



Utility Distributed Energy Forecasts:

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

By John Farrell
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ILSR INSTITUTE FOR
Local Self-Reliance

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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 outside 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](https://twitter.com/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.



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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

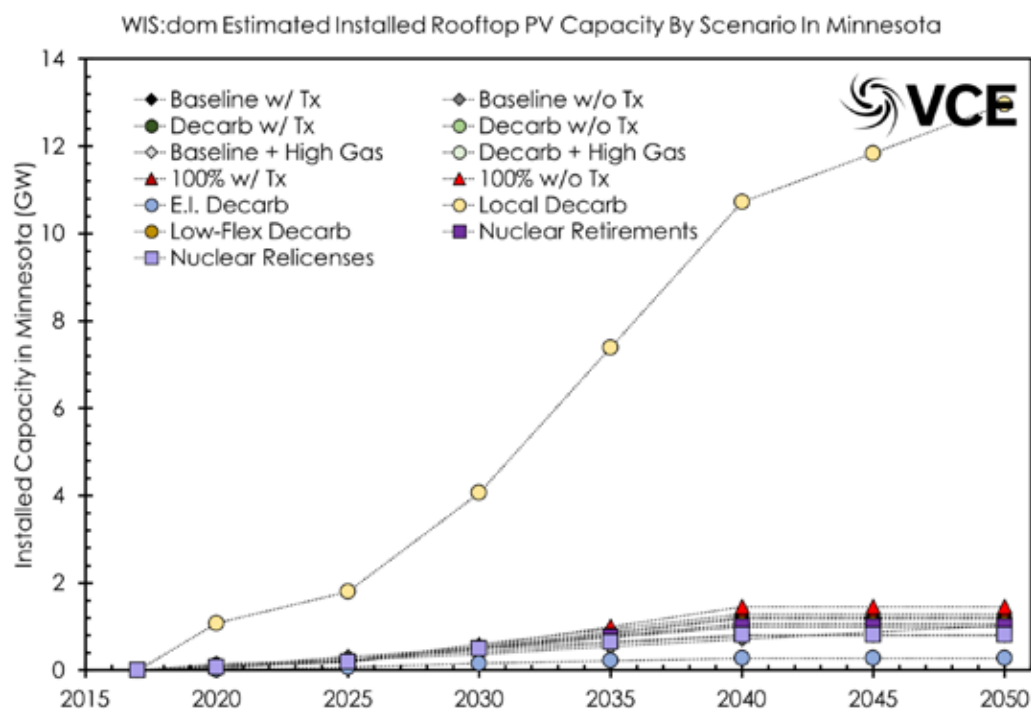
Customer solar adoption in Minnesota and many other states has grown rapidly in recent years, boosted by falling installation costs and state incentives. In Minnesota and a handful of states, solar adoption is also boosted by the availability of community solar programs. The following section illustrates 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.

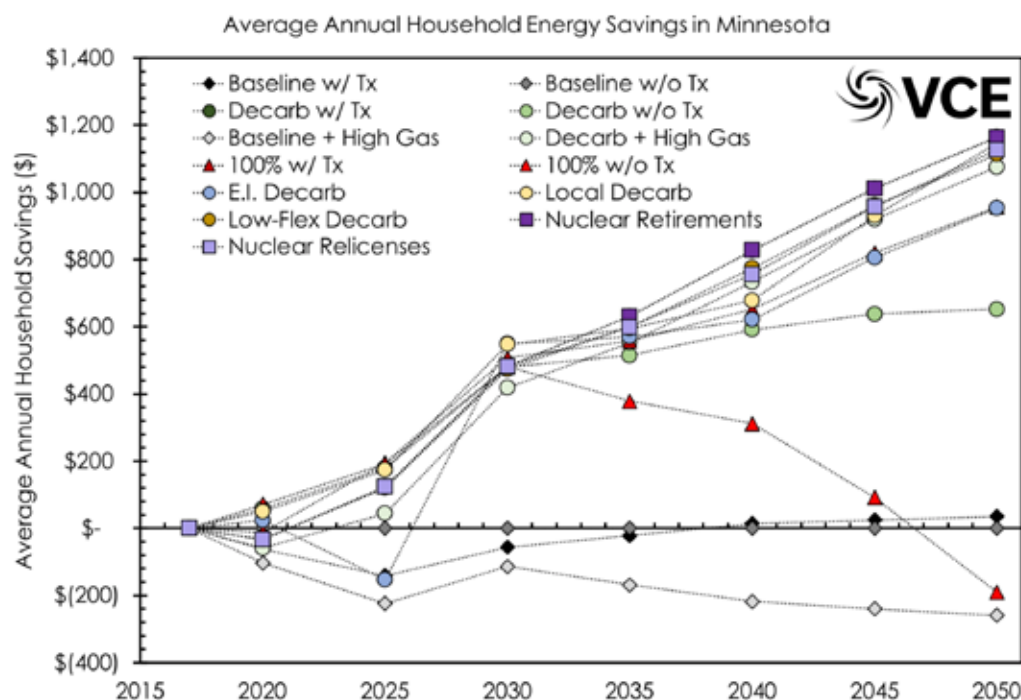
The following charts illustrate the opportunity. The first shows the quantity of installed rooftop solar in Minnesota through 2050 in the Vibrant Clean Energy Smarter Grid model.

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



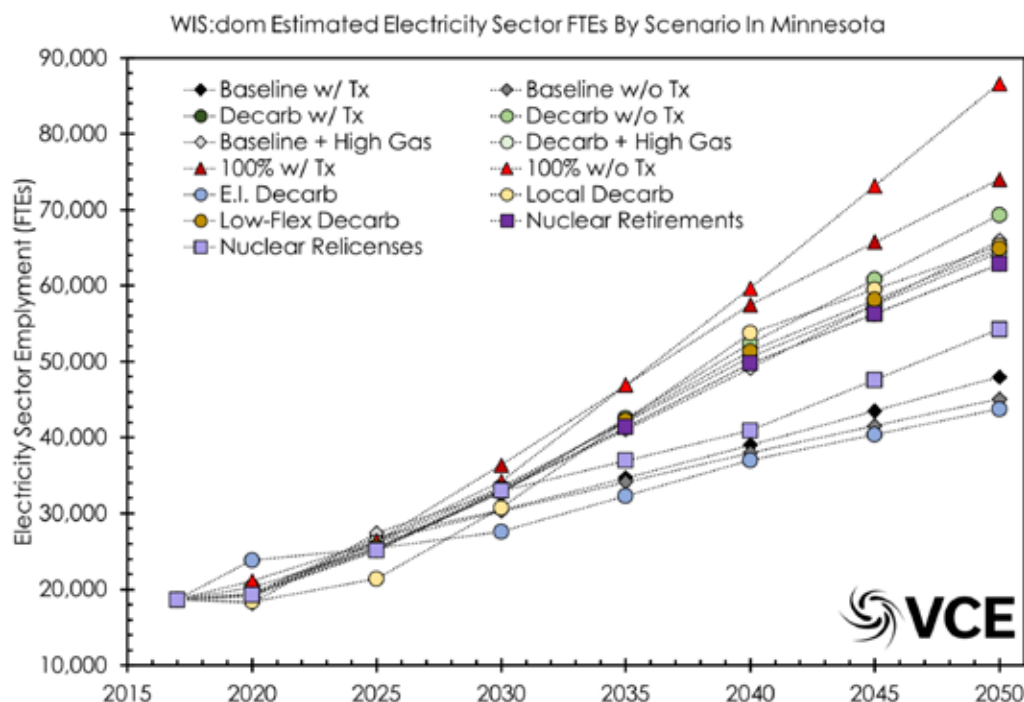
The second chart compares household energy savings for different decarbonization scenarios. The Local Decarbonization scenario, featuring 13 gigawatts of rooftop solar installed by 2050, provides close to the highest financial benefit. The dot representing the scenario, in yellow, is hidden just below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

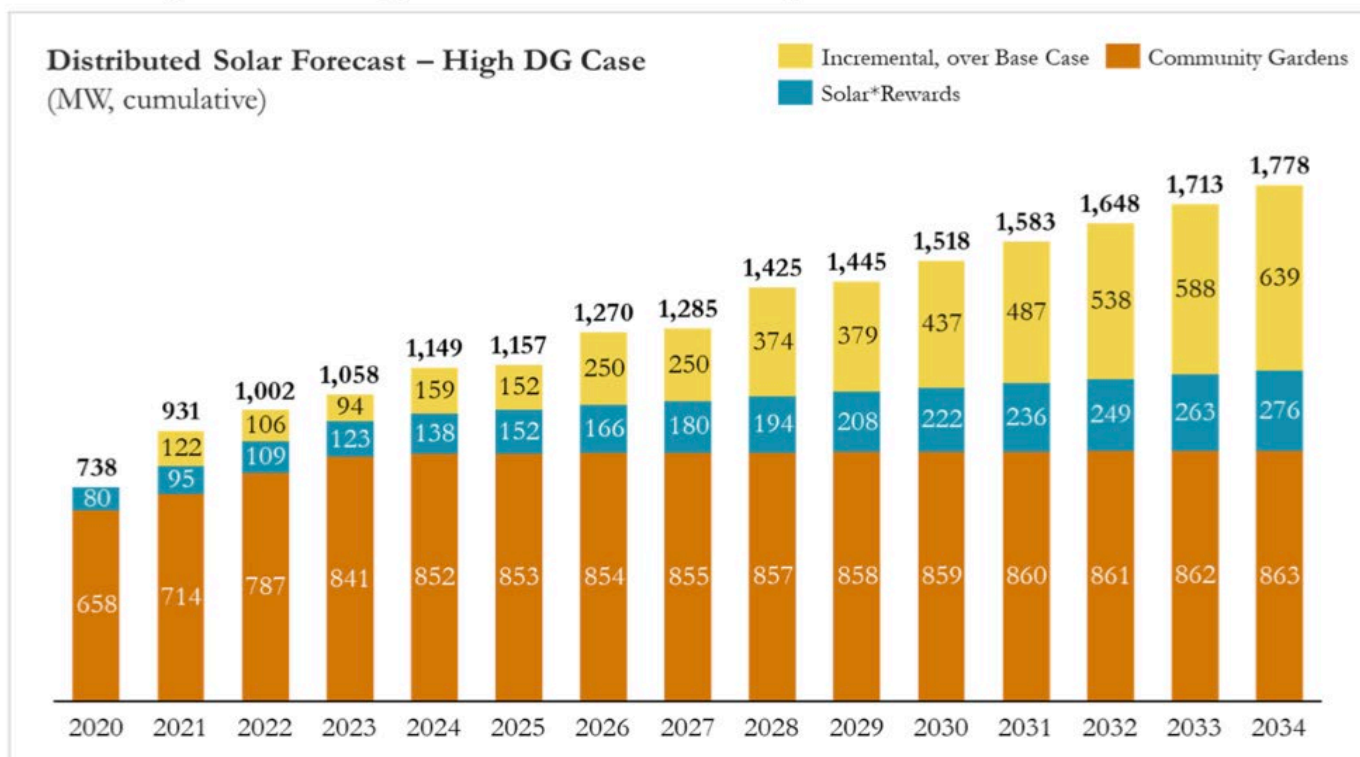
In its recently filed resource plan, Xcel Energy's rooftop solar forecast comes in low.¹ Its base case assumes roughly 275 megawatts of new rooftop solar by 2034, with no increase in the pace of adoption. The utility's High Distributed Solar (or High DG for "distributed generation") scenario adds 640 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 customers⁴
- 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/3dGL7gl>.

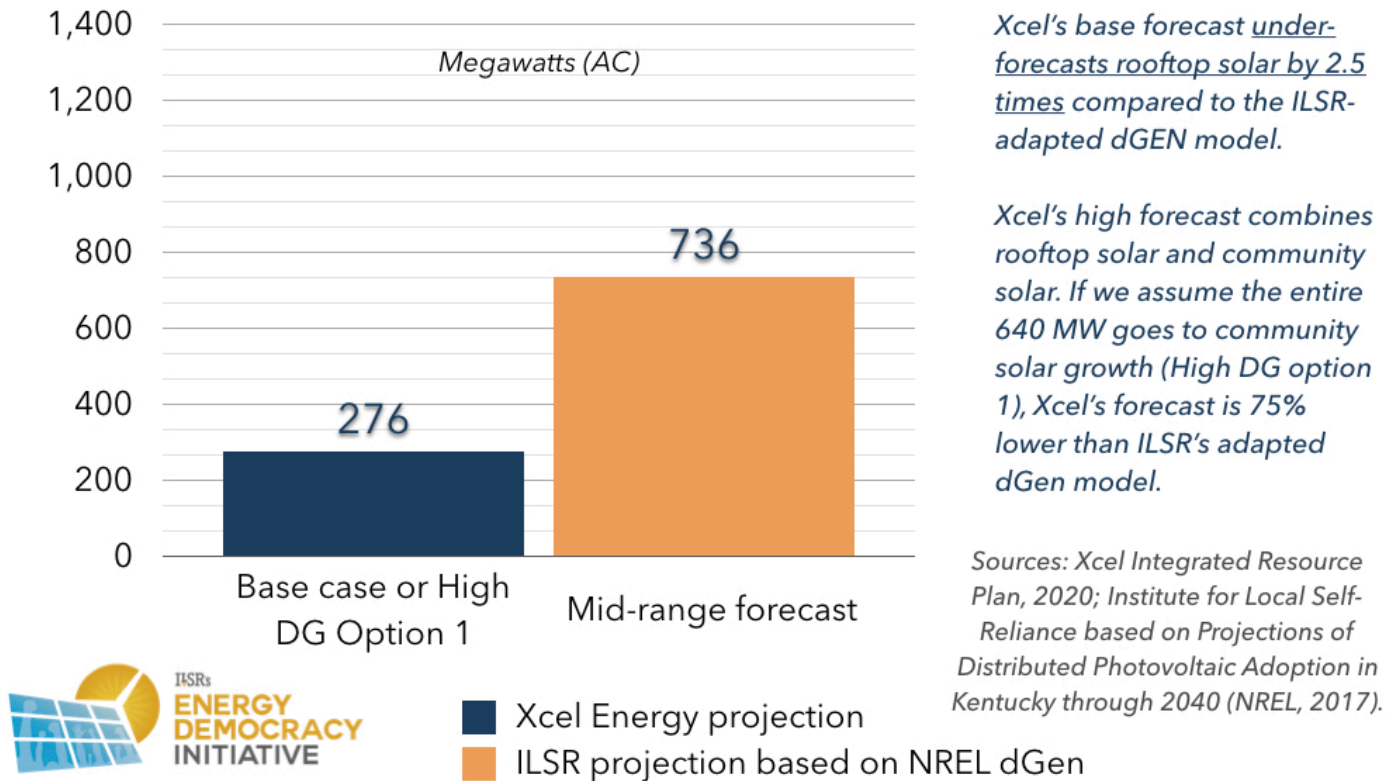
3. Distributed Energy Resources Data. (Minnesota Public Utilities Commission). <https://mn.gov/puc/energy/distributed-energy/data/>

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.

ROOFTOP SOLAR MODEL COMPARISON (LOW)

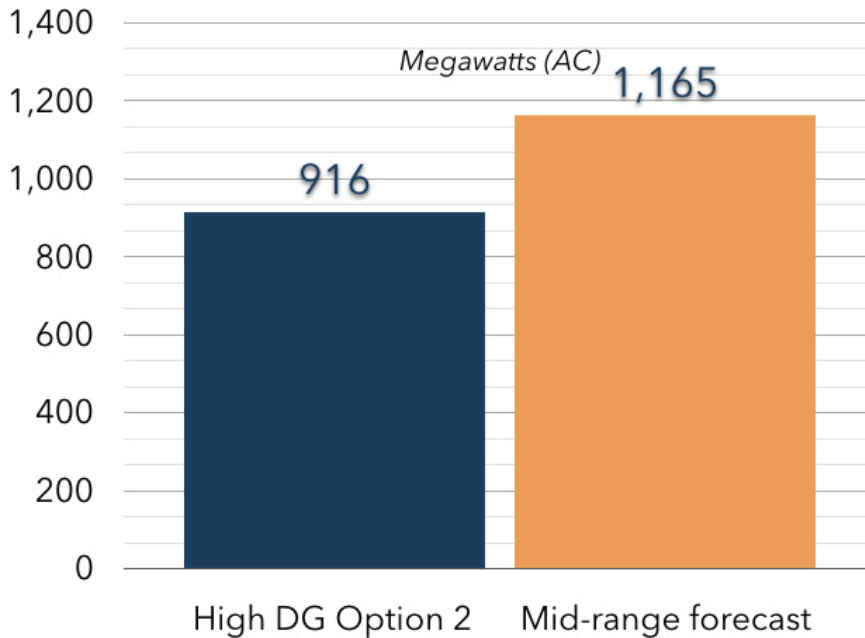
Xcel Energy's projections are implausible compared to an adapted NREL dGen forecast



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).



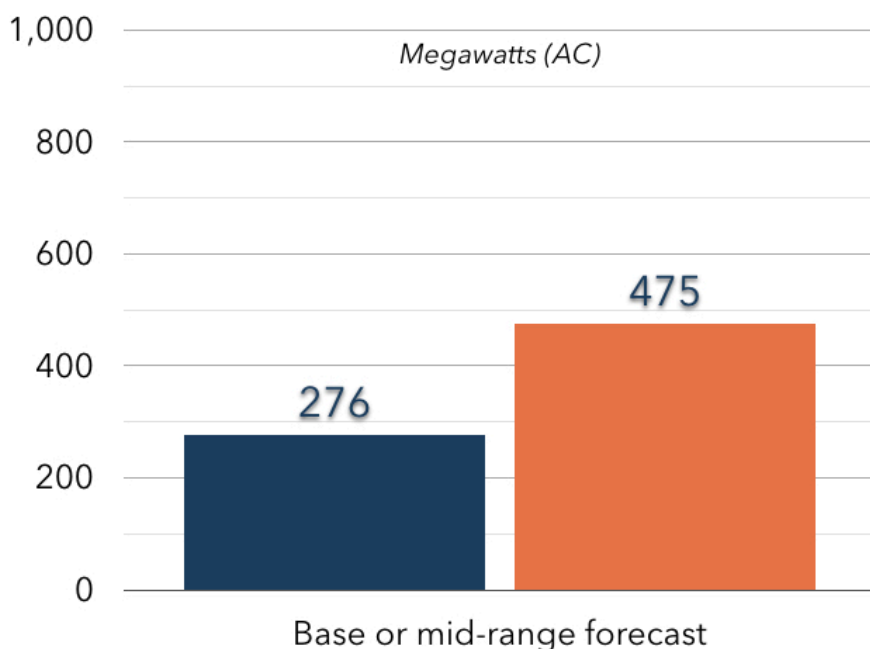
■ Xcel Energy projection
■ ILSR projection based on NREL dGen

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 residential solar only.**

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).

ROOFTOP SOLAR MODEL COMPARISON (BASE)

Xcel Energy's projections are implausible compared to the Williams, et al. model



Xcel Energy's base forecast under-forecasts customer-sited solar by half compared to the Williams, et al., model even though the Williams model only forecasts residential solar.

Sources: Xcel Integrated Resource Plan, 2020; Institute for Local Self-Reliance based on Williams, et al., (Dec. 2019).



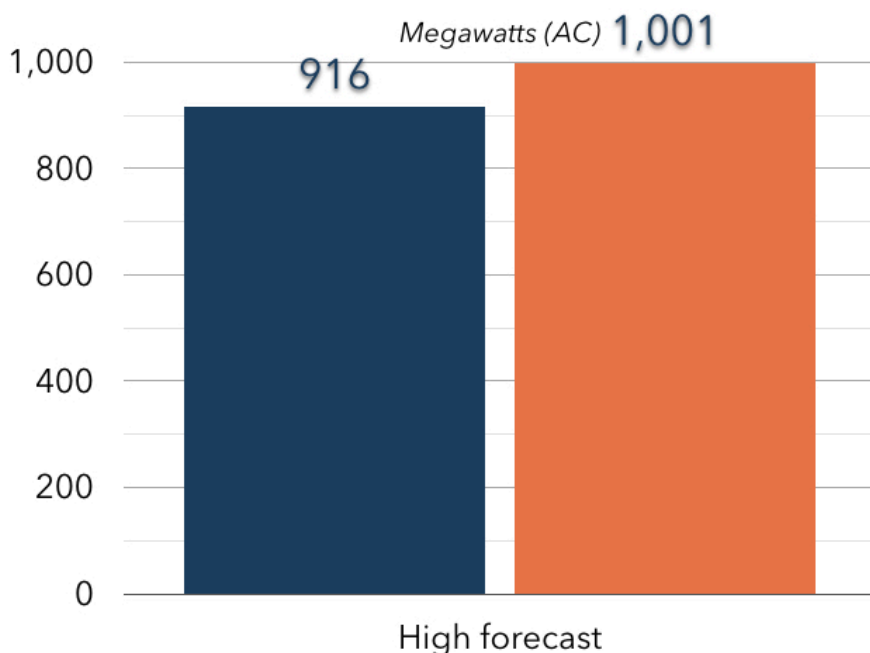
■ Xcel Energy projection
■ ILSR projection based on Williams, et al.

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.

ROOFTOP SOLAR MODEL COMPARISON (HIGH)

Xcel Energy's projections are implausible compared to the Williams, et al. model



Xcel Energy's high forecast implies near zero growth in community solar and undercounts solar by 30 MW compared to the Williams, et al., model even though the Williams model only forecasts residential solar.

Sources: Xcel Integrated Resource Plan, 2020; Institute for Local Self-Reliance based on Williams, et al., (Dec. 2019).



■ Xcel Energy projection
■ ILSR projection based on Williams, et al.

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—shown 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 on-line. 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>

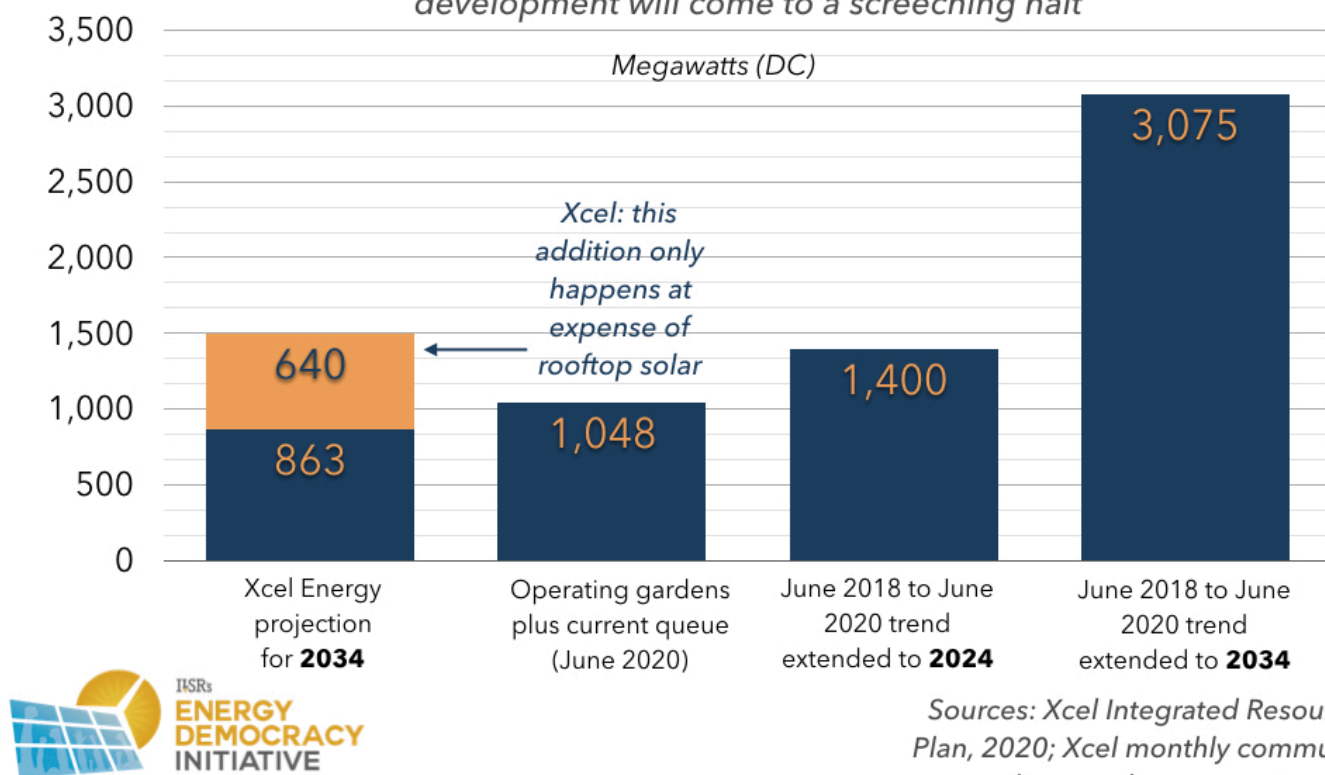
7. Farrell, John. Why Minnesota's Community Solar Program is the Best. (Institute for Local Self-Reliance, updated monthly). <https://ilsr.org/minnesotas-community-solar-program/>

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%.

COMMUNITY SOLAR PROJECTIONS

High DG forecast
Base forecast

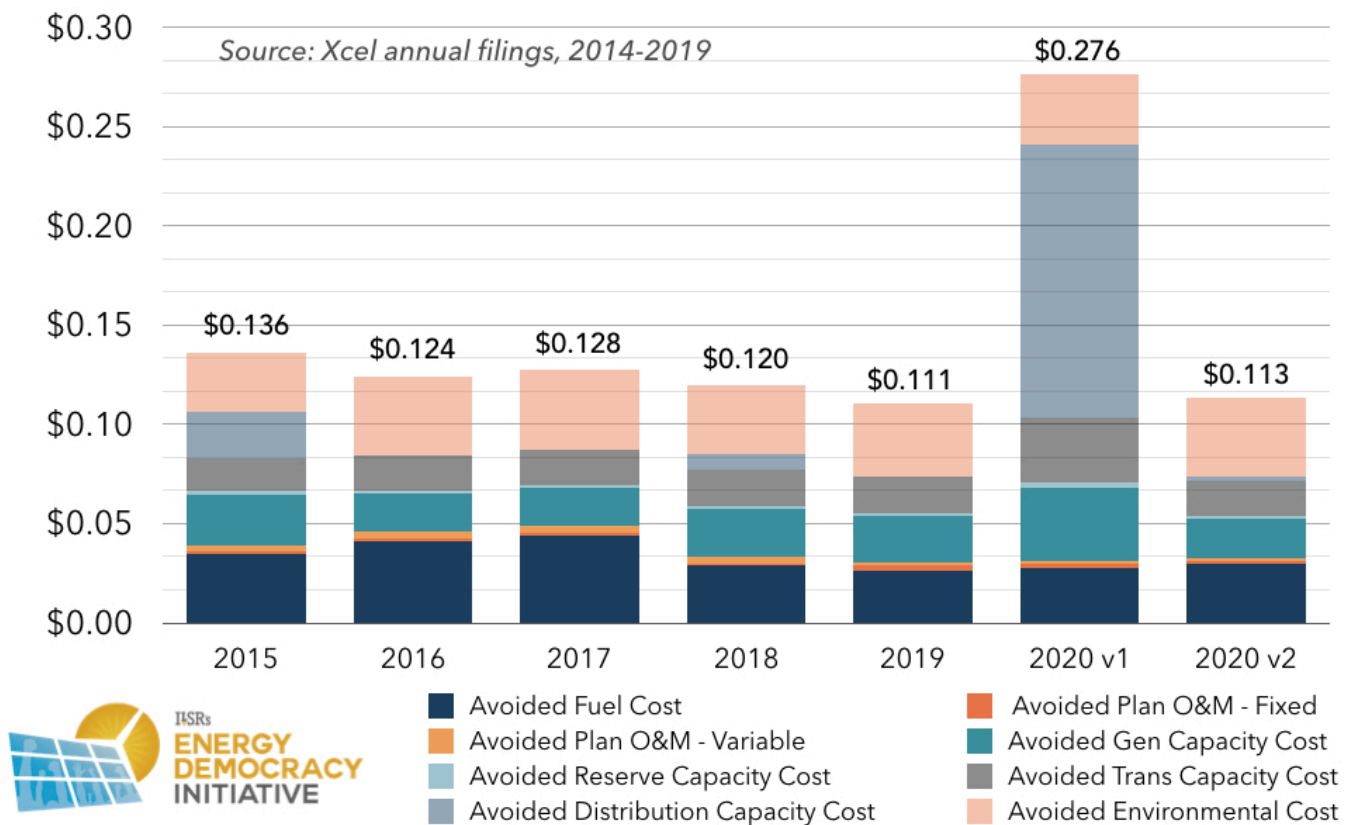
Xcel Energy's forecast barely accounts for projects in the queue and suggests development will come to a screeching halt



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

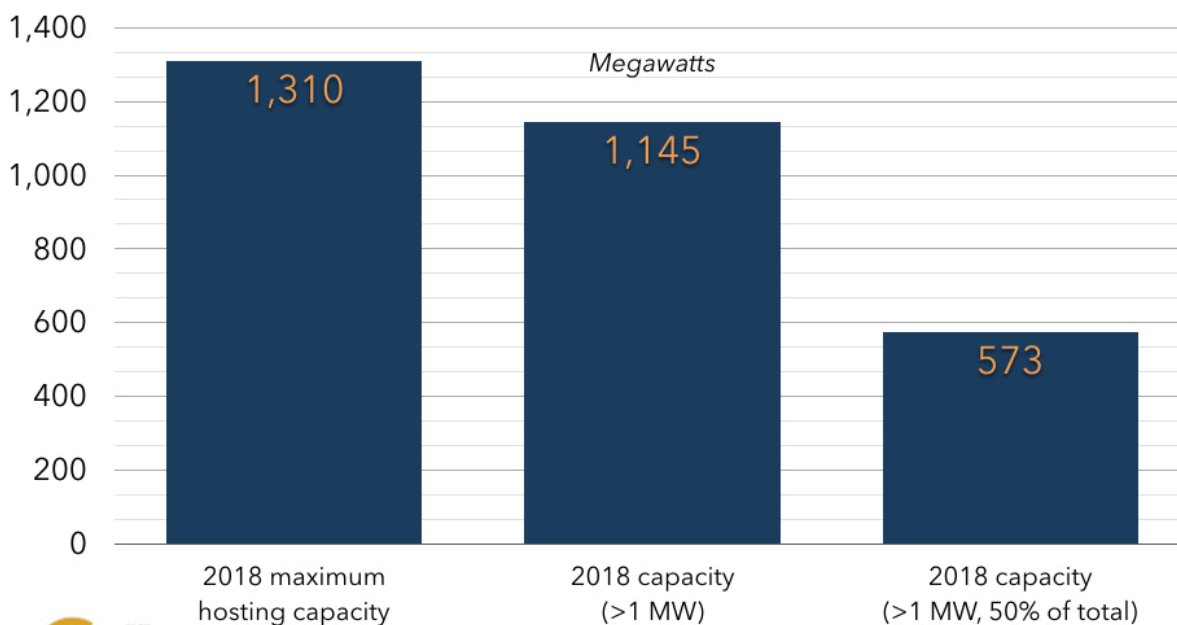
community solar (1 megawatt each) is shrinking. Overall, the total of maximum hosting capacity of all feeders on Xcel's system fell from 6,300 megawatts to 1,300 megawatts from the 2017 to 2018 analysis. The capacity for projects is further constrained in three ways (but also mitigated in others).

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.

XCEL HOSTING CAPACITY

Even with limitations, the distribution grid should be able to accommodate near-term community solar growth in Minnesota (Note: figures do not account for mitigating strategies to address capacity limitations, such as energy storage)



Source: Xcel hosting capacity analysis, Nov. 2018

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.

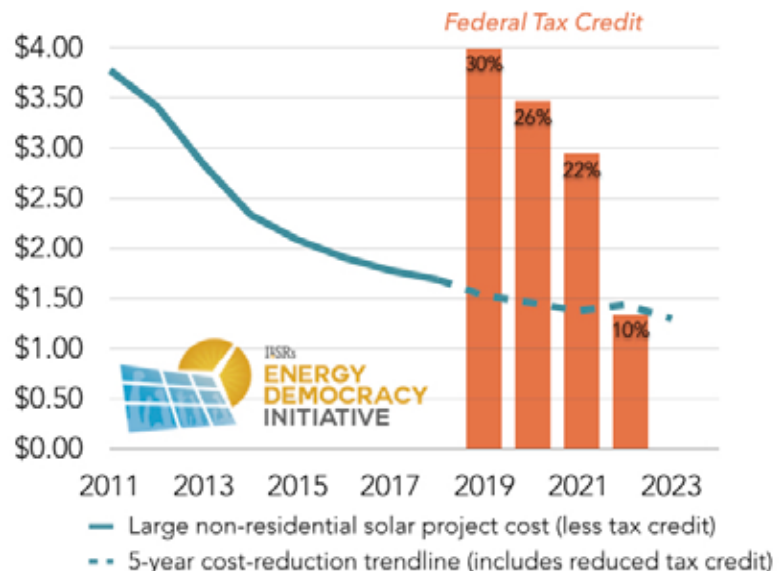
The Tax Credit Impact

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.

EXPIRING FEDERAL TAX CREDIT

The federal tax credit for commercial solar projects is falling from 30% to 10%. However, declining project costs may cover much of this reduction.



Source: Tracking the Sun, 2019 (Lawrence Berkeley Labs)

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 Naïm Dargouth. Tracking the Sun, 2019 Edition. (Berkeley Lab, October 2019). <https://bit.ly/3gVi9f3>

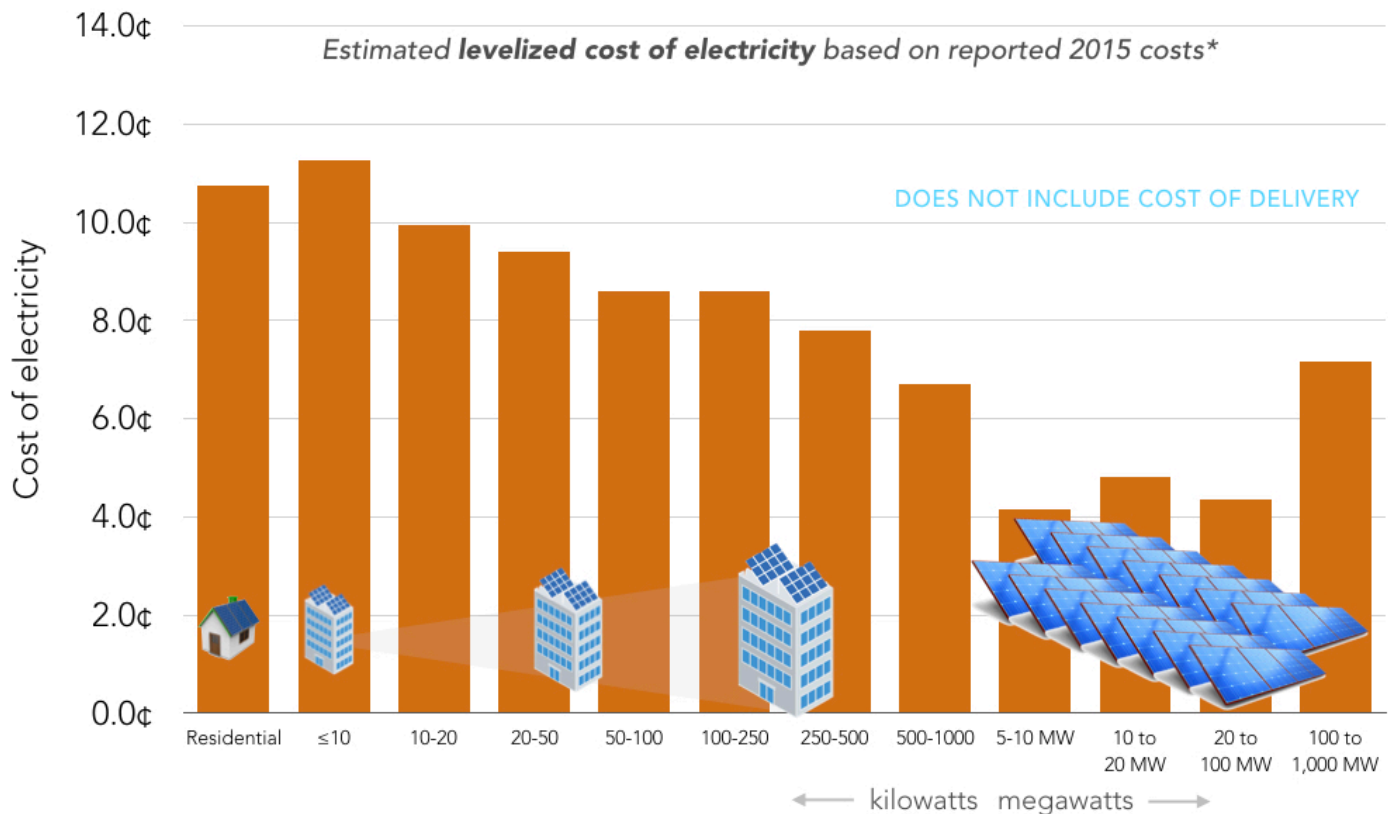
A Missing Piece: Wholesale Distributed Generation

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.

SOLAR ECONOMIES OF SCALE



Sources: Tracking the Sun IX and Utility-Scale Solar 2015
(SunShot, Berkeley Labs); SAM (NREL); ILSR



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

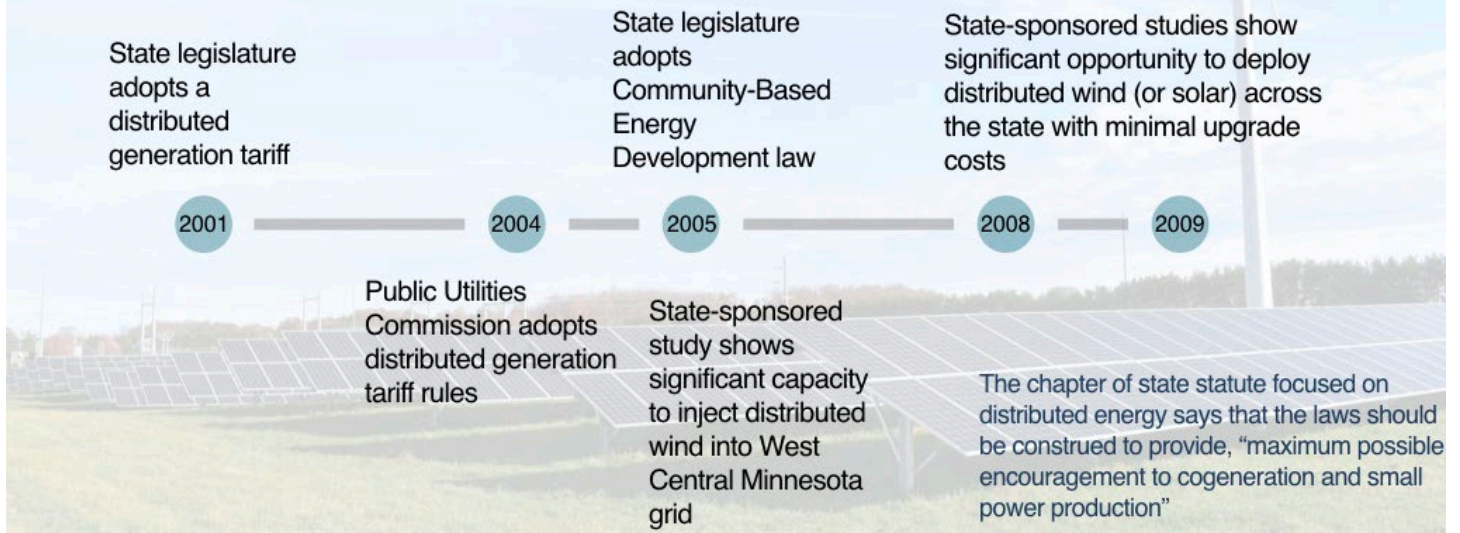
10. In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Laws 2001, Chapter 212. (PUC order, Docket 01-1023, 9/28/04). <http://bit.ly/33eLjzr>

11. Motion of the Minnesota Solar Energy Industries Association, et al. (Docket 01-1023, 3/23/18). <http://bit.ly/3d1Clon>

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>

TIMELINE OF MINNESOTA'S WHOLESALE DISTRIBUTED GENERATION EFFORTS



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

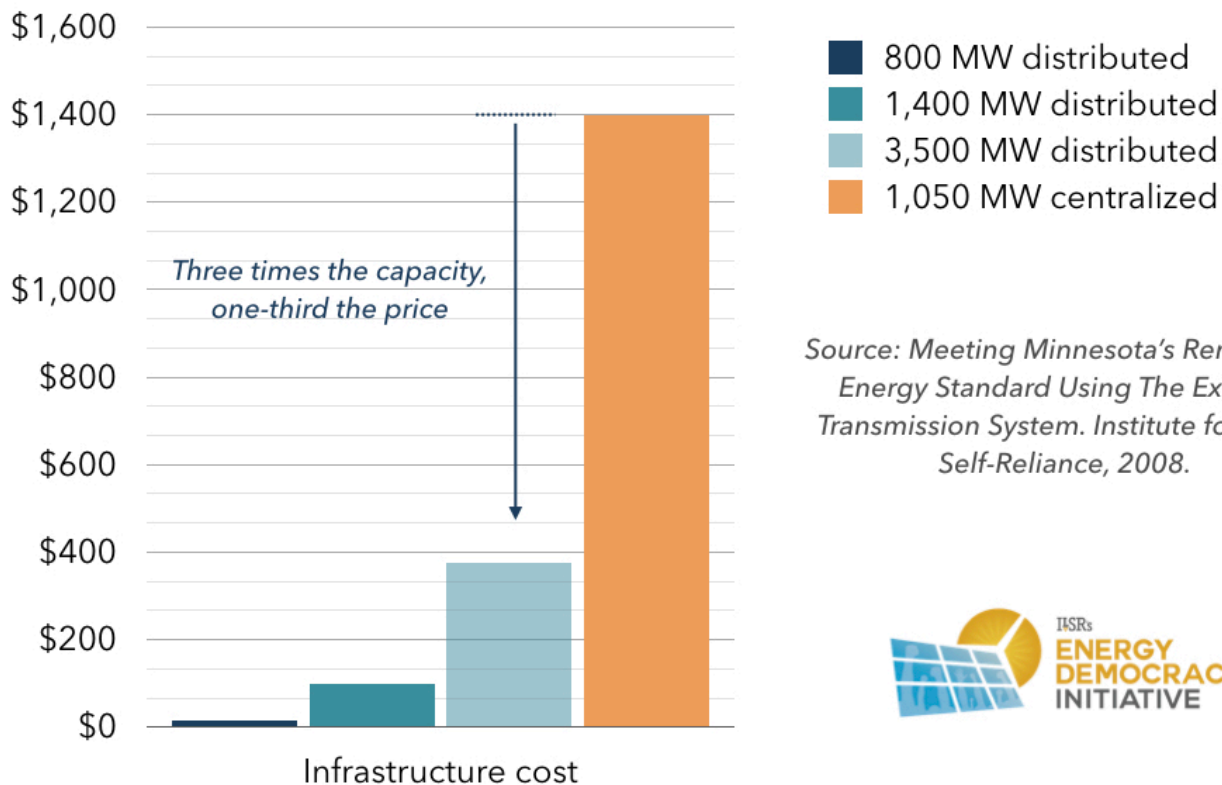
The study examined only an on-peak scenario, not off-peak energy delivery, but it is illustrative of the potential for significant integration of distributed energy resources. To the extent these sweet spots still exist, projects could materialize using the lapsed Distributed Generation Tariff or PURPA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

Distributed wind projects versus centralized high-voltage transmission upgrade



Source: Meeting Minnesota's Renewable Energy Standard Using The Existing Transmission System. Institute for Local Self-Reliance, 2008.



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.

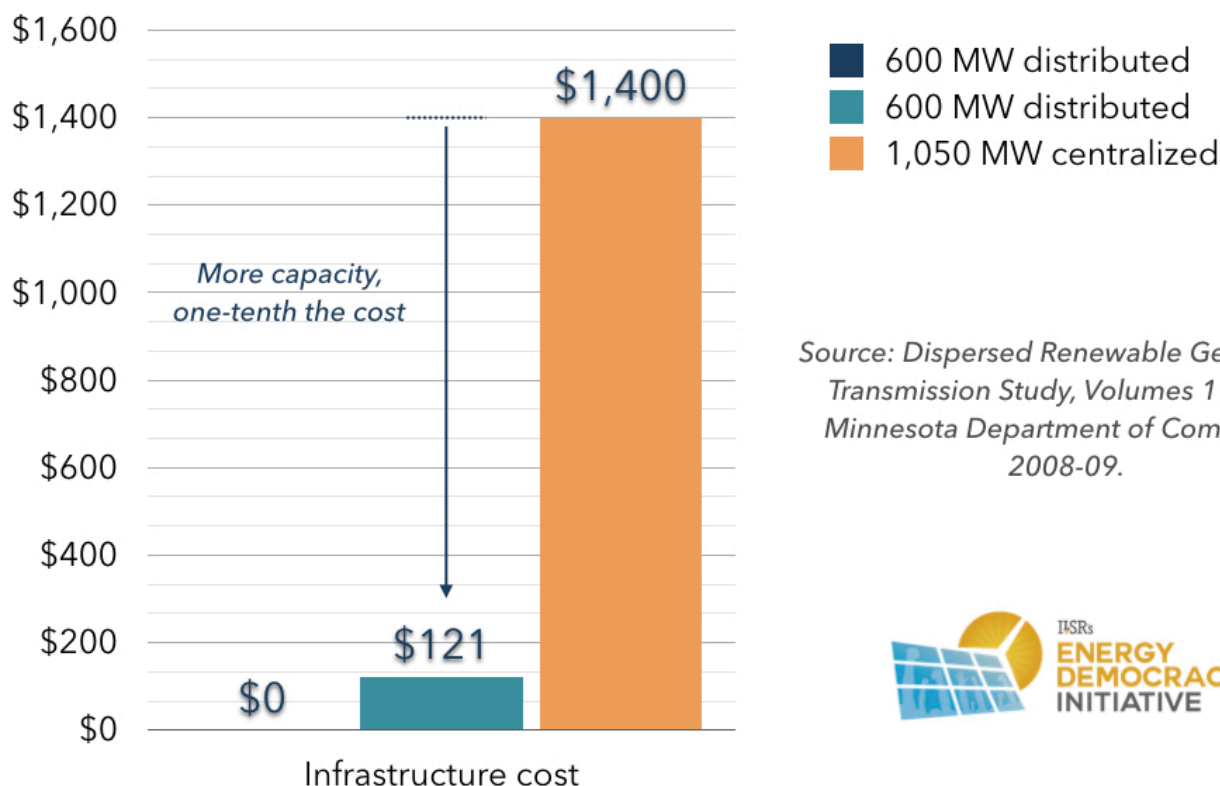
Follow-up Studies Support the First

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



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://legalelectric.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. Dukeclarity 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						CONTRACT YEAR	NON-LEVELIZED RATES
	2019	2020	2021	2022	2023	2024		
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)

	<u>On-Peak Energy Prices (¢/kWh)</u>		<u>Off-Peak Energy Prices (¢/kWh)</u>	
	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>
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.

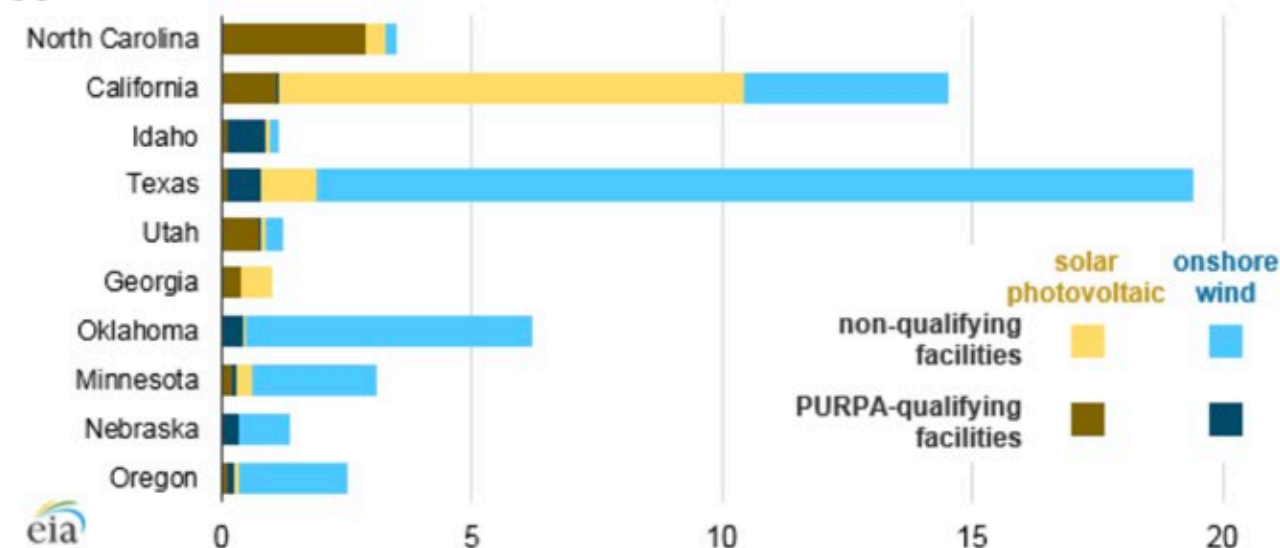
Georgia, another state that has seen significant PURPA development, also has avoided cost data available for public inspection. For Georgia Power, the state’s dominant electric provider, avoided cost projections are **published** in GPSC Docket No. 4822. Michigan regulators also recently revisited their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

Top ten states with PURPA-qualifying facility generating capacity additions (2008-2017)
gigawatts

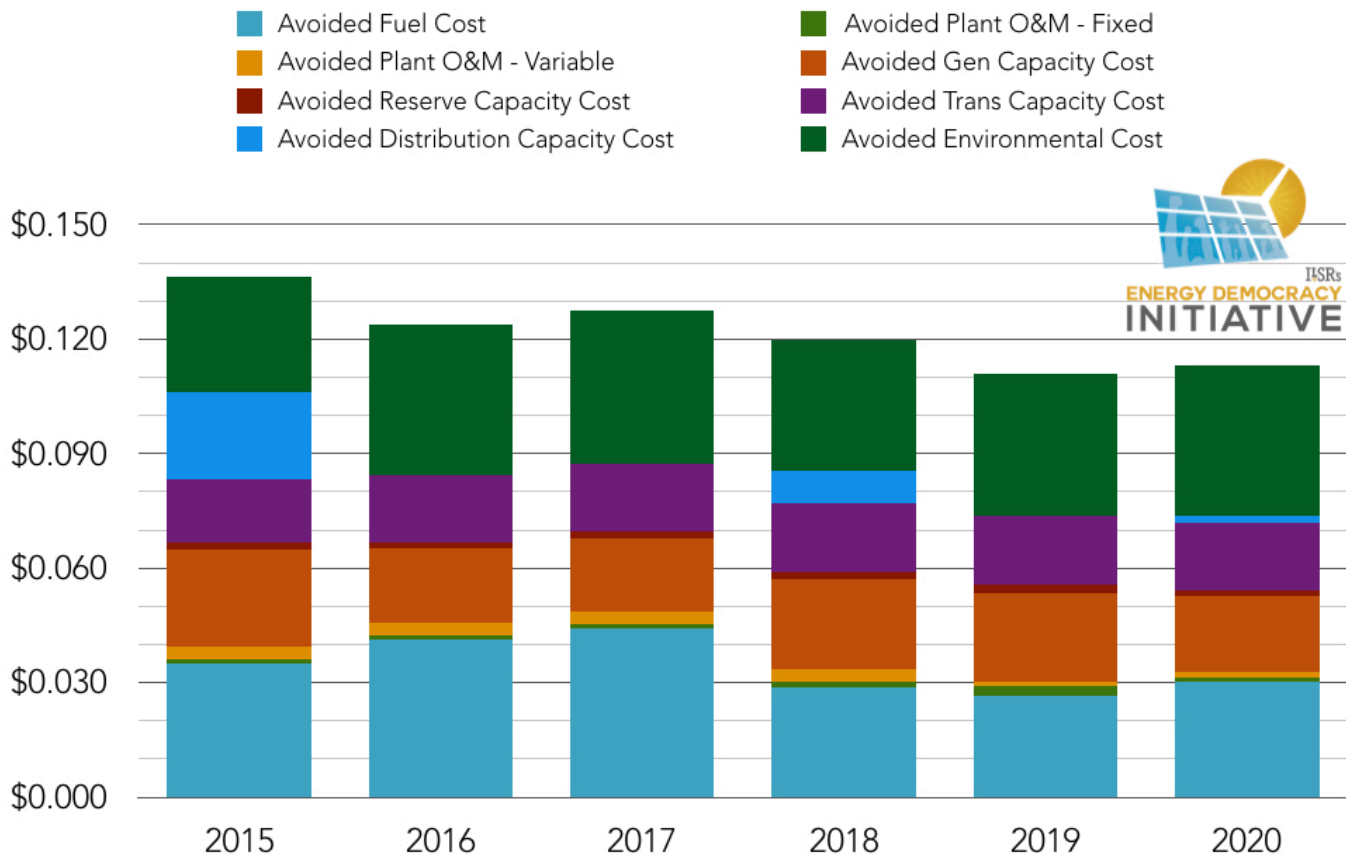


While PURPA might not be the main driver of renewable energy deployment, it's still been important in several states. And worth noting, most of the top states in PURPA deployment have a common theme: publicly available avoided cost pricing.

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 lower 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 Williams 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 scheduled³¹
- 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 Naïm 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"