and regulators must consider the utility's established customer relationship and trusted brand as inherent advantages to any low-income solar offering. Expanding low-income consumer choice and access to diverse business models during any program review and redesign period should be a key focus.

IV. CONSIDERATIONS FOR UTILITY DEVELOPMENT AND OWNERSHIP OF SOLAR FOR LOW-INCOME COMMUNITIES

Questions about regulated utility development and ownership of solar can raise contentious issues. *First,* in this paper, when we discuss low-income solar, we are specifying the benefits solar can bring to low-income consumers as a power generator. In restructured markets, utilities are generally prohibited from building or owning solar generation, distributed or otherwise, as the competitive market is fully able to meet generation requirements without public support via a guaranteed rate of return.[10] This paper does not address the potential for solar to serve as a distribution asset or the questions about utility business model motivations or incentives that potential may raise.

Second, generally speaking regulated utilities – restructured or not – should not build or own distributed generation behind a customer's own meter unless there are compelling public policy reasons to extend the utility monopoly into the competitive private market.

Third, community shared solar is a relatively new model; with this model, there are significant questions about the appropriateness of monopoly utility ownership even in vertically integrated markets where the ownership of generation is generally allowed. The authors note that there is a burgeoning competitive community solar market in the US, which raises the question of whether there is a public interest served by regulated monopolies providing community solar. Regulators should carefully examine whether this is an arena more appropriately left to the competitive market.[11]

However, when it comes to low-income solar, questions sometimes arise related to the competitive market's ability or willingness to serve this customer segment. Theoretically, if the provision of low-income solar is an agreed upon public policy objective and the competitive market is unable or unwilling to serve these customers, it may be appropriate to socialize the costs of that provision through a monopoly utility ***even when the utility would not otherwise be eligible to develop or own generation.***[12] This paper discusses competitive market considerations in more detail below.

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offers solar developers access to incentives and performance structures as in the mass market. It also provides options to overcome traditional barriers to low-income customer engagement such as access to capital, lender related risk, and new market exploration. Additionally, the settlement creates structures to encourage workforce development and job training.")

10 Exceptions do exist, however. See, for example, Massachusetts General Laws Part 1, Title XXII, Chapter 164, Section 1A(f) which notes explicitly that the deregulation of generation facilities does not "preclude an electric company or a distribution company from constructing, owning and operating generation facilities that produce solar energy; provided, however, that such company shall not construct, own or operate more than 35 megawatts of such facilities, …" https://malegislature.gov/Laws/GeneralLaws/PartI/TitleXXII/Chapter164/Section1A

11 Vote Solar and the Interstate Renewable Energy Council developed A Checklist for Voluntary Utility-Led Community Solar Programs. This document can help regulators evaluate the merits of any voluntary utility-led community solar program and is available at www.votesolar.org/cschecklist.

12 Reference Appendix B for an analysis of a utility-owned low-income project in a restructured market.

Finally, decisions about the appropriateness of the exception from the typical norms that govern monopoly utilities' ownership of generation should happen on a case-by-case and market-by-market basis. It may be appropriate to consider singular pilot projects intended to generate learnings and identify other steps needed to facilitate the development of a low-income solar market as long as competition and an appropriate evaluation process is included as part of the pilot program.[13] However, when considering more programmatic exceptions to norms around utility ownership, regulators should address the considerations for utility development and ownership of solar for low-Income communities outlined below through a formal process that includes stakeholder input before making any such exceptions:

1. **Finding of low-income specific market failure.** The competitive solar market must have had a meaningful chance to serve the low-income market segment and failed to do so. In markets without fair compensation for energy put back on the grid, adequate incentives, or an existing community solar program structure that expands access to consumers who cannot access benefits from rooftop solar, the lack of a low-income solar market is not a reflection of a market failure, but rather of barriers to solar energy generally. These barriers must be removed and the market allowed time to develop before it is reasonable to find that the market is failing to serve low-income customers. Section V: Guidelines for Successful Low-Solar Programs of this report provides suggestions for addressing barriers.

2. **Specific analysis of reasons the competitive market is failing to serve low-income customers.** Understanding the reasons for a market failure is the key to determining how best to address that failure. For example, if the issue is low and no credit scores amongst low-income households, one solution may be to require the monopoly utility to take on credit risk on behalf of a developer, while another may be to establish a Green Bank that provides financial backstops. All policies and regulations must be considered during the analysis and must include a stakeholder process that invites third-party providers to comment on barriers that prevent low-income participation.

3. **Consideration of alternatives to utility ownership.** Notably some of the most successful low-income solar programs in the US delivering behind-the-meter solutions, including the Single-Family Affordable Solar Homes program, the Multifamily Affordable Solar Homes program, and the Low-Income Weatherization Program solar rebate programs in California, DC's single-family rooftop rebate program, and Colorado's Low-Income Community Shared Solar Demonstration Project, have involved socialized costs (i.e. through ratepayers or taxpayers) without deploying the solar projects through monopoly utilities. Therefore, it is appropriate to consider alternative strategies before determining that monopoly utilities are best positioned to correct a market failure.

4. **Establishment of boundaries within which the utility may act to correct market failure, including regular re-evaluations of the original market failure finding.** If exceptions to typical norms around monopoly utility ownership of generation (in restructured markets) are going to be made to address a market failure, the bounds of those exceptions must be clearly delineated. One of these bounds should be a time limit, after which the regulator will re-evaluate the original finding of a market failure. This re-evaluation is important because the solar market is dynamic and fast-changing, and as prices for solar continue to fall and efficiencies are gained, the competitive market may become better positioned to serve low-income customers. It's important to note that in this case, previous utility investments would need to remain in the rate base and receive full cost recovery.

5. **Ongoing oversight of and reporting requirements on monopoly utility's market participation.** Ongoing oversight is necessary to ensure appropriate use of public resources and to ensure inappropriate market advantages do not accrue to the utility (e.g. ensuring competitive bidding processes). The knowledge gained by the utility from

13 The pilot program can incorporate competition in a variety of ways, such as with the engineering, procurement, development or ownership of the project. In addition, pilot program metrics must be captured throughout the project to properly evaluate the success of the pilot and provide transparent reporting. This reporting and evaluation process is critical to generate learnings, facilitate the development of a low-income market, and determine the replicability and scalability of a low-income community solar pilot in a particular market.

both successes and failures in providing low-income solar is a public resource, since it was gained using ratepayer funds. Allowing other community organizations and market players to benefit from this knowledge is not only the right thing to do, but will further the agreed upon public policy objective of expanding solar access among low-income customers. Any utility-owned low-income solar proposal and subsequent program must undergo annual regulatory review and public comment periods, with meaningful stakeholder engagement opportunities. Program effectiveness can be measured in a variety of ways, but at a minimum must include evaluation of benefits for low-income customers, number of participants including breakdown by housing type (e.g. single family homeowner, affordable housing tenant, renter, etc.), length of individual participation, strategies for education and enrollment, opportunities for fair market competition, and a review of the level of community engagement (community involvement in planning, decision making, program implementation, and through local job creation). Reviews may also evaluate the distribution of benefits and/or progress toward community-defined goals.

6. **Pilot project considerations.** While utility-owned low-income solar projects may sometimes be appropriate outside of a market failure situation if delivered through a singular pilot project, the goal of any such pilot must go beyond simply the deployment of a certain number of kilowatts or megawatts of low-income solar. Low-income solar pilot projects should seek specific learnings and/or trial innovative approaches to low-income solar deployment. Their learnings and results should create new, readily available roadmaps and tools to facilitate and catalyze further expansion of low-income solar. However, the second consideration discussed above - that utilities generally should not build or own distributed generation behind a customer's meter - should apply to a pilot scenario, as well.

V. GUIDELINES FOR SUCCESSFUL LOW-INCOME SOLAR PROGRAMS

Utilities can address the financial barriers that face low-income customers and low-income solar providers by designing new programs targeted specifically at low-income solar deployment. These programs may include incentive programs such as rebates, production-based incentives or singular low-income community solar pilot projects. More examples of successful low-income programs may be found in the Low-income Solar Policy Guide.[14]

Once review has been given to proposals by monopoly investor-owned utilities, and especially IOUs in restructured jurisdictions, to ensure such programs are in the public interest and do not create an uneven playing field or stifle competition, policy makers and regulators should ensure that the programs meet the following standards. We emphasize that these guidelines must be met with any low-income solar program to provide meaningful benefits to participating households:

1. Provide immediate tangible economic benefits for low-income participants;
2. Fully compensate low-income solar projects for the services and benefits they provide;
3. Be designed as replicable, scalable programs for long-term program sustainability and opportunities for adjustment;
4. Include long-term funding to support programs, including low-income carveouts for any incentive pools;
5. Address barriers to participation for low-income households;
6. Complement existing programs to reduce overall household energy burden;
7. Drive local economic opportunity in underserved communities through workforce development and participation for minority- and women-owned business enterprises;
8. Prioritize community engagement throughout the program design, planning, implementation and ongoing

14 https://www.lowincomesolar.org

operations, ideally through partnerships with local community organizations; and,

9. In the case of utility-owned projects, treat utility and non-utility owned projects equitably and follow the Considerations for Utility Development and Ownership of Solar for Low-Income Communities.

In addition, if it is determined that regulated utilities should be allowed to own low-income solar programs or projects (see Section IV, Considerations for Utility Development and Ownership of Solar for Low-Income Communities), they must be crafted so as to maximize value for low-income participants and maintain opportunities for competition. This includes maximizing bill savings to reduce the energy burden for low-income customers within state average thresholds, coupled with opportunities for meaningful community engagement and co-benefits such as coordination with job training programs while encouraging strong participation from a range of third party participants.

1. Provide immediate tangible economic benefits for low-income participants.

Ensuring immediate tangible economic benefits for participating low-income customers should be the top goal of any low-income solar program. Low-income households spend a disproportionately higher percentage of their incomes on energy, as compared to other households, more than three times higher on average.[15] This problem is gaining increasing recognition: the State of New York recently established an "energy burden" target of six percent, meaning that a family's spending on energy should not exceed six percent of their income. The energy burden for many low-income families is much higher. Low-income solar programs should target meaningful customer savings, with a goal of bringing energy bills into an acceptable range with regard to families' energy burdens; and savings should accrue starting on day one of a low-income household's participation. A utility proposal that offers savings of only a few dollars per month would generally not meet this standard.[16] Ultimately all programs should set a minimum savings target and take into account stakeholder input and data on median local energy burdens when developing that target. For example, the Solar for All program administered by the District of Columbia Sustainable Energy Utility includes a minimum savings goal of 50% for participants.[17]

2. Fully compensate low-income solar projects for the services and benefits they provide.

As discussed above, to the extent that low-income solar projects provide benefits to the grid in the form of reduced investments or ancillary services, for example, these benefits should be fully recognized in any analysis of program costs and benefits and reflected in the ultimate value offered to low-income subscribers.

Additionally, utilities can be rewarded for exemplary low-income solar project design and performance, and they can reward competitive projects for the same good design and performance. For example, if projects have grid-related benefits, regulators should consider not only how to compensate project owners for those benefits, but also how the utility should appropriately account for and, in some cases, be compensated or rewarded for those benefits.

3. Be designed as replicable, scalable programs for long-term program sustainability and opportunities for adjustment.

Going hand in hand with the requirement for meaningful savings and tangible economic benefits for participating low-income households, low-income solar programs must be designed with an eye toward long-term sustainability

15 https://aceee.org/press/2016/04/report-energy-burden-low-income

16 See, e.g., Petition of Excel Energy of MN for Approval of a Customer Access Joint Pilot Program, Docket # M-17-527 (2017), available at 20176-133411-01, in which Minnesota Power proposed low-income customer community solar participation, among other things, for which it estimated customers would save, on average $2.16 per month.

17 https://www.lowincomesolar.org/best-practices/single-family-district-of-columbia

and opportunities for program adjustment. Programs should be reviewed periodically to identify opportunities for improvement, with meaningful stakeholder engagement incorporated into the review process. To that end, any program should capture metrics related to customer economic benefits, participation targets, customer satisfaction, and community engagement, among others. Periodic reviews should also evaluate the competitive solar market to determine if any utility low-income solar programming should be scaled back in response to greater interest and capabilities of the solar market.

4. Include long-term funding to support programs, including low-income carveouts for any incentive pools.

Long-term funding is an essential component of successful low-income solar programs. Funding to support meaningful savings and tangible economic benefits for participating customers must be sustained and sustainable. Stop and start programs create uncertainty amongst both consumers and market participants, ultimately breeding a climate of distrust and making it difficult for the next program to succeed.

Low-income solar programs are funded through a variety of sources. The most successful programs operating today include a long-term funding source to support dedicated, differential incentives for low-income customer solar adoption. Programs are funded through public purpose charges, riders, noncompliance or alternative compliance funds, ratepayer funded incentive pools, or revenues from carbon or renewable energy credit markets. In any approach, it is essential to include the foundational principle of equity within funding mechanisms and incentive pools for solar and renewable energy adoption. This can be achieved through an equity budget, low-income carveout, or carveouts for other demographics, such as states that use "disadvantaged communities"[18] or other definitions and metrics for underserved population segments. If low-income customers pay into a pilot or program's incentive pool as ratepayers or taxpayers, which is generally the case, low-income incentives should be budgeted at least in proportion to their contribution to the incentive pool. This policy ensures that all taxpayers or ratepayers who contribute to the solar initiative, including low-income households, also have equitable access to receive the benefits of the program.

5. Address barriers to participation for low-income households.

Low-income solar (and more broadly, energy) programs generally require design that is differentiated from market-rate programs, to account for the unique barriers faced by low-income customers. These barriers include addressing upfront cost and financing barriers and ensuring deep energy cost savings through minimum savings requirements or other tracking metrics.[19]

6. Complement existing programs to reduce overall household energy burden.

Low-income solar programs and policies should integrate well with synergistic programs such as low-income energy efficiency, healthy home programs and others that address the intersection of equity, energy, and infrastructure, and, when combined, provide the greatest opportunity for energy burden reduction. Integrating low-income solar programs with existing low-income programs and services can also mitigate implementation challenges such as income verification and build on trust created by successful existing programs.

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18 California utilizes a definition of Disadvantaged Communities (DACs) within state energy programs, informed by the mapping tool CalEnviroScreen. https://oehha.ca.gov/calenviroscreen/sb535

19 These may include minimum savings goals or requirements, minimum energy burden reduction targets, or savings-to-investment ratio requirements as included in federal weatherization programs https://www.energy.gov/sites/prod/files/2017/01/f34/107598_WAP_FS_v1b.pdf

7. Drive local economic opportunity in underserved communities through workforce development and participation for minority- and women-owned business enterprises.

Low-income solar programs provide an ideal opportunity for incorporation of workforce development components that provide job training opportunities and direct pathways to employment in solar for local workers in underserved communities. Additionally, providing business opportunities for local minority- and women-owned businesses is emerging as a best practice. For example, the NAACP outlines best practices for equity in energy procurement in their Just Energy Policies Compendium including policies to support minority- and women-owned businesses. These types of program elements will ensure that low-income solar programs provide community economic benefits beyond household savings.

8. Prioritize community engagement throughout the program design, planning, implementation and ongoing operations, ideally through partnerships with local community organizations.

All low-income programs must include commitment to and planning for deep community engagement in the project design and planning process, with ongoing engagement after the project is complete. As a starting point, regulators should require low-income solar providers to develop a plan for community outreach and education, which must be in place and implemented at the beginning of the planning and design process. Trusted local community-based organizations must be included in all key decisions around program or project planning, design and implementation. Without community buy-in and an agreed upon plan for the provider to follow, outreach and trust building may not be as successful. Engagement should include partnerships with trusted local community-based organizations, which can help educate and enroll customers. Furthermore, where desired by local community-based organizations, programs should explore ways to facilitate community ownership of projects.

9. In the case of utility-owned projects, treat utility and non-utility owned projects equitably and follow the Considerations for Utility Development and Ownership of Solar for Low-Income Communities.

As outlined above, utilities have a natural advantage when it comes to low-income solar deployment because they are large, established entities with pre-existing customer relationships. Regulated utilities should be encouraged to make solar available to low-income customers in ways that both facilitate the overall growth of low-income solar markets and encourage strong third party participation in these markets. If a policy-making body or regulator makes the determination that utility-owned low-income solar is appropriate (see Section IV, Considerations for Utility Development and Ownership of Solar for Low-Income Communities), then the utility's program must be designed in a manner that discourages singular treatment not available to the open market. Singular treatment includes access to utility assets, such as customer rolls or the utility bill, or exceptions to rules, such as project size. This does not mean the utility should not utilize assets or seek effective rules, but rather, if the utility finds there is an appropriate way to utilize such assets or improve rules for their own program rollout, they must work to provide appropriate access to the same assets and ensure the same rules apply to other market players. Otherwise, singular treatment creates barriers to community and competitive market involvement in low-income solar, which will ultimately limit program success.

CONCLUSION

The growth of solar in the United States is an opportunity to address challenges such as high energy burdens, unemployment, and pollution in underserved communities. As policy makers, regulators, and advocates work toward expanded solar access and equity, the authors hope that this paper provides assistance in considering the various roles utilities can play to support access to solar for low-income communities and whether regulated utilities should be authorized to own low-income solar projects. The recommendations and considerations highlighted in this paper are intended specifically for low-income solar programs due to distinct barriers to low-income solar deployment. While some of our recommendations may transcend a low-income focus, as a whole, they are not intended to apply to utility involvement in the broader distributed energy resources market. Utilities are in a unique position to directly address some of the barriers to low-income solar deployment and ownership. As such, utilities should be encouraged to break down barriers to low-income solar in ways that prioritize community involvement and local decision-making, support robust competitive market development, and are in the best interests of low-income ratepayers and communities.

APPENDIX A

APPLICATION OF PRINCIPLES AND RECOMMENDATIONS FOR UTILITY PARTICIPATION IN SOLAR PROGRAMS FOR LOW-INCOME CUSTOMERS TO AN EXAMPLE UTILITY PROGRAM: SOUTH CAROLINA ELECTRIC & GAS COMMUNITY SOLAR PROGRAM

In 2014, the South Carolina General Assembly passed, and the Governor signed, legislation to create a Distributed Energy Resources Program. The legislation, commonly referred to as Act 236, opened the door for the utilities in South Carolina to propose community solar programs. In early 2015, South Carolina Electric & Gas ("SCE&G") applied to the South Carolina Public Service Commission for approval to implement its Distributed Energy Resources Program, and proposed a community solar program as a piece of the overall program. The SC PSC approved the program in July 2015.[20]

SCE&G's proposal for its community solar program and special provisions for including low-income customers has been fleshed out since the PSC gave approval. The utility chose to partner with Clean Energy Collective, a company that constructs community solar projects and also develops software for administering community solar subscriptions and bill credits. The 16 MW program is open to residential customers and tax-exempt entities, with 1 MW reserved for low-income households. Customers have the option of purchasing one or more panels, or they can subscribe to the energy output of an array. At this time, all of the low-income subscribers have chosen to subscribe instead of purchase panels. Subscription fees of $0.20 per month per kW and early subscription termination fees are waived for low-income participants. Subscribers earn a monthly bill credit of $0.01 per kWh of energy generated by their share of the community solar project, which, for a 5 kW subscription, would yield a monthly energy output of roughly 600 kWh and thus a bill credit of approximately $6.00 per month. Approximately 200 low-income subscribers are participating in SCE&G's community solar program.

The utility and Clean Energy Collective conducted outreach to community action agencies and the state Office of Economic Opportunity. These entities refer their clients, mainly LIHEAP recipients, to the utility for a quick home energy checkup with some simple energy efficiency measures like LED light bulbs, followed by enrollment in the community solar program.

Here we review SCE&G's low-income community solar offering against the Guidelines for Successful Low-Income Solar Programs in the principal paper (Section V). This review examines SCE&G's low-income community solar offering, not the broader program. While some aspects of SCE&G's low-income community solar offering are beneficial, overall the program falls short of meeting these recommendations.

20 See South Carolina Public Service Commission Docket 2015-54-E for additional information. https://dms.psc.sc.gov/Web/Dockets/Detail/115364

Recommendation	SCE&G's Low-Income Community Solar Offering	Assessment
1. Provide immediate tangible economic benefits for low-income participants.	SCE&G compensates its low-income community solar subscribers $0.01 per kWh generated by the subscriber's share, with no subscription fees. For the purposes of this review, the authors assume an average low-income subscriber's subscription is approximately 5 kW, with a monthly energy output of approximately 600 kWh. This would result in a bill credit of approximately $6.00 per month for an average low-income customer.	**Needs Improvement** In South Carolina, low-income households spend approximately $200 per month on electricity.[21] The energy burden among low-income households in the state ranges from approximately 8% to over 25%,[22] while the national average energy burden is 3.5%.[23] The estimated average bill savings for participating low-income customers will not be enough to meaningfully impact the energy burden, particularly for the most vulnerable customers.
2. Fully compensate low-income solar projects for the services and benefits they provide.	SCE&G owns the community solar projects in its territory. The utility's proposal documents are not clear with regard to the various benefits the company expects.	**Needs Improvement** SCE&G's program could be improved by quantifying benefits such as distribution system modernization and bad debt mitigation.
3. Be designed as replicable, scalable programs for long-term program sustainability and opportunities for adjustment.	SCE&G's low-income offering does not include any steps or opportunities to assess the effectiveness of the program and make adjustments. The term of SCE&G's community solar program is 20 years.	**Does Not Meet the Standard** SCE&G's low-income community solar program could be improved by incorporating regular opportunities for assessment and adjustment to ensure maximum effectiveness.
4. Include long-term funding to support programs, including low-income carveouts for any incentive pools.	The term of SCE&G's community solar program is 20 years. While this may seem like a long-term program, there is no clear plan for continued support for the program.	**Needs Improvement** SCE&G's low-income community solar program could be improved by outlining plans for continued support beyond the planned 20-year program timeline.

21 U.S. Department of Energy, Low-Income Energy Affordability Data (LEAD) Tool, at https://www.energy.gov/eere/slsc/maps/lead-tool.

22 *Id.*

23 Energy Efficiency for All, American Council for an Energy Efficient Economy, Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low-Income and Underserved Communities (2016), at https://catalog.data.gov/dataset/clean-energy-for-low-income-communities-accelerator-energy-data-profiles-2fffb.

Recommendation	SCE&G's Low-Income Community Solar Offering	Assessment
5. Address barriers to participation for low-income households.	Under SCE&G's community solar program, subscription fees of $0.20 per month per kW and early subscription termination fees are waived for low-income participants.	**Meets the Standard** By waiving participation and early termination fees, the SCE&G program addresses basic participation barriers for low-income households.
6. Complement existing programs to reduce overall household energy burden.	As a precondition for participating in the low-income community solar offering, SCE&G requires participating customers to receive a home energy checkup and install some basic energy efficiency measures like LED light bulbs.	**Needs Improvement** While the program involves some basic energy auditing and efficiency measures, deeper energy efficiency and weatherization efforts could further reduce participants' energy burden.
7. Drive local economic opportunity in underserved communities through workforce development and participation for minority- and women-owned business enterprises.	SCE&G's program does not incorporate workforce development opportunities. The company does not appear to have made attempts to solicit the services of women- or minority-owned businesses as program contractors.	**Does Not Meet the Standard** The program does nothing to spur local economic development for underserved communities. The program would benefit from a thoughtful approach to workforce development and soliciting minority- and women-owned businesses to participate.
8. Prioritize community engagement throughout the program design, planning, implementation and ongoing operations, ideally through partnerships with local community organizations.	SCE&G and its contractor Clean Energy Collective conducted education and outreach efforts with community action agencies and the state's Office of Economic Opportunity. These are governmental or quasi-governmental entities. It is not clear that efforts were made to engage directly with community-based organizations.	**Needs Improvement** It is not clear that the utility and its contractor made efforts to engage with underserved communities directly; instead they chose to engage with government or quasi-government agencies that provide social assistance benefits to those communities.
9. In the case of utility-owned projects, treat utility and non-utility owned projects equitably and follow the Considerations for Utility Development and Ownership of Solar for Low-Income Communities.	In South Carolina, non-utility entities cannot offer community solar.	**Does Not Meet the Standard** SCE&G's community solar offering is significantly anti-competitive.

APPENDIX B

APPLICATION OF PRINCIPLES AND RECOMMENDATIONS FOR UTILITY PARTICIPATION IN SOLAR PROGRAMS FOR LOW-INCOME CUSTOMERS TO AN EXAMPLE UTILITY PROPOSAL: CONSOLIDATED EDISON COMPANY OF NEW YORK'S SHARED SOLAR PILOT PROGRAM

In July 2015, New York's Department of Public Service (the "Commission") issued an Order establishing a Community Distributed Generation (CDG) program as part of the state's effort to transition from net metering to a Value of Distributed Energy Resources (VDER).[24] New York recognized that "broad community participation in DG is envisioned in the Reforming the Energy Vision (REV) proceeding." CDG was largely seen as a way to expand access to those that cannot access on-site solar.

The state's CDG market took a significant amount of time to develop. New York entered a complex VDER proceeding to quantify the temporal and location values of DERs. The Commission also took time to look into CDG projects for low-income households in New York, including the role of utilities in the CDG space. Market uncertainty, particularly around the value of CDG projects, essentially stalled project development in the state.

Therefore, it came as a surprise when Consolidated Edison Company of New York, Inc. (ConEd) filed a Petition for Approval of a Pilot Program for Providing Shared Solar to Low-Income Customers in October, 2016. The ConEd pilot consisted of a 3MW utility-owned community solar facility dedicated to serving low-income households already participating in the utility's electric low-income affordability program.

ConEd's proposal presents an interesting case study. New York state is a restructured market where electric distribution companies, like ConEd, are not permitted to own generation or distributed energy resources. The utility justified its Petition by saying that the CDG program was falling short of serving low-income customers and that this customer segment is underserved by the marketplace.[25] Their claim of a market failure was considered premature by several intervening parties. New York's CDG market was essentially stalled because of the state's ongoing Value of Distributed Energy Resources proceeding. Therefore, CDG projects were essentially unfinanceable because of regulatory uncertainty associated with the value of the energy they would generate. Furthermore, the Petition was submitted before Commission Staff completed their white paper on utility ownership of community distributed generation projects that expand access to low and moderate income participation. ConEd was also separately exploring non-utility owned, market based solutions to serve LMI customers in a Request for Information (RFI) that was still open at the time.

Nonetheless, the Commission approved the pilot in August, 2017, allowing Phase 1 of ConEd's pilot to proceed as a demonstration project serving low-income households, thus creating an exception to the general rule that utility ownership of DERs is not allowed. The Order approving the program explicitly stated that the pilot will "[offer] the state and market participants the opportunity to gain experience with a new model for providing low-income customers with access to DERs."[26] As of May 2019, the project design is still being finalized.[27]

This review primarily examines ConEd's proposal against the Guidelines for Successful Low-Income Solar Programs outlined in the principal paper (Section V):

24 http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={76520435-25ED-4B84-847
25 http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-E-0622&submit=Search
26 New York State Department of Public Service (2017). Order Approving Shared Solar Pilot Program with Modification. Case Number 16-E-0622. Retrieved from http://www.dps.ny.gov/.
27 http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-E-0622&submit=Search

While some aspects of ConEd's proposal are beneficial, overall the proposal falls short of meeting those recommendations. In addition, the premature finding of market failure in approving the program highlights the issues raised in our Considerations for Utility Development and Ownership of Solar for Low-Income Communities (Section IV).

Recommendation	ConEd's Pilot Proposal	Assessment
1. Provide immediate tangible economic benefits for low-income participants.	According to ConEd's proposal, 100% of the 3 MW system will be dedicated to low-income subscribers. The value to subscribers is guaranteed to be either "positive or zero", with households expected to save approximately $5 per month. The company is achieving economies of scale with a 3MW system installed on utility-owned property, which has the added benefit of reducing overall project development costs.	**Needs Improvement** In the state of New York, low-income households spend an average of approximately $100 per month on electricity.[28] The energy burden among low-income households in the state ranges from approximately 6% to 17%,[29] while the national average energy burden is 3.5%.[30] A $5 per month credit is low and fails to provide meaningful savings for low-income households participating in the program. ConEd was asked to examine strategies to increase the level of savings, including greater participant benefits through ancillary offerings such as energy efficiency, home weatherization, and third party DER offerings paired with participation. It is also possible that ConEd will improve the customer value proposition but that is unknown at this time.
2. Fully compensate low-income solar projects for the services and benefits they provide.	The Company plans to prioritize installation in areas where additional DER penetration "may benefit the system and other customers through a reduced need for traditional infrastructure investments". However, the actual credit rate is set to the value of output of solar generation set in the VDER proceeding minus the estimated costs of the pilot.	**Meets the Standard** New York's Value of Distributed Energy Resources (VDER) proceeding attempts to capture the locational and temporal values of distributed generation. The robust valuation methodology recognizes that solar resources provide benefits to the distribution system. It also captures the environmental benefits of solar generation.

28 U.S. Department of Energy, Low-Income Energy Affordability Data (LEAD) Tool, at https://www.energy.gov/eere/slsc/maps/lead-tool.

29 *Id.*

30 Energy Efficiency for All, American Council for an Energy Efficient Economy, Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low-Income and Underserved Communities (2016), at https://catalog.data.gov/dataset/clean-energy-for-low-income-communities-accelerator-energy-data-profiles-2fffb.

Recommendation	ConEd's Pilot Proposal	Assessment
3. Be designed as replicable, scalable programs for long-term program sustainability and opportunities for adjustment.	The petition only mentions an evaluation framework that provides data on the overall program operation, including aggregated data on participating customer accounts. However, it is unclear how that evaluation framework will be used to make adjustments to Phase 2 of the pilot. Third-party entities were only able to participate via competitive procurement for the design, siting, permitting and construction of the facility.	**Needs Improvement** ConEd's proposal could be improved by incorporating regular opportunities for assessment, stakeholder feedback and adjustment before Phase 2 to ensure maximum benefits for participating households. ConEd's proposal could also be improved with annual reporting requirements, a stakeholder process to guide program review and adjustment, and opportunities to maximize competitive market-based offerings for the Company's low-income ratepayers. Lastly, ConEd operates in a restructured market and moved forward with their Petition without proof of a market failure. Therefore, to design this program with an eye toward long-term sustainability the Petition should have discussed how ConEd would transition away from ownership to a facilitator role, be a backstop to increase project financeability of low-income projects, and generally move toward competitive market-based offerings.
4. Include long-term funding to support programs, including low-income carveouts for any incentive pools.	ConEd proposed to own and operate the solar facility as part of a Pilot Program. The utility does not have plans to replicate the Pilot at this initial stage and did not secure long-term funding to support a scalable utility-owned low-income program. The 3 MW utility-owned system is expected to cost $9-million. The Shared Solar Pilot funding is incremental to the Company's current electric revenue requirement will be recovered from customers.	**Needs Improvement** ConEd's program is an initial Pilot Program offering. The utility has plans to expand the program to 11 MW should the initial 3 MW phase be successful. As the Pilot current stands, it is a stop and start program that will create uncertainty among consumers and market participants and fails to provide a sustainable funding source.
5. Address barriers to participation for low-income households.	ConEd's Pilot program removes several barriers for low-income household participation, including the cost of any upfront payment and credit checks, both of which could limit participation.	**Meets the Standard** ConEd's Pilot successfully addresses basic participation barriers for low-income households by eliminating upfront costs and credit checks.

Recommendation	ConEd's Pilot Proposal	Assessment
6. Complement existing programs to reduce overall household energy burden.	Eligible customers are those that are already qualified to participate in the company's low-income affordability program and the no-cost, energy efficiency program offered by the utility or state agency. The petition states that the pilot will provide additional benefits, such as increased energy literacy and awareness and greater participation in energy efficiency programs.	**Meets the Standard** Using an existing low-income affordability program means that the company can easily identify income-eligible candidates to participate in the program. In addition, these are households that have received energy efficiency upgrades. When combined with a community solar subscription, energy efficiency plus solar can effectively reduce a household's energy burden.
7. Drive local economic opportunity in underserved communities through workforce development and participation for minority- and women-owned business enterprises.	ConEd's materials do not mention an intention to utilize local vendors, nor does the proposal include any consideration or provision of job training for individuals in underserved communities.	**Needs Improvement** ConEd could strengthen its program by using local vendors and providing on-the-job training opportunities.
8. Prioritize community engagement throughout the program design, planning, implementation and ongoing operations, ideally through partnerships with local community organizations.	ConEd's petition only included a brief reference to a marketing and outreach strategy that includes engagement with community organizations. However, that is expected after the program design phase rather than any meaningful community engagement throughout the program design and planning process. The company issued an RFI from community organizations for local outreach and marketing of ConEd's Shared Solar program,indicating a desire to select one community partner in each Shared Solar neighborhood to facilitate community engagement, education and outreach.	**Needs Improvement** ConEd's proposal could be improved by demonstrating a clear dedication to community engagement. The utility should have created a stakeholder process in the design of the pilot to ensure community needs and desires are met with such a unique utility-owned program. The issuance of an RFI appears to be a step in the right direction.

Recommendation	ConEd's Pilot Proposal	Assessment
9. In the case of utility-owned projects, treat utility and non-utility owned projects equitably and follow the Considerations for Utility Development and Ownership of Solar for Low-Income Communities.	ConEd's program utilizes competitive bidding for its 3 MW CDG project. The petition states that the pilot will not replace or compete with projects that would be proposed by third parties under the utility's Low-and-Moderate Income Demonstration Project. ConEd's proposal includes a plan for including its project subscribers in an on-bill financing program, which would not be made available to other providers. The utility's petition failed to acknowledge the competitive advantage the utility has within the broader NY CDG program or to recognize that the utility was moving forward with its pilot before the market could provide adequate certainty for third-party owned systems.	**Needs Improvement** ConEd's proposal is significantly anti-competitive. The utility's proposal would be improved by ensuring that on-bill financing was afforded to market participants and that the market had a chance to develop third-party focused low-income solutions. In their proposal, the company could also have articulated measures they could undertake to prevent a competitive advantage over other third party community solar offerings. Furthermore, ConEd should have waited to submit its petition until after: • The VDER proceeding was completed and tariff structures put in place; • Commission staff received input on the role of utility sponsored CDG projects; and, • Commission staff finalized their white paper relating to CDG for low-income customers.

Rakon Report

2021

A report focusing on High Distributed Solar in Xcel Energy Supplemental IRP

FOR VOTE SOLAR, INSTITUTE FOR LOCAL SELF-RELIANCE, AND COOPERATIVE ENERGY FUTURES

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Rakon Energy LLC

Rakon Energy LLC report for Vote Solar, Institute for Local Self-Reliance, and Cooperative Energy Futures

focusing on High Distributed Solar in

Xcel Energy's Supplemental Integrated Resource Plan (IRP)

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I. Executive Summary

Vote Solar, Institute for Local Self-Reliance, and Cooperative Energy Futures retained Rakon Energy LLC to review Northern States Power (NSP) – Minnesota's (doing business as Xcel Energy) High Distributed Solar (HDS) modeling included in the company's June 30, 2020, Supplement to its 2020-2034 Upper Midwest Integrated Resource Plan in Docket Number E002/RP-19-368 (IRP). I reach several conclusions:

First, NSP must improve its planning to include additional distributed resources and treat them as a "central element to the utility's optimized plan." In fact, due to market changes, technology development, and federal policy including FERC Order 2222, it is inevitable that greater distributed resource development will occur and will need to be accommodated by NSP plans. Planning for greater distributed resource penetration at this stage would allow efficient resource optimization rather than inefficient after-the-fact adjustments to the Company's resource plans.

Second, distributed resources interconnected to Xcel's distribution system avoid the MISO queue process that is currently backed up by more than a few years and which neither the Commission nor Xcel can control. Emphasizing distributed resources allows Xcel to integrate higher levels of renewable resources than by focusing on utility scale, transmission-interconnected, generation that must navigate the MISO interconnection queue.

Third, MISO is currently modeling more than 3,000 MW of DG PV in 2021 transmission planning models. Those model runs demonstrate that a much higher level of distributed solar can be economically added to the system than Xcel is currently planning. That further confirms that NSP should revise and extend its assumptions beyond the level of distributed generation in its HDS sensitivity to determine transmission and distribution needs now.

Fourth, distributed solar, especially distribution connected DG within the Twin Cities Metro Area should have a higher Effective Load Carrying Capability than utility scale solar connected at transmission to remote nodes. Differences in the ELCC of resources has been shown to vary by interconnection node. Xcel and MISO should jointly determine the capacity value of distributed resources through a locational capacity value ELCC.

Lastly, this report points out that that distribution connected solar avoids distribution and transmission system costs in addition to providing resource benefits. Aligning distribution, transmission, and resource planning will reveal currently unrealized value. The Commission should require Xcel to integrate distribution, transmission, and resources as part of its IRP to meet system's reliability needs most effectively, rather than through balkanized planning. High density distributed resources will produce higher locational capacity in and around the Twin Cities Metro Area and should be considered separately from other portions of NSP's service territory.

II. High Distributed Solar (HDS) Modeling

A. NSP's Supplemental IRP modeled a "high distributed energy future" (High Distributed Solar or HDS) and expresses various concerns regarding high levels of distributed energy. NSP's HDS modeling contains certain flaws and NSP's concerns are overstated.

NSP should have assumed a higher level of baseline distributed resources and then modeled several additional levels of HDS to account for increments of distributed energy that NSP can achieve beyond the baseline level.

1. NSP's Assumed Baseline Distributed Resource Level is not realistic when compared to MISO MTEP Futures

NSP's Supplement IRP does model HDS as one of the "futures sensitivity" cases. However, because those model runs also assumed lower load forecasts, they ultimately produce lower capacity selection for HDS[1]. NSP did not accurately model incremental distributed resources as available capacity expansion options for selection when optimizing. According to the Supplemental IRP ("SIRP"), NSP "continues to use" its historic practice of adjusting load forecasts for energy efficiency, demand response and distributed generation "to estimate our net energy and load into the future" while also "test[ing] the economic impact of including various 'bundles' of EE and DR… to allow those resources to compete with traditional supply-side resources…" SIRP at p 19 of 78. Thus, the company assumes a baseline level of efficiency and demand response and then makes additional "bundles" available for the model to select. Distributed generation is

[1] SUPPLEMENT 2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN DOCKET NO. E002/RP-19-368, Page 38 of 78.

notably treated differently. The company does not make additional "bundles" or increments of distributed generation available for selection by the model. Instead, the company's modeling assumes a declining level of "Solar*Rewards" generation and a moderate to low level of "Community Solar" and "Distributed Solar" between 2020 and 2034. Those categories, combined, start at 366 MW in 2020 and end in 2034 at 340 MW. SIRP page 25 of 78, Table 2-2. That is, the company's baseline assumption is that total existing distributed generation resources actually decline during the planning period before a moderate amount of new distributed solar is forced into its expansion plans starting at 173 MW in 2020 and quickly declining to 16 MW in 2025 and then 15 MW annually 2026-2034. SIRP p 73, Table 3-1.

NSP's modeling did test the "sensitivity" of its plans to a higher level of distributed generation. However, it did not allow the model to select additional distributed generation as a resource as part of an optimized expansion plan. It also assumed that high distributed solar always occurs together with lower load growth. But Xcel did not test higher levels of distributed solar and higher levels of electrification and load growth together. SIRP at 35.

2. Xcel's concern about solar dispatchability can be offset by MISO operator

The Supplemental IRP expresses a fundamental desire by NSP to be able to meet peak demand without relying on intermittent resources or market purchases.[2]

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[2] SIRP Page 41 of 78, Table 2-5: Scenario Modeling Portfolio Scorecard, "Reliability" ("Evaluates the share of peak load that we are able to serve without relying on NSP system use limited and variable resources, or off-system market energy and capacity purchases. This measure helps us identify market exposure in the event variable and use-limited resources are unavailable for a period of time.")

There are several problems with that criteria. First, contrary to NSP's description of it solar dispatchability as a "Reliability" concern, it is a financial concern. There is no reduction in reliability by relying on the market for energy or capacity. There is a potential cost, or financial risk, of doing so. But that is a financial consideration not a reliability consideration.

Second, the variability of resources does not mean that they should all be assumed unavailable at the time of system peak, which is what NSP's "Firm Dispatchable Resource to Peak Load Ratio" effectively does. Instead, NSP should utilize an analysis intended to account for variable resources. FERC approved MISO's treatment of solar as a Dispatchable Intermittent Resource (DIR)[3] and application of the Security Constrained Economic Dispatch (SCED) algorithm. As a DIR, HDS must submit a Day-Ahead forecast to MISO, but it is not financially binding due to solar forecasts' intermittent nature.

> "*For reliability purposes, each Intermittent Resource and Dispatchable Intermittent Resource must submit to the Transmission Provider a Day-Ahead forecast of its intended output for the next day consistent with the procedures for such forecast set forth in the Business Practices Manuals.* ***The Day-Ahead forecast shall not be financially binding on the Resource***.[4]"

As a qualified capacity resource in the MISO market, the MISO SCED and control room operator ultimately decide to dispatch a unit.

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[3] FERC approval of MISO's Solar DIR filing, https://cdn.misoenergy.org/2020-06-09%20171%20FERC%20%C2%B6%2061,203%20Docket%20No.%20ER20-595-000;%20-001452020.pdf

[4] Ibid, Requirement of Day-Ahead Forecast

Additionally, **dispatching distributed solar in MISO planning models is inevitable** because of 3,000 MWs plus DG PV capacity forecasted[5], which is an input into MISO transmission needs assessment. Hence it is recommended that NSP incorporate HDS in MISO capacity auction and leave the dispatch of HDS to MISO SCED and operator decision.

B. FERC Order 2222 requires Xcel and MISO to accept HDS as a market resource

NSP's failure to account for significantly more distributed generation in its baseline is inconsistent with the likely impacts of FERC Order 2222 on DER Aggregation (DERA). Order 2222 requires MISO to accept aggregated and individual DERs as wholesale market resources. As a distribution utility, Xcel must coordinate with both the HDS owner and MISO.

Xcel must figure out how to dispatch and coordinate with HDS to comply with FERC Order 2222. And Xcel's North American Electric Reliability Corporation (NERC) compliance obligations are tied to MISO's for the dispatch of distributed solar in the planning models. So, to comply with both upcoming FERC regulations on DERs and existing NERC planning regulations, Xcel must address HDS dispatch.

C. Distributed Generation Avoids Transmission Interconnection Limitations

The Supplemental IRP refers to currently backlogged transmission interconnection queues as a reason for limiting new renewable generation.

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[5] MISO Planning Advisory Committee October 14, 2020, agenda item 3a, MTEP21 Futures Resource Expansion and Siting Results, slide 3 of 9, https://cdn.misoenergy.org/20201014%20PAC%20Item%2003a%20MTEP21%20Futures%20Resource%20Expansion%20and%20Siting%20Results482500.pdf

However, MISO allows Xcel to register distributed resources as capacity resources. Doing so avoids transmission interconnection issues.

1. <u>MISO Deliverability Study ensures HDS is available for the entire MISO load</u>

Distributed generation can count towards a Load Serving Entity's (LSE) resource adequacy requirements when deemed deliverable by MISO. Part of MISO's deliverability determination depends on whether there are transmission constraints that restrict a network resource's output. Alternatively, generation interconnected at the distribution level effectively provides capacity by reducing Xcel's peak load contribution to MISO's Planning Reserve Margin Requirement (PRMR), in turn reducing Xcel's capacity obligations at MISO.

Hypothetically, if Xcel has a 10,000 MW peak load and MISO's Unforced Capacity (UCAP) PRMR is 3.46 % - Xcel has a 10,346 MW capacity obligation. However, if 1,000 MW of distributed solar is interconnected to the Twin Cities Metro Area (TCMA) distribution system, Xcel's peak load is reduced to 9,000 MW. And Xcel only has a 9,311 MW capacity obligation assuming the same UCAP PRMR. That is, distributed resources have a greater than 1:1 capacity value and can avoid transmission interconnection delays and costs.

FERC Order 2222 allows HDS aggregation by Xcel as the distribution utility and coordinate with MISO as the transmission provider. The transmission facility where the HDS interconnects to the MISO system would be under MISO's functional control.

2. HDS capacity obligation reduction benefit

To quantify the capacity obligation reduction value in resource planning models, the difference in NSP obligation of 1,000 MW is worth at least $1.825 million per year in MISO capacity costs[6].

As part of the Planning Resource Auction (PRA) at MISO, which FERC approved, MISO LSEs have the option to point to resources approved in a state Integrated Resource Plan (IRP) to meet their PRMR. This option is called Fixed Resource Adequacy Plan FRAP[7].

Xcel is part of Local Resource Zone 1 at MISO. MISO's 2020/21 PRA includes 20,296 MW offered, and 14,198 MW of FRAP cleared in zone 1[8]. So, 70% of the offered FRAP capacity cleared in the 2020 MISO auction. Hence FRAP is common at MISO. And across MISO, 850 MW of solar cleared[9] in the 2020/21 PRA, increasing 25% relative to last year's auction.

3. HDS as a resource in FRAP must offer into MISO energy market

There is also a MISO market requirement for solar capacity resources cleared in the planning resource auction to participate in the Day-Ahead Market (DAM) called "must offer."

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[6] Slide 5 of MISO Planning Year 2020/21 auction shows $5 per MW-day which translates into $5,000 per day multiplied with 365 days in a year equals $1.825 million per year, https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf

[7] MISO Resource Adequacy Business Practice Manual BPM-011-r23 Effective Date: March-31-2020, section 5.3 – Fixed Resource Adequacy Plan, page 89 of 183

[8] MISO 2020/21 PRA results, 04/14/2020: MISO Planning Resource Auction (PRA) for Planning Year 2020-2021 Results Posting, slide 7 of 17, https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf

[9] Ibid, slide 11 of 17.

> *"an MP that owns a Capacity Resource that has ZRCs identified as part of a **Fixed Resource Adequacy Plan** or ZRCs which clear in an annual or Transitional PRA **must submit** the ICAP equivalent MW value of the cleared ZRCs into the **Day-Ahead Energy Market**, and each pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment (RAC) for every hour of every day, except to the extent that the Intermittent Resource is unavailable due to a full or partial scheduled outage[10]"*

So, HDS can qualify as a capacity resource, and if cleared in the MISO PRA, has a must offer requirement in the MISO Day Ahead energy markets. The must offer requirement applies for all Dispatchable Intermittent Resources[11], which includes solar now due to FERC acceptance of MISO's DIR filing. **Hence HDS can participate in MISO capacity markets as a FRAP resource.**

D. Energy price (LMP) arbitrage opportunities with HDS

1. Xcel ignores the Locational Marginal Price (LMP) benefits of HDS.

Locational Marginal Price (LMP) is the sum of the marginal price of meeting the next MW of energy, transmission congestion, and transmission losses. This energy price is calculated at each Generation Elemental Pricing EPNode[12] on the

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[10] Section 4.2.3.6. Intermittent Resource Generation and Dispatchable Intermittent Resources – Must Offer, MISO BPM 011 – Resource Adequacy, Revision 15, Effective date of March 31, 2020. https://www.misoenergy.org/legal/business-practice-manuals/

[11] Ibid, "The must offer requirement applies to the Installed Capacity of the Intermittent Generation and Dispatchable Intermittent Resources, and not to the UCAP rating."

[12] Section 4.1, Elemental Pricing Nodes (EPNodes), MISO Network and Commercial Models Business Practices Manual (BPM), BPM 010 Revision 12

electric system inside the MISO market. If solar is located at an EPNode, this LMP is the price paid to the solar by the MISO market for serving the market load.

Xcel's supplemental IRP discusses MISO LMP in 2 areas: 1) its discussion of reliability, as a hedge against LMP price spikes when referring to firm dispatchable resource-to-peak load ratios in 2034[13], and 2) in its discussion of market sensitivities, to justify an adder for carbon[14]. **But Xcel's supplemental IRP does not consider the LMP benefits of HDS.**

Historical LMPs show where it would be worth locating market resources, either the supply side or demand side. If we look at the congestion component alone, market nodes with higher LMPs indicate a need for new transmission or alternatives to transmission solutions. And if we look at the transmission loss component alone, market nodes with higher prices indicate where HDS would benefit from reducing the transmission loss component.

Energy price arbitrage refers to buying energy at off-peak prices and selling energy at peak prices. If MISO dispatches Xcel HDS generation, Xcel Generation Elemental Pricing Node ("EPNode") receives the market-clearing price at that hour. During peak hours, this market price can be higher (generally in the order of hundreds of dollars per MWh) relative to off-peak hour prices (generally in tens of dollars per MWh). At a MISO market EPNode with HDS, Xcel can charge a battery

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[13] SUPPLEMENT 2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN DOCKET NO. E002/RP-19-368, Page 50 of 78, right before the Figure 2-20: Firm Dispatchable Resource-to-Peak Load Ratios in 2034, "we are hedged during periods of extreme MISO market demand and/or locational marginal price (LMP) spikes."

[14] Attachment A: Supplement Details, Page 135 of 176, "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".

with solar energy obtained at off-peak pricing[15] and discharge the battery energy at peak. Xcel's ratepayers stand to benefit from energy price arbitrage because shifting stored solar energy (without fuel costs) from off-peak to peak hours results in less need to turn on fossil fuel units with fuel costs for the evening ramp.

LMP arbitrage opportunities occur at the Generation Elemental Pricing Nodes (as mentioned earlier), which are aggregated at Generation Commercial Pricing nodes (CPNode) or "Gennode" for short, on the MISO system. Xcel's supplemental IRP includes analysis of MISO market sales at the Generator pricing nodes as indicated in the Vote Solar, Institute for Local Self-Reliance, and Cooperative Energy Futures, Information Request No. 5[16] ("19-0368 VS ILSR CEF-005"). So, Xcel should investigate the LMP benefits of HDS.

It is worth noting that when discussing the nuclear update in section VIII, Xcel mentions the MISO Day Ahead Market to make a finer point[17] about ramping down nuclear units to accommodate more renewables on the grid. Hence, Xcel considers MISO market opportunities for certain resources in this resource plan. It

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[15] From Xcel Integrated Distribution Plan – Annual Update, Attachment A – Page 4 of 26, "Minimum solar output curves utilized during the analyses ranged from 24-36% of peak output from 10AM to 4PM and to percentages less than that outside of that timeframe."

[16] Data Request Response 19-0368 VS ILSR CEF-005, "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. In the Encompass modeling, market sales were limited to 25 percent of retail load in the capacity expansion runs in order to limit sales risk exposure"

[17] Attachment A: Supplement Details, Page 121 of 176, "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".

is therefore reasonable for Xcel's plan to consider similar MISO market opportunities for HDS.

2. Leveraging battery storage for energy price arbitrage in MISO is a proven concept, and MISO has experience with market participation by storage resources as well as storage dispatch.

FERC Order 841 mandates that each ISO shall have a market participation model for electric storage resources. Batteries can participate in the MISO market by registering as a Stored Energy Resource (SER) Type II[18]. In fact, Xcel has experience with a battery resource participating in the MISO market as Stored Energy Resource (SER). Xcel's 5MWh battery project at Luverne, Minnesota is an SER in the MISO market participation model. As an SER, Xcel's battery can provide regulating reserves in MISO's ancillary services market. And with an SER Type II category[19], Xcel's battery can provide capacity, energy, and other ancillary services such as spinning, supplemental and ramping services.

In addition to the existing Luverne battery, Xcel has 270 MW[20] of battery storage in the "active" study status of the MISO generator interconnection queue as of December 2020. For a 100 MW request (J1468) storage project waiting to be

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[18] FERC Docket # ER19-465, November 1, 2019, ""MISO notes that the requested deferred implementation of the ESR participation model is expected to have limited impacts on the ability of storage-type resources to participate in MISO's markets. While MISO recognizes there are storage-type Resources in MISO's current Generation Interconnection queue, it maintains that any storage-type Resources that emerge from the interconnection queue and actually enter into service before June 2022 can participate in MISO's markets as Stored Energy Resources – Type II ("SER-Type II")."

[19] FERC Docket # ER19-465, MISO filed on December 3, 2018 – MISO Compliance Plan for FERC Order 841, https://elibrary.ferc.gov/eLibrary/search

[20] MISO Queue, https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/gi-interactive-queue/# , project numbers are J1045, J1468, J1494, J1495, and J1498.

interconnected at the Xcel transmission substation, the earliest date for Generator Interconnection Application (GIA) execution is August 2022. That timeframe misses the deadline for the MISO planning resource auction in April 2022. Therefore, instead of depending on the MISO queue (which is lengthy and outside Xcel's control), Xcel has a much better chance of interconnecting HDS with storage to participate in MISO markets leveraging its Luverne battery experience.

Moreover, MISO has experience with market participation by storage technologies, as well as storage dispatch. The Ludington pumped storage units located in Michigan and jointly owned by Consumers Energy and DTE Energy, for example, participate in MISO markets for energy price arbitrage. During night time, i.e., the off-peak time, the Ludington units charge by pumping water up the reservoir. During day time, i.e., the peak time, the Ludington units discharge the stored water to run the electric generator[21].

3. Xcel must examine the locational aspects of HDS, including transmission and distribution system benefits, in this IRP

Xcel did not examine transmission or distribution system benefits to evaluate the energy market feasibility of an HDS future. [22] In response to a data request on this subject, Xcel stated that:

"our Integrated Resource Planning process is primarily focused on size, type, and timing of potential future resource additions. As such, ***we do not***

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[21] MISO Market SubCommittee August 21, 2018 Pumped Storage presentation, https://cdn.misoenergy.org/20180821%20Order%20841%20Workshop%20Item%2002%20Pumped%20Storage268634.pdf

[22] Data Request Response 19-0368 VS ILSR CEF-003

> ***examine locational aspects of specific distributed resource additions** in the IRP"*

But Xcel's supplemental IRP takes into accounts the locational value of wind:

> *"We note that we have shifted from using the MISO footprint average wind ELCC of 15.6 percent to the most recent Zone 1 specific ELCC of 16.7 percent, in order to better capture the higher locational value of wind resources in our specific region[23]"*

Hence it reasonable to expect Xcel to model HDS accurately to assess locational impacts of HDS, including transmission and distribution system benefits.

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To summarize, HDS (particularly HDS located inside the TCMA) provides a hedge against LMP price spikes. Xcel should leverage its experience with Luverne battery storage participation in the MISO market and reflect the energy price arbitrage opportunities associated with HDS in its IRP.

E. Inside Twin Cities Metro Area

This report recommends that Xcel quantify the capacity value of locating distributed solar inside the 4 county "Twin Cities Metro Area" within Xcel's service area because HDS will be located closer to NSP's substations where peak demand occurs.

[23] Supplemental IRP footnote 14, page 22 of 78

For this report, the Twin Cities Metro Area (TCMA) is defined as Xcel's service area in the Minnesota Electric Transmission Planning Twin Cities Zone[24] (which Xcel referenced in data request 19-0368 VS ILSR CEF-004). According to the Minnesota Electric Transmission Planning website, eight Minnesota counties – Anoka, Carver, Chisago, Dakota, Hennepin, Ramsey, Scott, and Washington- are in the Twin Cities Zone. Xcel's substations in Dakota, Hennepin, Ramsey, and Washington are inside the TCMA as shown in Figure 1, and Xcel's substations in Anoka, Carver, Chisago, and Scott counties are outside the TCMA.

According to the Minnesota State Demographic Center data[25], in 2019, Minnesota's population was greater than 6 million. More than 3.2 million people

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[24] Minnesota Transmission Planning zones are shown here: http://www.minnelectrans.com/minnesota-zones.html

[25] Downloaded data titled, Latest annual estimates of Minnesota and its 87 counties' population and households, 2019. (Excel file, released August 2020.) from Our Estimates / MN State Demographic Center

live in the eight-county Twin Cities Zone, and of that population, 2.5 million reside in the TCMA as defined in this report.

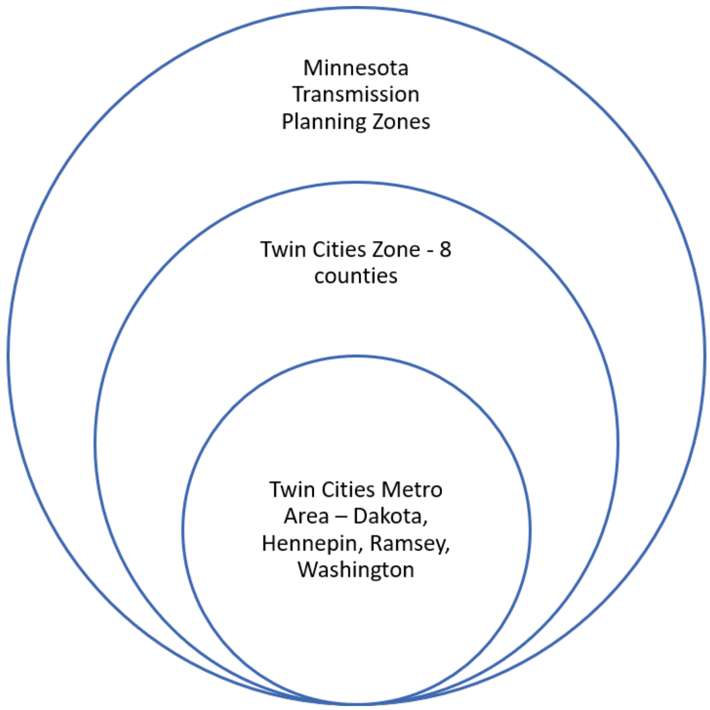

Figure 1: TCMA Definition Illustration

Xcel serves customers in the TCMA and outside the TCMA but within the Twin Cities Zone. In this section of this report, we focus on the TCMA because the TCMA includes several major Xcel substations (such as Merriam Park, Saint Louis Park, Edina, East Bloomington, Woodbury, Eden Prairie, and West Coon Rapids) and because from a transmission planning perspective, Xcel is planning at the Twin Cities zonal level.

1. A portion of the 995 MW of HDS potential in Xcel's service area can be interconnected to Xcel's distribution system ahead of MISO's April 2022 planning auction.

The capacity contribution of HDS cannot be overstated for Xcel because the MISO capacity auction includes provisions for Xcel's IRP capacity. More than 70% of IRP capacity cleared in MISO's latest auction[26]. HDS can be a part of the MISO auction's capacity as early as December 2021, in preparation for the April 2022 MISO auction.

Compared to the 1937 MW of solar shown in Table 1 waiting to be studied[27] by MISO in their generator interconnection queue (at Xcel's transmission substations), interconnecting 995 MW[28] of HDS potential at Xcel's distribution substations is entirely within Xcel's control[29].

Most of Xcel's 1937 MW in the MISO queue may see a study report in the next 2 years, around July 2022, with a potential agreement execution in March 2023[30]. That 3-year delay will miss the window for MISO's planning year 2022/23 and possibly 2023/24. In contrast, some of the 995 MW of HDS potential can be distribution interconnected as soon as December 2021 in time for MISO's planning auction in April 2022.

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[26] Slide 7, 2020/21 PRA Results by Zone shows 14,000 MW of FRAP cleared in Zone 1 out of the 20,000 MW offered. https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf

[27] MISO Generator Queue, filtered for solar fuel type, "Active" study status and Northern States Power (Xcel Energy) Transmission Owner in Minnesota.

[28] From Xcel's 2020 hosting capacity analysis (DISTRIBUTION SYSTEM – HOSTING CAPACITY ANALYSIS REPORT, Docket No. E002/M-19-685).

[29] Search for docket #, RM18-9, and filed date of October 07, 2019 in this FERC eLibrary, https://elibrary.ferc.gov/idmws/search/fercgensearch.asp "DERs typically connect to distribution facilities and are subject to the rules of the directly connected local distribution provider ("Host Distribution Provider") rather than the MISO Tariff. MISO's historic involvement with distribution-level interconnections largely has been limited to coordinating with the Host Distribution Provider where MISO is identified as an affected system."

[30] MISO Queue timeline - https://cdn.misoenergy.org//Definitive%20Planning%20Phase%20Schedule106547.pdf

Table 1: Total amount of solar waiting to be interconnected at Xcel's substations (Source: MISO queue, Jan 2021)

	Request S	Queue Date	Appl In Servi	County	Study Cycle	Study Gro	Study Phase	Service Ty	Summer N
J1001	Active	3/12/2018	9/1/2020	Lincoln County	DPP-2018-APR	West	PHASE 2	NRIS	40
J1072	Active	3/12/2018	9/1/2020	Mower County	DPP-2018-APR	West	PHASE 2	NRIS	150
J1098	Active	3/12/2018	9/30/2022	Jackson County	DPP-2018-APR	West	PHASE 2	NRIS	40
J1105	Active	3/12/2018	9/1/2020	Dakota County	DPP-2018-APR	West	PHASE 2	NRIS	200
J1212	Active	4/27/2019	10/31/2023	Murray County	DPP-2019-Cycle	West	PHASE 1	NRIS	60
J1337	Active	4/29/2019	6/30/2022	Sherburne County	DPP-2019-Cycle	West	PHASE 1	NRIS	300
J1445	Active	4/29/2019	8/1/2022	Benton County	DPP-2019-Cycle	West	PHASE 1	NRIS	100
J1446	Active	4/29/2019	8/1/2022	Wright County	DPP-2019-Cycle	West	PHASE 1	NRIS	150
J1461	Active	4/29/2019	8/1/2022	Carver County	DPP-2019-Cycle	West	PHASE 1	NRIS	50
J1473	Active	4/29/2019	8/1/2022	Chisago County	DPP-2019-Cycle	West	PHASE 1	NRIS	100
J1581	Active	7/10/2020	9/1/2023	Nobles	DPP-2020-Cycle	West	Study Not Started	NRIS	200
J1605	Active	7/10/2020	9/1/2023	Sherburne	DPP-2020-Cycle	West	Study Not Started	NRIS	200
J1620	Active	7/13/2020	9/1/2023	Pipestone	DPP-2020-Cycle	West	Study Not Started	NRIS	125
J803	Active	6/16/2017	10/1/2019	Lyon County	DPP-2017-AUG	West	PHASE 2	ERIS	32.5
J874	Active	6/16/2017	9/30/2021	Murray County	DPP-2017-AUG	West	PHASE 2	NRIS	150
J905	Active	6/16/2017	9/15/2020	Pipestone County	DPP-2017-AUG	West	PHASE 2	NRIS	40
									1937

As discussed in the earlier section of this report, for resources inside the TCMA, once qualified by MISO as a capacity resource, Xcel can meet its capacity obligations as a Load Serving Entity (LSE) addressing the Planning Reserve Margin Requirement (PRMR) of MISO.

In summary, given Xcel's stated concerns regarding capacity needs, it may realize a capacity benefit from siting HDS inside the TCMA and participating in MISO's planning auction via FRAP indicated in the MISO's latest auction, which cleared 850 MW of solar.

2. Reliability benefits of HDS in the TCMA

In addition to the capacity benefits that HDS provides, HDS resources around the TCMA can provide reliability to meet the NERC resource assessment criteria (BAL-502-RF-03) of 1 day in 10 years. All else equal, smaller and multiple units provide better reliability when compared to single units with a larger capacity. For example, ten 1 MW units provide better reliability than a single 10 MW unit—a system with ten 1 MW units translates into 0.1 days per year, and hypothetically, a power system with a single 10 MW unit would have a higher than 0.1 Loss of Load Expectation (LOLE).

One way to look at the reliability benefits of HDS is through Xcel's hosting capacity analysis. Does any given substation have enough capacity for the interconnection of the distributed solar? For each substation inside the TCMA, the answer to that question appears to be yes (see **Error! Reference source not found.** below).

As Table 2 demonstrates, there is a potential 995 MW of hosting capacity available for HDS within the TCMA. If 995 MW of HDS were interconnected to Xcel's distribution system inside the TCMA, it would provide reliability benefits to the grid.

Table 2: Hosting Capacity available inside the TCMA

Substation	HCA	County	Substation	HCA	County	Substation	HCA	County
Merriam Park	41.13	Ramsey	West Coon Rapids	15.37	Hennepin	Air Lake	7.58	Dakota
Wilson	38.16	Hennepin	Rose Place	15.33	Ramsey	Glen Lake	7.31	Hennepin
Saint Louis Park	37.13	Hennepin	Battle Creek	14.34	Ramsey	Afton	7.22	Washington
Twin Lake	36.25	Hennepin	Lone Oak	14.05	Dakota	Hugo	7	Washington
Southtown	30.34	Hennepin	Rogers Lake	14	Dakota	Fifth Street	6.84	Hennepin
Edina	28.88	Hennepin	Elliott Park	13.88	Hennepin	Brooklyn Park	6.71	Hennepin
Medicine Lake	27.67	Hennepin	Main Street	13.52	Hennepin	Mound	6.71	Hennepin
Westgate	27.23	Ramsey	Elm Creek	12.84	Hennepin	Shepard	5.89	Ramsey
Upper Levee	25.88	Ramsey	Riverside	12.84	Hennepin	Hastings	5.55	Dakota
Parkers Lake	24.38	Hennepin	Gopher	12.33	Hennepin	Viking	5.46	Hennepin
Aldrich	24.28	Hennepin	Bassett Creek	12.24	Hennepin	Cedarvale	5.02	Dakota
Lexington	24.22	Ramsey	Summit Ave	12.21	Ramsey	Chemolite	5.02	Washington
Terminal	21.9	Hennepin	Ramsey	12.14	Ramsey	Long Lake	4.6	Washington
Dayton's Bluff	21.08	Ramsey	West River Road	12.12	Hennepin	Arden Hills	4.23	Ramsey
East Bloomington	19.49	Hennepin	Hiawatha West	11.61	Hennepin	Prior	3.96	Ramsey
Woodbury	19.32	Washington	Cottage Grove	11.55	Washington	Hollydale	3.44	Hennepin
Osseo	18.96	Hennepin	Stockyards	11.48	Ramsey	Baytown	3.18	Washington
Gleason Lake	18.9	Hennepin	Midtown	11.15	Hennepin	West Hastings	2.68	Dakota
Western	18.61	Ramsey	Hassan	10.87	Hennepin	Williams Brothers Propane	2.5	Dakota
Tanner's Lake	18.29	Ramsey	Airport	10.82	Hennepin	Vermillion	1.75	Dakota
Eden Prarie	16.96	Hennepin	Nine Mile Creek	10.32	Hennepin	Kegan Lake	1.22	Dakota
Red Rock	16.87	Dakota	Kohlman Lake	10.13	Ramsey	Pine Bend	0.91	Dakota
Oakdale	15.97	Washington	Indiana	9.85	Hennepin	Farmington	0.61	Dakota
Hyland Lake	15.41	Hennepin	Cedar Lake	9.34	Hennepin		**105.39**	
	587.31		Deephaven	8.89	Hennepin	Total	**995.92**	
				303.22				

Additionally, Xcel may realize potential reliability benefits from HDS at substations inside the TCMA, depending on the times at which the substations in the TCMA peak compared to the Xcel system peak. When substations inside the TCMA peak at different times, the distribution system would be less stressed because of the diversity in peak hour across the TCMA compared to the Xcel system peak.

Treating TCMA without HDS is similar to modeling a lumpsum single 10 MW unit. But with multiple substations modeled within TCMA as 10 – 1 MW units, better reliability is seen by a reduction in Expected Unserved Energy[31] (EUE) during the peak demand hours. Hence there is a reliability benefit of locating HDS across the TCMA. Unfortunately, we have not been able to determine the peak times for TCMA substations. In response to discovery requests on this subject, Xcel did not provide the necessary information citing grid security concerns.

F. Outside the Twin Cities Metro Area

1. Capacity benefits of locating HDS outside the Twin Cities Metro Area (TCMA)

Locating HDS outside the TCMA can also provide a capacity benefit when those resources participate in MISO's planning auction via FRAP. Xcel is part of Local Resource Zone (LRZ) 1 in the MISO auction, and any transmission limitations with other zones are reflected in the Capacity Import Limits (CIL) and Capacity Export Limits (CEL) calculations[32] in the MISO auction. This MISO modeling ensures transmission limitations between the zones are considered when determining the

[31] Attachment A Supplement Details, "Expected Unserved Energy (MWh) is total amount of energy that could not be served." Page 164 of 176

[32] MISO 2020/21 PRA results, 04/14/2020: MISO Planning Resource Auction (PRA) for Planning Year 2020-2021 Results Posting, slide 3 of 17, https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf

LSE requirements to meet PRMR. Xcel can address capacity needs by having HDS resources participate in the MISO auction,whether those resources are located inside or outside the TCMA.

2. Reliability benefits of HDS outside the TCMA

HDS resources outside the TCMA also provide reliability benefits to Xcel. There is approximately 300 MW of hosting capacity available at substations outside the TCMA, as shown in Table 3. This 300 MW could supplement Xcel's MISO capacity obligations because this 300 MW is also part of MISO LRZ1.

Table 3: Hosting Capacity available outside the TCMA

Substation	HCA	Substation	HCA	Substation	HCA	Substation	HCA	Substation	HCA	
Moore Lake	25.5	Fair Park	4.07	Birch	1.3	Tracy	0.46	Westport	0.06	
Goose Lake	15.96	Credit River	3.87	South Ridge	1.29	Frontenac	0.45	Essig	0.04	
Eastwood	15.77	Rich Valley	3.87	Albany	1.26	Wobegon Trail	0.45	Sedan	0.04	
Winona	10.29	West Faribault	3.68	Dahlgren	1.22	Blue Herron	0.42	West Union	0.03	
Coon Creek	9.72	Dodge Center	3.6	Saint Joseph	1.21	Stewart	0.42	Rosemount	0.01	
Oak Park	9.72	Sauk River	3.48	Cannon Falls	1.12	Gibbon	0.41			
Waseca	9.65	Kasson	3.37	Yellow Medicine	1.12	Lake Yankton	0.37			
Goodview	9.23	Pipestone	3	Pine Island	1.09	Bird Island	0.3			
Savage	8.78	Orono	2.96	Maple Lake	1.08	Henderson	0.3			
Bluff Creek	8.54	Excelsior	2.52	Cannon Falls Transmission	0.94	Mazeppa	0.3			
Sibley Park	8.08	Waconia	2.49	Rich Spring	0.93	Rapidan	0.29			
Crossroads	7.63	Burnside	2.42	Watertown	0.92	Green Isle	0.21			
Crooked Lake	7.05	La Crescant	2.36	Gaylord	0.9	Kenyon	0.21			
Granite City	7.02	Plato	2.08	Swan Lake	0.89	Lafayette	0.19			
Red Wing	6.23	Montevideo	2.07	Slayton West	0.76	Villard	0.18			
Blue Lake	6.17	Linn Street	2.01	Dassel	0.6	Hadley	0.17			
Riverwood	6.08	Wakefield	1.97	Eagle Lake	0.54	Cokato	0.16			
Salida Crossing	6.03	Wabasha	1.92	Greenfield	0.54	Sacred Heart	0.16			
Northfield	4.95	East Winona	1.88	Vesili	0.54	Butterfield	0.15			
Faribault	4.72	Jordan	1.87	Renville	0.5	Becker	0.11			
Lake Bavaria	4.42	Crystal Foods	1.76	Kimball	0.48	Belle Plain	0.1			
Saint Cloud	4.4	Fiesta City	1.74	Paynesville Transmission	0.48	Brownton	0.1			
Wyoming	4.39	Atwater	1.42	Danube	0.47	Castle Rock	0.1			
Dundas	4.31	First Lake	1.36	Franklin	0.47	South Haven	0.1			
	205	Howard Lake	1.32	Saint John's	0.47	Meeker	0.09			TOTAL
			63		**21**		**6**		**0.18**	**295**

G. HDS interconnecting to a Wholesale Distribution Service (WDS Facility)

This report has discussed the benefits of Xcel registering HDS as a MISO market resource**.** Alternatively, according to MISO, a DER provider, i.e., HDS operator, could contact MISO directly to determine whether a facility the HDS operator seeks to interconnect is within the PUC jurisdiction or MISO functional control:

> *"there are* ***two methods that DER*** *could use to ascertain the process applicable to its interconnection request. First, the DER could contact the Host Distribution Provider to determine whether the MISO process or the Host Distribution Provider's process applies to a given facility. Second, the DER could obtain this information directly from MISO[33]."*

Xcel owned transmission facilities transferred to MISO are called Transferred Transmission Facilities ("TTF"). Similarly, if distribution connected HDS is connected to the MISO transmission system and under MISO functional control, it is called Wholesale Distribution Service (WDS Facility).

Since MISO does not have any WDS facilities to-date (per their data request response to FERC), this approach could be discussed actively at MISO's FERC order 2222 related stakeholder DER Task Force because FERC Order 2222 mandates MISO to provide opportunities for DERs to participate in MISO energy, capacity, and ancillary services markets. Any HDS above 100 kW qualifies as a DER per FERC definition in this Order 2222.

Hence WDS Facilities are distribution system elements like TCMA substations discussed earlier where a Distributed Energy Resource (DER) provider like customer-owned HDS interconnects to a distribution facility to access MISO

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[33] In MISO response to the Federal Energy Regulatory Commission (FERC) data request on Distributed Energy Resource Aggregation (DERA) docket # RM18-9.

market benefits. As a result, this WDS facility becomes part of the MISO functional control list of Transferred Transmission Facilities (TTF).

1. Why is WDS Facility important for HDS interconnection?

MISO Generator interconnection queue request is one way to access the MISO transmission system. As this report has previously recommended, given that Xcel has no control over the MISO queue process, and the MISO queue is backed up by more than a few years, Xcel can work right away with HDS owners by studying the interconnections to Xcel's distribution system without waiting for MISO's study results. Xcel can submit Transmission Service Requests for the distribution connected HDS for MISO to grant transmission access. Xcel can reduce its capacity obligation by pointing to Aggregated HDS (which has transmission access) in its Fixed Resource Adequacy Plan (FRAP) at MISO's capacity auction.

To obtain MISO transmission service, MISO has explained that[34] a WDS Facility can take one of two alternate paths: 1) Apply for an External – Network Resource Interconnection Service (E-NRIS), or 2) Apply for a specific Point-To-Point or Network transmission service[35]. Because both inside and outside TCMA

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[34] In MISO response to the Federal Energy Regulatory Commission (FERC) data request on Distributed Energy Resource Aggregation (DERA) docket # RM18-9.

[35] Search for docket #, RM18-9, and filed date of October 07, 2019 in this FERC eLibrary, https://elibrary.ferc.gov/idmws/search/fercgensearch.asp "MISO provides two services that a DER must choose between for MISO to study the DER's deliverability: (1) External Network Resource Interconnection Service ("E- NRIS"); or (2) firm Transmission Service (either Point-To-Point or Network) from the DER unit to a particular load. If the DER elects to obtain E-NRIS, they must submit an Interconnection Request specifying that the DER is seeking E-NRIS and be studied through MISO's 3-phase DPP (described above). If the DER elects to obtain firm Transmission Service to be deliverable to specific load, then the Interconnection Customer must submit a Transmission Service Reservation ("TSR") and adhere to MISO's TSR study procedures"

substations are within MISO LRZ1, Xcel can apply for HDS to seek a specific Point-To-Point transmission service.

As the "host distribution provider," Xcel would aggregate the HDS resources and participate in the MISO market. **Hence there already exists a path for HDS to participate as a DER at MISO**.

While we do not know if Xcel has already discussed the option of using WDS facilities to register HDS as DER at MISO, it is clear that Xcel has an opportunity to do as it works with MISO at the DER Task Force for FERC Order 2222 implementation.

To summarize, if Xcel thoroughly vets the HDS interconnection at a WDS facility, there is a potential for more of Xcel's facilities to be transferred to MISO functional control. The specific facilities to be transferred to MISO would depend on Xcel's hosting capacity analysis since Xcel is the distribution utility. MISO, as the transmission provider, would coordinate with Xcel.

III. Effective Load Carrying Capability (ELCC) calculation of HDS

Effective Load Carrying Capability (ELCC) is the standard metric to determine a variable resource's contribution to serving demand. Xcel does not sufficiently analyze the ELCC for distributed solar relative to utility-scale solar in its supplemental IRP. Xcel states:

> *"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[36]."*

There is a direct relationship between capacity credit and ELCC. ELCC is calculated as a first step towards determining the capacity credit of the resource. Capacity credit is how much capacity of a variable resource counts towards meeting a Load Serving Entity's (LSE) capacity obligations.

A. Xcel should model HDS to reflect the locational value of distributed solar in ELCC

MISO has experience calculating ELCC for wind. Due to solar as a DIR – FERC filing approval, MISO expected to start calculating ELCC for solar for the 2021-2022 Planning Year. But since the transmission interconnected solar MW threshold was not reached, MISO continues to assign 50% solar capacity credit for the next 2021/22 planning year[37]. This 50% credit is good news for HDS and Xcel.

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[36] Attachment A: Supplement Details, X. Modeling Scenario Sensitivity Analysis – PVRR & PVSC Summary, Page 136 of 176.

[37] MISO Planning Year 2021-2022 Wind & Solar Capacity Credit December 2020 DRAFT found here, "Total registered solar in the MISO system (including behind-the-meter) is projected to reach 4,635MW ICAP in December 2021. MISO will continue to use the current accreditation methodology for new solar resources until sufficient operational data is available to perform a solar capacity credit study."
https://cdn.misoenergy.org/DRAFT%202021%20Wind%20&%20Solar%20Capacity%20Credit%20Report503411.pdf

For solar, Xcel models ELCC at 50%[38] for 2020-23 and 30% for the next 10 years, reflecting the conventional wisdom that increasing renewable penetration eventually leads to lower ELCC eventually (as illustrated by increasing wind penetration in MISO). Since ELCC is inversely proportional to the solar registered as a percentage of peak load in the MISO market, as solar market registrations increase, there is reason to believe ELCC % would decrease.

Historical MISO ELCC data for wind shows, even though the MISO system-wide average capacity credit for wind is approximately 15%, individual CPNodes have a higher credit based on their geographic location.

> "*While evaluation of all CPNodes captures the benefit of the geographic diversity, it is also important to assign the capacity credit of wind at the individual CPNode locations to recognize the capacity contributions of each individual wind-generating unit. In a market, it is important to convey where wind resources are approximately more effective, and how the location and corresponding relative performance of each wind CPNode relates to the contribution of wind ELCC to system-wide reliability*[39]."

Similarly, **we can expect solar capacity credit to reflect a higher locational value for HDS** inside the TCMA versus outside the TCMA because the geographic

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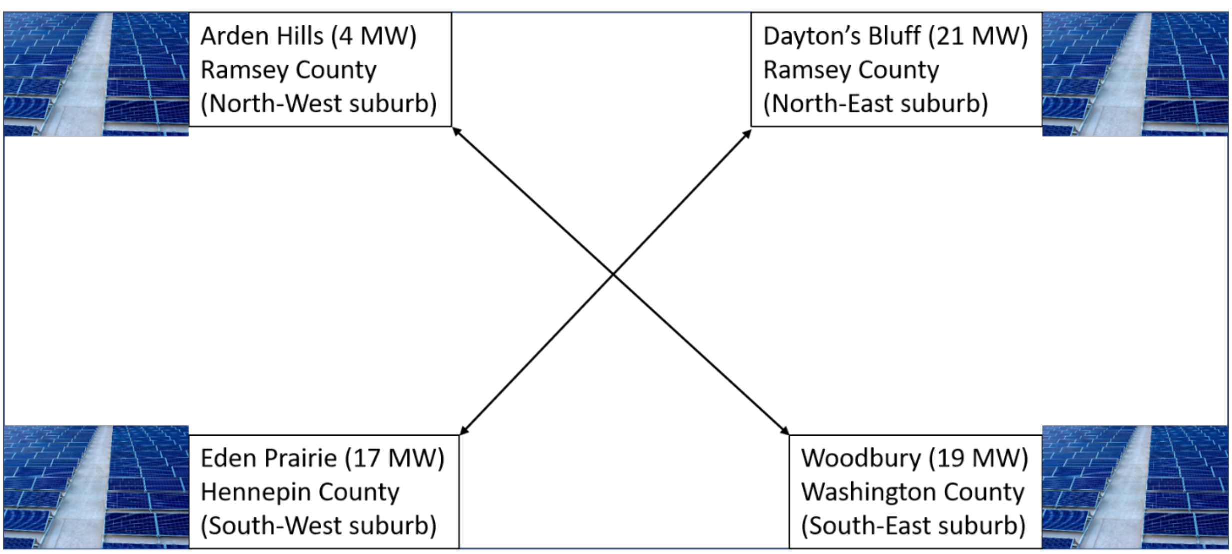
[38] Attachment A: Supplement Details, Page 88 of 176, "In the first several years of the analysis period, we use the current 50 percent ELCC, corresponding to a 250 MW accredited capacity for generic new solar. By 2033, however, the modeled ELCC declines to 30 percent, which would correspond to 150 MW of accredited solar capacity"

[39] Section 3, Details of Wind Capacity by CPNode, MISO report - Planning Year 2020-2021 Wind & Solar Capacity Credit December 2019.

diversity of HDS located at TCMA substations is reflected in a higher capacity credit at individual CPNode inside TCMA versus outside the TCMA.

ELCC for HDS is much better than for utility-scale Solar. If Xcel models HDS as outlined here in the TCMA, ELCC for some TCMA substations would reflect a higher locational value because it is unlikely that all substations in the TCMA would experience a peak load simultaneously.

For example, referring to the TCMA Hosting Capacity Table (Table 2: Hosting Capacity available inside the TCMA), Arden Hills in the TCMA is a North-West suburb, diagonally opposite Woodbury in the South-East suburb. Similarly, Eden Prairie is a South-West suburb, is diagonally opposite Dayton's Bluff in the North-East suburb, as shown in Figure 2. As a result, the contribution of HDS increases by spreading across the metro area, compared to a single utility-scale solar unit at one location.



Source for solar picture - Photo by [Angie Warren] on [Unsplash]

Figure 2: HDS at TCMA Substations provides locational value

This benefit of locating HDS at multiple substations across the TCMA, reducing the risk of placing solar at a single Generation EPNode[40] (unfortunately, Xcel has not shared the peak times, citing "grid security" concerns), is similar to the MISO footprint diversity benefit. **MISO estimates more than $2 billion[41] in footprint diversity** benefits for its members because hypothetically, the peak demand of MISO east members (located in Michigan) does not occur at the same time as the peak demand of MISO west members (located in Minnesota).

Therefore, it is reasonable, and this report recommends that Xcel apply MISO footprint diversity to HDS inside and outside the TCMA.

Xcel is aware of the locational value of resources, specifically wind[42].

> *"We note that we have shifted from using the MISO footprint average wind ELCC of 15.6 percent to the most recent Zone 1 specific ELCC of 16.7 percent, in order to better capture **the higher locational value** of wind resources in our specific region"*

Hence it reasonable to expect Xcel to model HDS and test the hypothesis of higher locational value for HDS in the TCMA, which may result in a higher ELCC.

A higher ELCC for HDS translates into a higher capacity credit.

To summarize, Xcel did not account for the potential locational benefits of HDS, and adjust the ELCC for distributed solar accordingly. In markets and regions

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[40] Responses to 19-0368 VS ILSR CEF-020 onwards reference

[41] MISO 2019 Value Proposition, slide 11 of 16, https://cdn.misoenergy.org/20200214%202019%20Value%20Proposition%20Presentation425712.pdf

[42] Supplemental IRP footnote 14, page 22 of 78

where there is high penetration of distributed solar such as TCMA, there is a higher ELCC value for HDS that Xcel should have reflected in this supplemental IRP.

IV. Transmission reliability evaluation of HDS

Proper accounting of the impact of distributed solar dispatch is required in the transmission planning models because it ensures an accurate transmission needs assessment. Moreover, the MISO 2021 capacity expansion model shows economic potential for 3,400 MWs of DG PV on the low end and 6,000 MW on the high end[43]. Xcel and MISO must account for distributed solar in their planning models to stay compliant with NERC standards and portray an accurate transmission needs assessment.

A. Proper accounting of solar dispatch impact leads to accurate transmission needs assessment

Both utility-scale solar and HDS must be dispatched in the MISO transmission planning models to meet NERC Transmission Planning (TPL) and Model Building (MOD) compliance standards. The MISO planning models are used for justifying transmission projects in the MISO region. Proper accounting for the solar dispatch in these planning models ensures that distributed solar is treated in the same manner as any other capacity resource in those models. Which, in turn, ensures accurate transmission needs assessment.

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[43] MISO Planning Advisory Committee October 14, 2020, agenda item 3a, MTEP21 Futures Resource Expansion and Siting Results, slide 3 of 9, https://cdn.misoenergy.org/20201014%20PAC%20Item%2003a%20MTEP21%20Futures%20Resource%20Expansion%20and%20Siting%20Results482500.pdf

1. <u>Xcel has a NERC compliance obligation to dispatch distributed solar accurately in transmission planning models</u>

For transmission connected solar, MISO proposed to dispatch solar at 31% on average[44]. This assumption for dispatch percentage is the NERC transmission planning standard TPL-001-4 requirement R2.1.2. Since MISO has no experience with distributed solar resources connected to the transmission system yet, there is no discussion on distributed solar dispatch percentages in MISO planning stakeholder committees.

MISO's recent Transmission Expansion Plan (MTEP) 2021 capacity expansion model forecasts 3.42 Giga Watts (GW) of DG PV on the low end and 6.08 GW on the high end in the next 20 years, compared to Xcel's 1,778[45] MW forecast for the next 15 years. This 3,420 Mega Watts (MW) plus DG PV[46] is sited in the MISO economic models for detailed economic and reliability planning in the next few months leading to transmission project recommendation in December 2021.

As the NERC Planning Coordinator, MISO must submit transmission planning models to NERC to stay compliant with applicable transmission planning and model building standards. Hence MISO must dispatch distributed solar forecasted

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[44] MISO Planning Advisory Committee August 12, 2020, agenda item 3e, Wind and Solar Gen Dispatch, slide 5 of 8, https://cdn.misoenergy.org/20200812%20PAC%20Item%2003e%20Wind%20and%20Solar%20Gen%20Dispatch%20Presentation465534.pdf

[45] Figure III-2: High Distributed Solar Adoption Scenario Forecast, Attachment A: Supplement Details, page 39 of 176.

[46] MISO Planning Advisory Committee October 14, 2020, agenda item 3a, MTEP21 Futures Resource Expansion and Siting Results, slide 3 of 9, https://cdn.misoenergy.org/20201014%20PAC%20Item%2003a%20MTEP21%20Futures%20Resource%20Expansion%20and%20Siting%20Results482500.pdf

in the MTEP 2021 in both reliability and economic planning models to stay compliant.

Xcel, as MISO Transmission Owner (TO), has delegated some of the Transmission Planning (TPL) and Model Building (MOD) responsibility to MISO as part of the coordination and delegation agreement[47]. Hence, Xcel's NERC compliance obligations are tied to MISO's for the dispatch of distributed solar in the planning models.

2. MISO has a FERC compliance obligation with distributed solar

In addition to upcoming FERC Order 2222 compliance, MISO has FERC compliance requirements related to the Dispatchable Intermittent Resource (DIR) tariff for solar. FERC accepted MISO's DIR filing[48] that,

"*require all solar resources that enter commercial operation on or after March 15, 2020 to register and become dispatchable by March 15, 2022, and solar resources in commercial operation prior to March 15, 2020 have the option to become DIRs, but are not required to do so.*"

Xcel's transmission-connected solar with an in-service date on or after March 15, 2020, must become dispatchable by March 15, 2022. Hence Xcel's solar resources are dispatched by the MISO SCED and control room operator starting March 15,

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[47] MISO Compliance Corner website with link to MISO Coordinated Functional Registration document showing TPL-001-4 as part of the agreement with TOs, https://cdn.misoenergy.org//2018-11-28%20Coordinated%20Functional%20Registration_CFR_final298937.pdf

[48] FERC approval of MISO's Solar DIR filing, https://cdn.misoenergy.org/2020-06-09%20171%20FERC%20%C2%B6%2061,203%20Docket%20No.%20ER20-595-000;%20-001452020.pdf

2022. This MISO responsibility should address Xcel's concerns that an HDS scenario[49] leads to reliability concerns for all hours.

This solar dispatchability market benefit is the same benefit Xcel receives with the rest of the MISO market resources.

To summarize, Xcel and MISO need to account for distributed solar in their planning models based on MISO's MTEP 2021 capacity models forecasting for DG PV. Additionally, MISO must stay compliant with the FERC solar DIR tariff. So, distributed solar dispatch impact is another reason for Xcel to account for an HDS future appropriately.

B. Transmission needs would be reduced by HDS locations inside and outside TCMA relative to the Xcel system peak

We know Xcel did not run a detailed transmission limitations study that includes HDS[50]. If Xcel had run a transmission limitations study with HDS, we would have information on the line ratings on transmission lines, transformers, and substations limiting the power transfers in the TCMA with the addition of HDS capacity.

Additionally, as indicated by Xcel's response to Data Request 19-0368 VS ILSR CEF-004[51], transmission projects are identified by MISO utilities in the Twin Cities

[49] SUPPLEMENT 2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN DOCKET NO. E002/RP-19-368, Footnote # 21, page 38 of 78, "where vast amounts of variable renewable generation and use limited resources are selected – lead to questions regarding the ability of these portfolios to meet customers' reliability needs across every hour of every day"
[50] Xcel response to 19-0368 VS ILSR CEF-003, "our Integrated Resource Planning process is primarily focused on size, type, and timing of potential future resource additions. As such, we do not examine locational aspects of specific distributed resource additions in the IRP".
[51] Xcel responses to 19-0368 VS ILSR CEF-010 through 19-0368 VS ILSR CEF-013 also refer to 19-0368 VS ILSR CEF-004.

Zone[52]. If Xcel modeled HDS in transmission reliability models, we would have information on which of the following MISO transmission projects in Table 4 can be deferred or additional ones needed.

Table 4: Twin Cities Zone Transmission Projects

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wires Alt.	Utility
2017-TC-N1	Airport-Rogers Lake 115 kV Rebuild	2016/B>A	10074	No	No	XEL
2017-TC-N4	Black Dog-Wilson 115 kV Uprate	2017/C>A	11993	No	No	XEL
2017-TC-N5	Wilson Substation	2017/C>A	4695	No	No	XEL
2017-TC-N6	Plymouth-Area Power Upgrade	2018/C>A	14054	No	Yes	XEL
2017-TC-N7	Lebanon Hills 115 kV	2018/A	12211	No	No	GRE
2019-TC-N1	Red Rock Transformer Uprate	2018/A	14844	No	No	XEL
2019-TC-N2	South Afton Substation	2019/A	15730	No	No	XEL
2019-TC-N3	East Metro Area Upgrades	2019/A	15877	No	No	XEL

[52] See section 6.6.1, http://www.minnelectrans.com/documents/2019_Biennial_Report/html/Ch_6_Needs.htm#sec6.6

With the more than 3,000 MW of DG PV projected to be added to MISO capacity expansion models, Xcel and the rest of MISO's Minnesota utilities must tackle this transmission reliability challenge in MTEP 2021.

Additionally, Xcel did not model import and export analysis with and without HDS[53]. Also, LOLE analysis was not conducted for capacity inside the TCMA and outside the TCMA[54]. As a result, we don't have a quantification of reliability benefits of HDS and we don't know if the transmission needs are accurate inside the Twin Cities Zone of Minnesota Electric Transmission Planning website.

C. Xcel should quantify the diversity in TCMA substations peak demand hours.

Footprint diversity is a benefit that occurs when Minnesota's peak demand hour does not occur at the same time as Michigan's peak demand hour (both states are in the same MISO market). This peak demand diversity allows MISO operators to dispatch resources for Minnesota, and then, when a peak occurs in Michigan – procure resources for Michigan.

Similarly, for the purposes of this IRP– Xcel should quantify the diversity benefit provided by the potentially varying peak demand hour at different substations in the TCMA relative to the Xcel system peak.

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[53] Xcel response to 19-0368 VS ILSR CEF-019, "We interpret "import/export analysis" to mean analyses on import and export limits. We have not analyzed import and export limits both with and without HDS."
[54] Xcel response to 19-0368 VS ILSR CEF-017, "We have not conducted an LOLE analysis that replaces some or all imports into the TMA with capacity added inside the TMA".

Xcel Data Request responses # 22 and 23 show both past and future peak demand hours for historical data. In this data, hours ending 16 and 17 are a common denominator.

And in Xcel's Integrated Distribution Plan – Annual Update, Attachment A – Page 4 of 26, Xcel states:

"*Minimum solar output curves utilized during the analyses ranged from 24-36% of peak output from 10AM to 4PM and to percentages less than that outside of that timeframe.*"

This indicates that most solar output occurs hour ending 16 and Xcel system peak demand hours are those ending 16 and 17. Knowing this historical information, Xcel can store solar energy before the hour ending 16 and discharge during the 4-hour peak window of the hour ending 17 through 20. That reduces the stress on the transmission system.

Additionally, from Xcel IRP, Attachment A: Supplement Details, VI. Resource Attributes, page 109 of 176:

"*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*".

Hence, Xcel should quantify the impact of HDS on the transmission system around the TCMA. The transmission system around the TCMA would not be stressed when the Xcel system peaks. Historically Xcel demand did not peak at the same time as MISO zone 1 peak, as the table below illustrates.

Table 5 shows that when the NSP system peak is compared against the MISO zone 1 peak, out of the 14 years of comparable data, in 13 instances – the NSP system peaked at a different hour than the MISO zone 1 peak. So, 93% (13 divided by 14) of time NSP system peaked at a different hour than MISO zonal peak. This peak time diversity should not be discounted when transmission reliability is modeled.

Table 5: NSP System Peak comparison with MISO Zone 1 Peak Hour

NSP 60-minute Peak Demand				MISO Zone 1 Peak		
Year	Date	Hour-ending Central Time	Hour-ending. (MISO EST)	Date	Hour-ending. (MISO EST)	
2002	30-Jul	1600	1700	no data		
2003	20-Aug	1700	1800	no data		
2004	21-Jul	1600	1700	no data		
2005	12-Jul	1700	1800	1-Aug	1700	
2006	31-Jul	1600	1700	31-Jul	1600	
2007	26-Jul	1400	1500	9-Aug	1700	
2008	29-Jul	1400	1500	29-Jul	1400	
2009	23-Jun	1400	1500	23-Jun	1400	
2010	9-Aug	1700	1800	9-Aug	1600	
2011	20-Jul	1700	1800	20-Jul	1700	
2012	2-Jul	1700	1800	2-Jul	1500	
2013	26-Aug	1700	1800	26-Aug	1500	
2014	21-Aug	1700	1800	21-Jul	1500	
2015	14-Aug	1600	1700	14-Aug	1600	
2016	20-Jul	1700	1800	20-Jul	1700	
2017	17-Jul	1700	1800	17-Jul	1800	
2018	29-Jun	1700	1800	12-Jul	1700	

To summarize, the TCMA would peak at a different time than the NSP system peak. Hence, the HDS impact on reducing the TCMA's transmission system's stress should not be discounted.

IV. Conclusions

The Rakon Energy report took a deep dive into the modeling of HDS in NSP's SIRP. The scope of this report is to evaluate several considerations for high penetration DG impacts on the Company's system, including opportunities within the larger MISO market and how to ameliorate challenges and leverage opportunities. Here are the five main conclusions of this report.

First, NSP must improve its planning to include additional distributed resources and treat them as a "central element to the utility's optimized plan." In fact, due to market changes, technology development, and federal policy including FERC Order 2222, it is inevitable that greater distributed resource development will occur and will need to be accommodated by NSP plans. Planning for greater distributed resource penetration now allows efficient optimization rather than inefficient after-the-fact adjustments to the Company's resource plans.

Second, distributed resources interconnected to Xcel's distribution system avoid the MISO queue process that is currently backed up by more than a few years and which neither the Commission nor Xcel can control. Focusing on distributed resources would allow Xcel to integrate higher levels of renewable resources, in contrast with a focus on utility scale, transmission-interconnected, generation that must navigate the MISO interconnection queue.

Third, MISO is currently modeling more than 3,000 MWs of DG PV in 2021 transmission planning models. Those model runs demonstrate that a much higher level of distributed solar can be economically added to the system than Xcel is currently planning. That further confirms that NSP should revise and extend its assumptions beyond the level of distributed generation in its HDS sensitivity to determine transmission and distribution needs now.

Fourth, distributed solar, especially distribution connected DG within the Twin Cities Metro Area should have a higher Effective Load Carrying Capability than utility scale solar connected at transmission to remote nodes. Differences in the ELCC of resources has been shown to vary by interconnection node. Xcel and

MISO should jointly determine the capacity value of distributed resources through a locational capacity value ELCC.

Lastly, this report points out that that distribution connected solar avoids distribution and transmission system costs in addition to providing resource benefits. Aligning distribution, transmission, and resource planning will reveal currently unrealized value. The Commission should require Xcel to integrate distribution, transmission, and resources as part of its IRP to meet system's reliability needs most effectively, rather than through balkanized planning. High density distributed resources will produce higher locational capacity in and around the Twin Cities Metro Area and should be considered separately from other portions of NSP's service territory.

CERTIFICATE OF SERVICE

I hereby certify that on this 11th day of February 2021, I have served the foregoing document to the Minnesota Department of Commerce in Docket No. E002/RP-19-368 on the attached list of persons by transmitting a true and correct copy by electronic filing.

Dated: February 11, 2021.

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