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REGULATORY ASSISTANCE PROJECT

Smart Rate Design for Distributed Energy Resources

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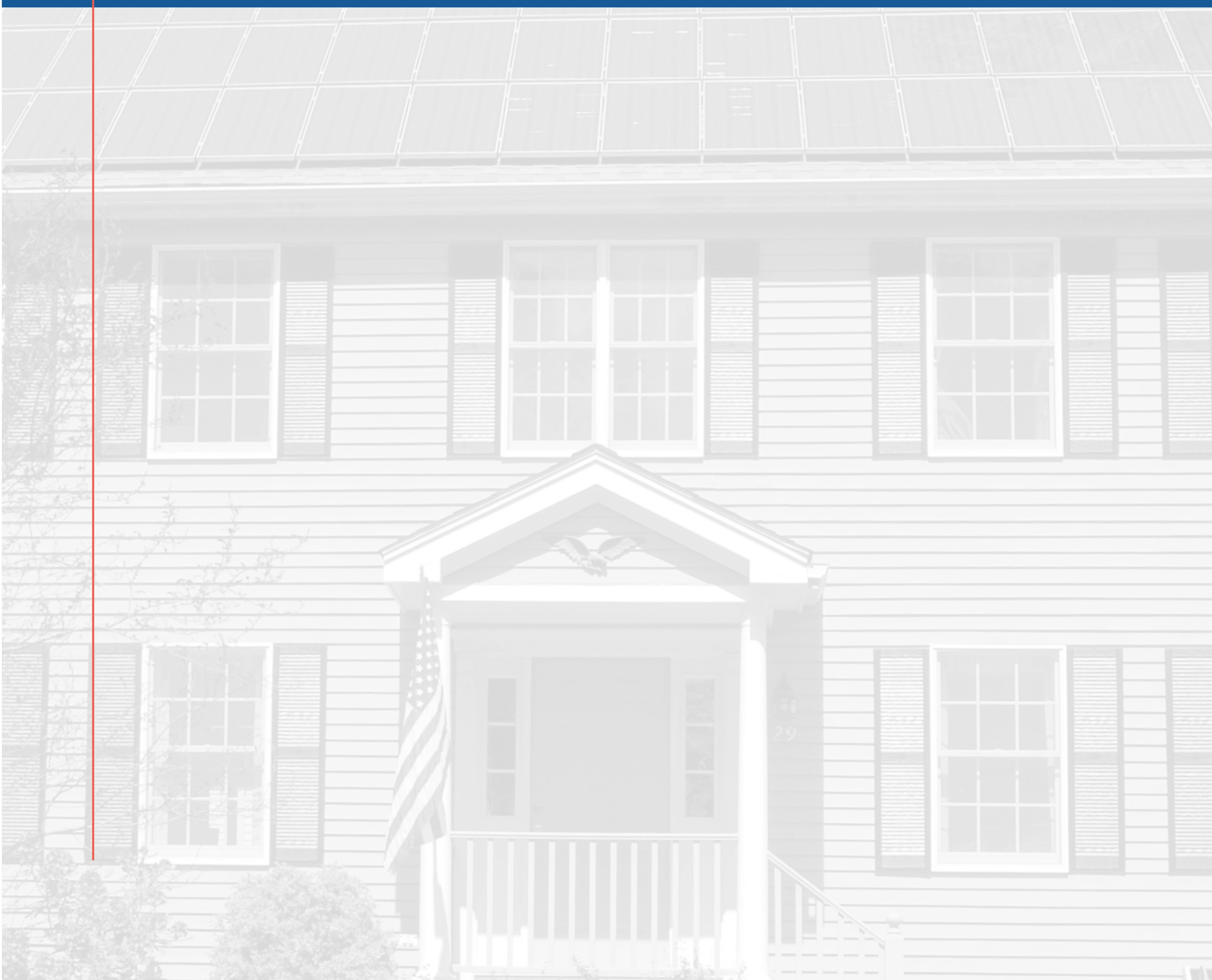

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Acknowledgments and Scope

The authors are grateful for the invitation from Chair Scripps, Commissioner Peretick and Commissioner Phillips to write this report, as well as for the generous support, assistance and wisdom of the staff of the Michigan Public Service Commission, including Julie Baldwin, Michael Byrne, Kevin Krause and Nick Revere. We extend our appreciation to the stakeholders who contributed their time, energy and ideas to the stakeholder meetings and written comments.

Thanks to John Shenot and Rick Weston from RAP for their contributions to the report as well. Donna Brutkoski and Ruth Hare provided editorial assistance.

The purpose and high-level guidance for this report was established in the February 4, 2021, Order in Michigan Public Service Commission Case No. U-20960. The specific subject matter direction is: “a thorough exploration of how customer-owned generation and energy storage are changing the way energy customers use the grid, cost allocation, and pros and cons of various rate design options, and may include recommendations for the Commission’s consideration.” As further described in this report, additional motivation included the developments of the MI Power Grid initiative, Michigan Senate Resolution 142 and the potential for legislative changes. As readers will note, the following report qualitatively considers at length the topics requested by the Public Service Commission and SR 142 but, instead of any one recommendation on rate design reform, provides alternative pathways to consider. Additional quantitative work will be necessary to decide upon or implement new rate designs. Furthermore, this report does not provide any legal advice or specific recommendations for statutory changes.

1. Introduction

The electricity system is evolving rapidly in the United States. Across many dimensions, modern technology and data are expanding the capabilities of utilities, customers and other participants in the energy system. These capabilities allow for new opportunities to lower system costs and new pathways to cost-effectively achieve policy goals, such as economic development, equity, resilience and emissions reductions. In particular, the cost of distributed energy resources (DERs), such as clean distributed generation (DG), battery storage and energy management technologies, has declined substantially over the past two decades, and many jurisdictions have seen rapid development of DER technologies at customer sites, such as solar photovoltaic (PV) systems.

To harness these capabilities, regulatory structures have to keep up, including cost allocation and rate design. Many regulatory methods from the last century were choices of convenience because of limitations that may no longer hold. Even many best practices from the 20th century were based on assumptions about the electricity system that are no longer true. These practices include the traditional methods for embedded cost allocation, such as spreading demand-related costs over a very small number of system peak hours. These demand-related costs are then typically converted into simple individual noncoincident peak (NCP) demand charges for many commercial and industrial (C&I) customers and simple volumetric kWh rates for residential customers. In both cases, the pricing mechanism disregards the underlying proposition that those costs are driven by shared system peaks and would be better reflected in time-differentiated pricing.[1] Historically, attempts to develop more sophisticated methods to allocate demand-related costs were limited by data availability, and time-differentiated pricing required metering that was either unavailable or expensive. Neither of these limitations holds any longer.

Net metering with monthly netting — a simple billing mechanism for DG, often primarily solar PV — has existed in some jurisdictions since the early 1980s. This framework is understandable for customers and easy for utilities to implement. As long as the number of customers using this mechanism was small, the issues presented to utilities and other customers were necessarily small as well. As penetration rates grew, however, issues around fair pricing and cost allocation, as well as system design and operation, began to spring up in the jurisdictions with the highest levels of distributed solar PV adoption.[2] Furthermore, jurisdictions with high penetrations of any one resource type can face declining marginal benefits for that resource.[3] Although improved planning can address

[1] More generally, the rate design that best matches cost causation will not always precisely match the relevant cost allocator because of data, metering and billing limitations.

[2] At the end of 2020, Michigan ranked 32nd out of 50 states in megawatts of distributed solar PV at 98.9 MW, according to the U.S. Energy Information Administration. For further details, see Section 2.C and Appendix A.

[3] For example, while solar PV can help enormously with system constraints in the early afternoon, its value is much more limited in the evening. Relatively high levels of solar PV have, in fact, pushed net system peaks from afternoon times to the evening in Hawaii and California. For generation resource adequacy purposes, this effect is the same whether the solar PV is interconnected at the transmission or distribution level. With more balanced resource development, however, including more diversified solar panel orientations, this may not occur, and in the long term this could also be counteracted by new sources of load.

some of these issues, evolving the compensation mechanisms for distributed energy resources, including net metering, is an important piece of the puzzle.[4]

Reducing cost shifts (see the text box on Page 42 for a discussion of definitions of cost shifting) and equitably allocating costs between DER adopters and nonadopters is one goal of needed changes to rate design and DG compensation mechanisms. Such changes, however, including those that are specifically applied to certain kinds of DER customers, do not solely need to focus on that issue. Improvements to rates, particularly to reflect the time-based nature of many system investments and operational costs, can also:

- Give good economic signals to customers to align a customer's financial incentives for investment and operation with the benefits that are provided to the electric system and society.
- Increase the value of DERs that are adopted by using them to reduce short- and long-term system costs and provide resilience to customers.
- Provide benefits related to electric vehicles (EVs), such as the encouragement of vehicle charging at times that are relatively good for the system and provision of low-cost fueling that could help boost EV adoption.
- Improve the cost causation basis of cost allocation for all customers and reduce cost shifting more broadly.

These improvements can be pursued because, in large part, metering and billing capabilities limited historic rate designs to simple options, and those simple options could be considered efficient price signals only in a very broad sense. Michigan now has the advantage of two major investor-owned electric utilities with advanced metering infrastructure for all residential and small commercial customers, which enables a wide range of potential reforms.

In Michigan, net metering for distributed generation has already evolved into the inflow/outflow model as a part of the DG program, first established in 2018 in Case No. U-18383 and then implemented in subsequent rate cases. Like any new framework, the inflow/outflow model has its pros and cons as a replacement for traditional net metering. Under this framework, inflows from the grid and outflows to the grid are metered separately, and inflows can be charged a rate that is different from the credits applied to the outflows. As approved in Michigan, the import rate is now set at the normal retail rate for the customer class, and the outflow credit is set by the power supply rate. With these parameters, the inflow/outflow model leads to higher contributions from participating DG customers to all electric system costs compared with the previous net metering framework, as long as customers do not change their usage patterns to avoid exporting. The advantage of this change is that these customers are clearly not avoiding payment for their use of the grid, a common criticism of simple monthly net metering

[4] Numerous reports on reforms to net metering and distributed generation compensation have been published in the last decade. Notable examples include: NARUC Staff Subcommittee on Rate Design. (2016). *Distributed energy resources rate design and compensation*. National Association of Regulatory Utility Commissioners. https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0; and Stanton, T. (2019). *Review of state net energy metering and successor rate designs*. National Regulatory Research Institute. https://pubs.naruc.org/pub/A107102C-92E5-776D-4114-9148841DE66B/

frameworks. This substantially reduces the likelihood of material cost shifting. The inflow/outflow model can also be applied to a wide variety of underlying rate designs, such as time-varying rates and demand charges. Questions remain, however, about this model: Do customers understand how to manage their bills, and, if they do, does the model provide efficient price signals?

In October 2019, the Michigan Public Service Commission (MPSC) established the MI Power Grid initiative, in conjunction with the office of Governor Gretchen Whitmer, seeking to help integrate new clean energy technologies and optimize grid investments for reliable, affordable electricity service.[5] The initiative has proceeded on three tracks: (1) customer engagement, including innovative rate offerings, (2) integrating emerging technologies and (3) optimizing grid investments and performance. On September 29, 2020, the Michigan Senate adopted Senate Resolution 142 “to encourage the Michigan Public Service Commission to undertake a study into alternative and innovative rate design options for Michigan’s electric customers.”[6] Senate Resolution 142 also specifies a list of rate design options to consider in the study, all of which we discuss in this report.[7]

In the December 2020 order in the Consumers Energy rate case, the MPSC opined generally on the need to examine a more comprehensive set of rate design options for DERs.[8] In an order on February 4, 2021, the MPSC explained this background, created the Distributed Energy Resources Rate Design working group under the MI Power Grid initiative and described the process for this report.[9] A stakeholder meeting was held March 9, 2021, and an outline for this report was issued on April 6, 2021.[10] The draft report was issued for public comments on September 2, 2021, and a stakeholder meeting occurred on September 8, 2021.[11]

Further rate design reforms are almost certainly needed so that DERs can fulfill their promise as a key part of the grid of the future in Michigan. These reforms will inevitably involve complex and sensitive trade-offs, where no one solution will be optimal with respect to each and every rate-making principle and policy goal. The highest-level principles of rate-making and the broader policy goals of utility regulation are informative

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[5] See generally Michigan Public Service Commission. (n.d.-a). *MI Power Grid*. https://www.michigan.gov/mpsc/0,9535,7-395-93307_93312_93593---,00.html

[6] Michigan Legislature, Reg. Sess. 2020, Senate Resolution 142, (MI 2020). http://www.legislature.mi.gov/documents/2019-2020/resolutionadopted/Senate/pdf/2020-SAR-0142.pdf

[7] The nonexclusive list in Senate Resolution 142 includes customer charges, fixed system access charges, demand charges, standby charges and time-of-use rates.

[8] Michigan Public Service Commission, Case No. U-20697, Order on December 17, 2020, p. 324. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000HwkkyAAB

[9] Michigan Public Service Commission, Case No. U-20960, Order on February 4, 2021. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000J8TH5AAN

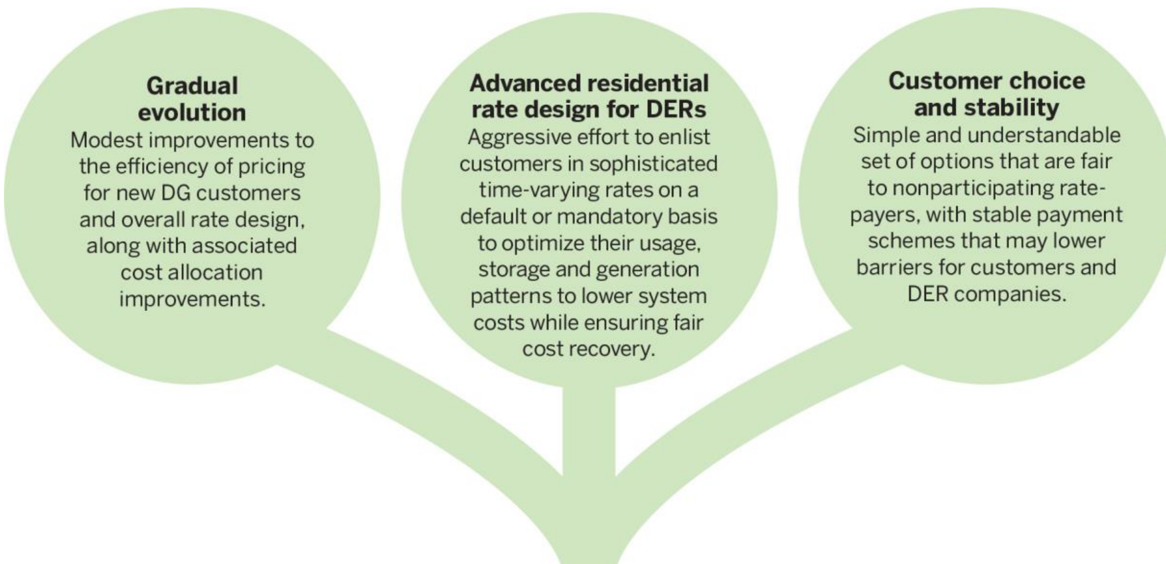
[10] Feedback on a draft outline and presentations from stakeholders were part of the March 9, 2021, stakeholder meeting. In addition, written comments on the draft outline were submitted by DTE Electric, Consumers Energy, Tom Stanton and Alain Godeau.

[11] Written comments were received from MPSC staff as well as eight individual or joint submissions from stakeholders: (1) 5 Lakes Energy, (2) Association of Businesses Advocating Tariff Equity, (3) Consumers Energy, (4) DTE Electric, (6) the Great Lakes Renewable Energy Association, (5) the Michigan Environmental Council, (7) the Michigan Energy Innovation Business Council and Advanced Energy Economy and (8) the Joint Clean Energy Organizations — the Ecology Center, the Environmental Law & Policy Center, the Solar Energy Industries Association, Vote Solar and the Union of Concerned Scientists.

but do not provide specific answers to our modern issues with DER rate design. When we are trying to understand this complex area of policy, there are important linkages between concepts that are sometimes discussed separately: (1) electric system cost causation and efficient marginal cost pricing, (2) benefit-cost tests and (3) cost allocation frameworks. Many of these concepts involve two more fundamental questions: (1) What is a given resource worth? (2) How are electric system costs fairly split among all electricity customers? Understanding these relationships in detail should help to illuminate stakeholders' concerns with existing rate structures and to chart a productive path to the future.

This report catalogs the key complexities to consider and then lays out the multitude of potential program structures and different rate design options, before sketching out high-level potential paths for residential customers,[12] summarized in Figure 1.

Figure 1. Three potential rate design pathways for distributed energy resources



[12] Although this report focuses on residential customers, nearly identical recommendations would apply to small business customers. Larger commercial and industrial customers are different in some significant interrelated ways, notably with respect to increased sophistication, higher bills and the ability to hire professional energy management. Individually, they make up a higher percentage of usage at different levels of the system such that their actions may pose additional risks to system planning and operation. For further discussion and recommendations in the California context for larger C&I customers, see Linvill, C., Lazar, J., Dupuy, M., Shipley, J., & Brutkoski, D. (2017). *Smart non-residential rate design*. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-non-residential-rate-design/. As a general matter, RAP recommends that rate designs for medium and large C&I customer classes with major demand charges could be reformed to include a mix of wholesale energy market pricing, time-of-use and critical peak pricing for other shared system costs and more narrowly designed demand charges. To the extent that a new DG program compensation structure includes compensation for environmental value in exchange for RECs, C&I customers with eligible distributed generation technologies should be able to choose that option as well. It is also relevant that, under currently typical rate designs, there is little concern with cost shifting due to adoption of DG by medium and large C&I customers.

In more detail, the three high-level paths are:

- Gradual evolution:
    - New customers who adopt DG would be required to be on a year-round time-varying rate but otherwise keep the key elements of the current inflow/outflow model. These customers would be placed on a time-of-use (TOU) rate by default but could opt into other year-round time-varying rates.
    - In the next rate case for each utility, the default TOU rate for these customers could be redesigned, and tiered customer charge adders to recover site infrastructure costs[13] could be introduced for all residential customers.
    - Existing net metering and DG program customers could remain on the same rate structures as the rest of their customer class but, as with current policy, could also choose among different optional rates.
    - Incremental administrative costs and new processes would be minimal, although additional analyses and cost allocation reforms could be helpful to implement rate design improvements.
- Advanced residential rate design for DER customers:
    - A broad category of residential customers, including all customers with DG, storage, EVs and high usage, would be moved to an advanced marginal cost-based rate design on a default or mandatory basis. Other residential customers would remain on a simpler basic rate.
    - The advanced residential rate would include a seasonally varying multiperiod TOU rate with critical peak pricing, as well as a demand charge for site infrastructure and a distribution flow charge[14] on all imports and exports.
    - For customers who elect to export to the grid, export credit structures would also be based on marginal cost, and the environmental component could vary by technology. The inflow/outflow structure would be replaced by netting within each pricing period.
    - Several different new analyses and processes would be necessary to set the different elements of the new rate and credit structures, as well as analysis to ensure a reasonable expectation that the revenue requirement can be recovered.

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[13] The term “site infrastructure” encompasses the final equipment connecting customers to the broadly shared electric system, including service lines, line transformers and secondary voltage lines.

[14] A symmetric kWh charge on both imports from and exports to the distribution grid, as further discussed in Sections 5.A and 6.

- Customer options and stability:
  - New DG customers would have a choice between two rate structures. Existing net metering and DG program customers could remain on their current rates but would have the ability to opt into one of the new options.
  - Choice A would be a buy-all/credit-all tariff.
    - A buy-all rate would be the same as what other, non-DER customers pay.
    - DG customers would have a separate production meter, and all production would be credited at a value-based flat rate that is locked in for 20 years.
  - Choice B would be a variation on traditional net metering.
    - The inflow/outflow structure would be replaced with monthly netting.
    - The rate for net imports would be the same as the typical residential rate, with the credit for net generation set at the same administrative values as Choice A above.
    - These customers would have a grid access charge based on installed capacity, the revenues of which would be split between public benefits programs and distribution system costs.
  - New processes and analyses would be necessary to set administrative credit values and the grid access charges.

These three paths are designed to illustrate how different tariff approaches perform relative to different regulatory principles and policy objectives, which will clarify key trade-offs. This report provides a qualitative evaluation of these three pathways on four primary criteria:

- Fair cost allocation.
- Efficient customer price signals to use, generate and store energy.
- Customer understanding and acceptance.
- Administrative feasibility.

In the end, a new program structure and new rate design(s) for DERs could be a blend of elements from each of these three pathways, and different elements from each could be adopted over time.

2. Background and Regulatory Context in Michigan

A. Overview of Electricity Market Structure and Utility Regulation

The current market structure and basic practices for electric utility regulation in Michigan form an important context to understand the role of distributed resources generally but also more specifically serve as important underlying factors in electric system cost causation, which in turn is important for both cost allocation and efficient pricing. Since 1909, the Michigan Public Service Commission — originally the Michigan Railroad Commission and then the Michigan Public Utilities Commission — has had the authority to regulate electric rates and conditions of service for its jurisdictional investor-owned electric utilities,[15] of which there are currently seven.[16] In designing retail electric rates, the MPSC is guided by the statutory standard that rates should be "equal to the cost of providing service to each customer class" and that "each class … is assessed for its fair and equitable use of the electric grid."[17]

Although the MPSC has substantial regulatory authority over its jurisdictional electric utilities and their retail rates, the Midcontinent Independent System Operator (Midcontinent ISO or MISO) has certain responsibilities over wholesale energy markets, transmission and certain aspects of reliability planning.[18] Michigan's seven investor-owned electric utilities do not directly own transmission assets but rather use the transmission owned by independent transmission companies[19] that are overseen by MISO, which is regulated by the Federal Energy Regulatory Commission (FERC). These seven utilities do own both generation and distribution assets. In the case of distribution assets, the MPSC has exclusive regulatory authority, but authority is shared in certain respects with MISO for generation. The MPSC does retain authority over generation resource adequacy, integrated resource planning and certificates of necessity for large generation investments or purchased power agreements. When the MPSC exercises its authority over generation for the investor-owned utilities, several important statutory requirements should be kept in mind:

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[15] These are sometimes referred to as rate-regulated electric utilities to distinguish from cooperatives, where the MPSC has lesser regulatory authority, and municipal utilities, where the MPSC has very little regulatory oversight.

[16] Consumers Energy, DTE Electric, Alpena Power Company, Indiana Michigan Power Company (I&M), Upper Peninsula Power Company (UPPCO), Upper Michigan Energy Resources Corporation (UMERC) and Xcel Energy (Northern States Power Company — Wisconsin).

[17] Michigan Compiled Laws, Section 460.11. Although this specific statutory language is unique to Michigan, this language represents general principles that most utility regulators follow. This section also provides guidance on cost allocation for production and transmission costs, senior citizen and low-income rates, and rates for schools, colleges and universities.

[18] I&M's service territory in southwest Michigan is covered by PJM instead of MISO.

[19] The corporate parents of two jurisdictional investor-owned utilities do own transmission assets in Michigan: American Electric Power (owners of I&M) and Xcel. Many transmission assets in the rest of the state were previously owned by jurisdictional investor-owned utilities but were sold after restructuring.

- The statutory renewable portfolio standard of 15% by 2021 and the statutory goal of 35% renewable energy and energy efficiency by 2025.[20]
- The integrated resource planning statute, which requires equal consideration of supply- and demand-side resources as well as a shared savings framework.
- The energy waste reduction statute, which results in each utility having a 1% annual electric savings target.[21]

Under Public Act 286 passed in 2008, Michigan electric customers are allowed to choose an alternative electric supplier. These customers no longer pay the generation supply charge regulated by the MPSC, but rather pay a rate agreed upon between the customer and alternative electric supplier. The overall customer choice program for each utility is capped at 10% of average retail sales, thus limiting the number of customers who can participate.[22] In addition, electric utilities are required to offer voluntary green pricing programs to customers.

Last, apart from state-jurisdictional net metering policies and retail rate designs, there are federally required compensation opportunities for certain kinds of energy resources in Michigan. The Public Utilities Regulatory Policies Act of 1978 (PURPA) requires utilities to sign long-term contracts with qualifying facilities (primarily small renewable and cogeneration units) at an avoided cost rate.[23] These PURPA contracts may include, but are not limited to, generation resources connected at the distribution level. Second, as issued in 2020 and clarified in 2021, FERC Order 2222 has created a framework for distributed energy resources to participate in organized wholesale markets, including MISO.[24]

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[20] Governor Whitmer's MI Healthy Climate Plan executive orders also related goals pertaining to clean energy and reductions in electric sector greenhouse gas emissions. Michigan Department of Environment, Great Lakes, and Energy, Office of Climate and Energy. (n.d.) *Climate*. https://www.michigan.gov/climateandenergy/0,4580,7-364-98206---,00.html

[21] Michigan Public Service Commission. (n.d.-b). *Energy waste reduction*. https://www.michigan.gov/mpsc/0,9535,7-395-93308_94792---,00.html

[22] Michigan Public Service Commission. (n.d.-c). *Electric customer choice*. https://www.michigan.gov/mpsc/0,9535,7-395-93308_93325_93423_93501_93509---,00.html

[23] Michigan Public Service Commission. (2020, April 20.) *Report on the implementation of the Public Utility Regulatory Policies Act of 1978 (PURPA).* https://www.michigan.gov/documents/lara/PURPA_Report_FINAL_04202020_with_appendices_688003_7.pdf

[24] The Order 2222 compliance approach for MISO is currently under development. Midcontinent Independent System Operator. (2021, September 8). *Distributed energy resources (DER) — FERC Order 2222 Compliance IR070.* https://www.misoenergy.org/stakeholder-engagement/issue-tracking/distributed-energy-resources/

B. History of DER Compensation Policies and Rate Design Reforms

In Michigan, net metering was first established by Public Act 295 of 2008.[25] For small DG projects (20 kW or less), this meant monthly netting and credit rollover between billing periods at the full retail rate, referred to statutorily as "true net metering." Larger projects (above 20 kW) were instead eligible for "modified net metering," where credits were defined as the power supply portion of the retail rate.[26] In 2016, Public Acts 341 and 342 required the replacement of the legacy net metering frameworks with a new DG program. The statutory requirements for the new program included a study by the MPSC on "an appropriate tariff reflecting the equitable cost of service for customers who participate in a net metering program or distributed generation program."[27]

The process for creating the new DG program took multiple steps, including: (1) an interim DG program established shortly after the 2016 laws took effect,[28] (2) an MPSC staff report filed in February 2018,[29] (3) a framework order establishing the key aspects of the program in April 2018[30] and (4) implementation in rate cases filed after June 2018.[31] See the text box beginning on the next page for a discussion of the new program's billing and crediting framework.

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[25] Prior to 2008, the utilities and the MPSC had established a "negotiated" net metering arrangement.

[26] Since the creation of the new distributed generation program, the previous true net metering and modified net metering are collectively referred to as the legacy net metering programs.

[27] Michigan Compiled Laws, Section 460.6a(14). Although the inflow/outflow billing method was chosen under this legal standard, it is possible that other billing methods and rate structures could meet this standard as well.

[28] Michigan Public Service Commission, Case No. U-18383, Order on July 12, 2017. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001UYJbAAO. The interim distributed generation program largely tracked the substance of the legacy net metering programs, with the limitation that the new customers may only remain on those rates for 10 years from their date of enrollment.

[29] Michigan Public Service Commission Staff. (2018, February 21). *Report on the MPSC staff study to develop a cost of service-based distributed generation program tariff* (Case No. U-18383). https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000016WftAAE

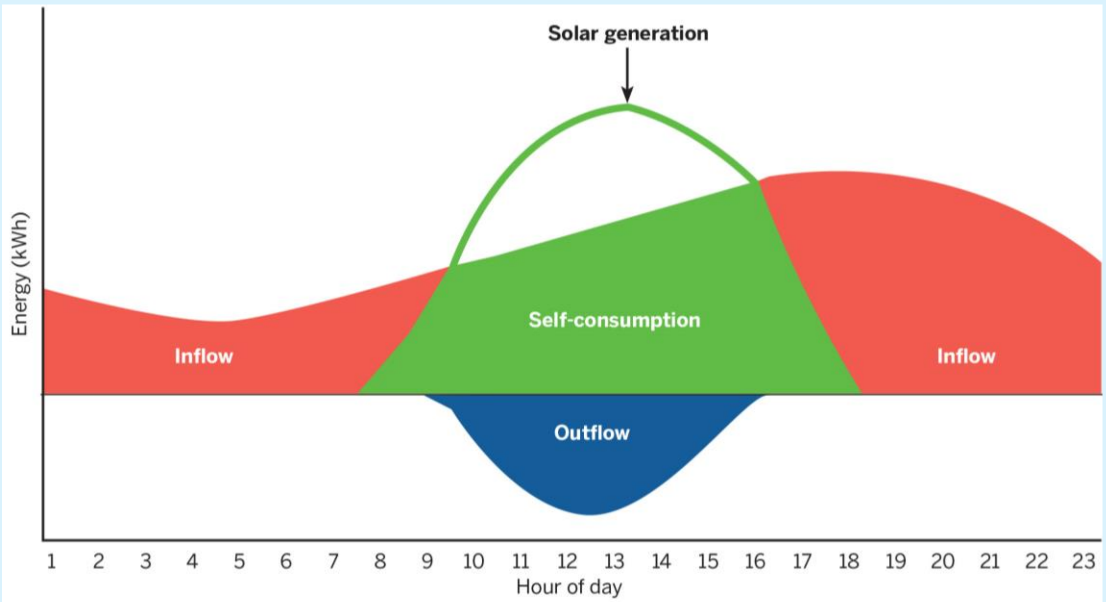
[30] Michigan Public Service Commission, Case No. U-18383, Order on April 18, 2018. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000022KiuAAE

[31] For DTE Electric and UPPCO, the commission rate case order approving the new DG program tariffs was issued in May 2019, and DG program enrollment began in the same month. For I&M, the approval order came in January 2020, and enrollment began in February 2020. For Consumers Energy, the approval order came in December 2020, and enrollment began in January 2021. Alpena Electric and Xcel have both recently filed rate cases that include a DG program tariff, which are currently under review. It is unknown when UMERC will file a rate case that includes a DG program tariff.

The Michigan inflow/outflow framework

The key feature of the new DG program is replacement of monthly netting with separate measurement and billing of inflow, meaning kWh delivered *from* the distribution system, and outflow, meaning kWh delivered *to* the distribution system.[32] Figure 2 depicts the difference between inflow, outflow and self-consumption for an illustrative residential customer with solar PV.[33]

Figure 2. Illustrative load and generation curve for residential customer with rooftop solar PV



Adapted from Beach, T., & McGuire, P. (2013). *Evaluating the Benefits and Costs of Net Energy Metering in California*

Inflow is charged at the relevant retail rate, while outflow is only credited at the supply portion of the retail rate, and two of the four electric utilities with approved DG program tariffs exclude transmission costs when calculating this portion of the credit. At the end of the billing period, the total monetary value of credits earned from outflow is subtracted from the customer's retail rate charges (e.g., a customer charge and inflow charges and a demand charge for some classes) to determine the final bill amount. Outflow credits typically can only be applied to a portion of the bill,[34] and any unused credit value can be rolled over to the next billing period. The inflow/outflow framework is administratively feasible and has substantial flexibility to be applied to nearly any rate structure. For example, residential DG program customers are allowed to opt into time-of-use rates just like any other residential customer.[35] Inflow and outflow are then measured and priced separately for each period in the TOU rate.

When credit values for outflows are lower than retail rates for inflows, the inflow/outflow model typically leads to higher bills for participating customers than monthly netting structures used in traditional net metering. Such a change can be evaluated on its own merits for its potential impacts on DER development, whether customers and DER providers can estimate financial costs and benefits with reasonable certainty, and the extent to which it improves the fairness of cost allocation. Detailed customer data are certainly helpful for customers and DER providers, but education on new rate structures can take time.

For customers who can understand the structure of this model, however, the inflow/outflow framework presents new incentives for the adoption of and specific operating patterns for energy storage and management technology, as well as more general changes to load patterns. For customers with distributed generation on non-time-varying kWh rates, the differential between higher inflow rates and lower outflow credits creates a financial incentive to self-consume more energy by shifting consumption (or charging a battery) to coincide with times when they are exporting energy. This is because additional outflows are only worth the power supply rate (which is forgone by lowering exports), and a reduction in inflows saves a customer the full retail rate. Thus, customers benefit from the difference between the full retail rate and the power supply rate when they shift 1 kWh of consumption from a time with inflow to a time with outflow. If solar PV is the DG technology in question, customers have an incentive to shift consumption from mornings, evenings and overnight to daytime hours when the sun is shining. Such a shift may or may not be in the best interest of the electric system. That could depend on whether the times when the system is constrained typically occur during sunny afternoons (as in many jurisdictions traditionally) or in the evening (e.g., in jurisdictions with high solar penetrations that are experiencing a so-called duck curve). When TOU rates or other complex pricing structures are introduced in addition to the inflow/outflow model and asymmetric inflow rates and outflow credits, the entire rate structure should be examined to understand a customer's incentives.

All of these issues are worth considering as a part of the overall evaluation of pathways forward and whether to keep the inflow/outflow framework or adopt other innovations instead. Of course, each potential alternative has its own pros and cons as well on the crucial dimensions of fair cost allocation, efficient customer price signals, customer understanding and administrative feasibility. Furthermore, the inflow/outflow structure can also be used more selectively as a rate design feature, such as billing for nonbypassable charges based on inflows, as has been adopted in New Hampshire.

By statute, participation in the legacy net metering and DG programs is limited to 1% of average in-state peak load for the preceding five years. The utilities that have approached or reached their limit have raised this cap, however, either through a rate case settlement with other parties or a voluntary agreement with the MPSC.[36] Eligible technologies for these programs include solar PV, wind, hydroelectric projects and methane digesters,

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[32] This billing and pricing framework is sometimes referred to as instantaneous netting. Generation consumed instantaneously on site is effectively compensated at the full reduction in retail billing determinants. This is different from "buy-all/credit-all" arrangements where none of the gross generation is treated as a reduction in retail billing determinants. Section 4 of this report further discusses these alternative metering and billing frameworks. In addition, for some utilities' larger C&I rates, customers with demand charges can be credited based on kW outflow, analogous to a reverse demand charge.

[33] Adapted from Beach, T., & McGuire, P. (2013). *Evaluating the benefits and costs of net energy metering in California*. Crossborder Energy. http://large.stanford.edu/courses/2015/ph240/tran1/docs/beach.pdf

[34] For most of the utilities, credits can only be applied to the generation portion of the bill. This restriction can either be thought of as part of the rollover rules or else as a minimum bill defined by the distribution charges.

[35] There are utility implementations of the net metering program where participating customers could also opt into TOU rates but could only use credits earned in one time period in that same period in subsequent billing months (e.g., credits earned during an on-peak period can only be applied to usage in subsequent on-peak periods).

[36] UPPCO doubled its program size cap to 2% of its peak load as part of a rate case settlement approved in May 2019 and further agreed to increase its program size to at least 3% as part of a settlement in case No. U-20995. Consumers Energy notified the MPSC that it would increase its program size cap to 2% on December 21, 2020.

although the vast majority of the installed capacity participating in the program has been solar PV to date. DG projects under these programs are categorized by size:

- Category 1: 20 kW and under.
- Category 2: between 20 kW and 150 kW.
- Category 3: methane digesters over 150 kW and up to 550 kW.

The program caps have been divided among these three categories, with Category 1 typically limited to 50% of the overall cap, 25% for Category 2 and the remaining 25% for Category 3.

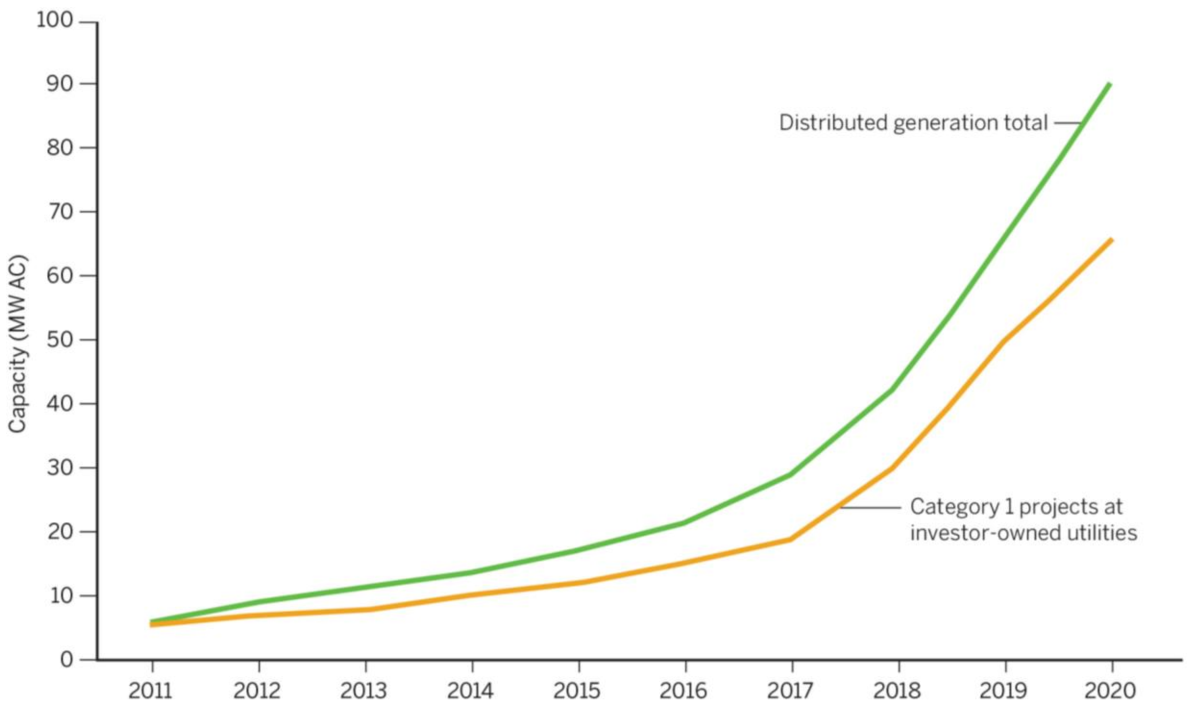
In addition, the MPSC, along with Consumers Energy and DTE Electric, has been working to take advantage of the capabilities provided by advanced metering infrastructure with new rate design options. Starting in June 2021, residential customers for Consumers Energy no longer have a year-round flat kWh rate option and are placed on the summer peak rate by default, with a higher on-peak rate from 2 p.m. to 7 p.m. on weekdays from June through September. Consumers Energy also provides other time-varying options for residential customers. DTE does still have a non-time-varying inclining block kWh rate for residential customers by default but provides several time-varying options to residential customers, including a relatively simple time-of-day rate and a more complex dynamic peak pricing rate.[37] These innovations are designed to better align rates with cost causation and have the additional benefit of fairer and more efficient cost allocation within rate classes. Only the generation supply portion of these rates varies by time and season, which may provide additional opportunities for rate design innovation with respect to the distribution rate.

[37] DTE customers in the distributed generation program are not currently allowed to opt into the dynamic peak pricing rate.

C. Statistics on DER Adoption

Michigan has seen steady growth in distributed generation adoption over the past decade, as shown in Figure 3.[38]

Figure 3. Distributed generation adoption in Michigan overall and in small-scale projects



Data sources: Michigan Public Service Commission distributed generation, net metering and solar program annual reports

This trend has been particularly driven by accelerating growth in Category 1 DG projects over the past several years. Table 1 on the next page shows the Category 1 DG capacity from 2016 through 2020 for all seven investor-owned utilities and midyear data for the three utilities from which it is available.

[38] Data in Figure 3 and Tables 1 and 2 come from Michigan Public Service Commission distributed generation, net metering and solar program annual reports for 2011 to 2020 available here: https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94933---,00.html

Table 1. Category 1 distributed generation capacity for investor-owned utilities (in kW)

	2016	2017	2018	2019	2020	July 2021*
Alpena	70	76	91	89	89	
Consumers Energy	3,444	5,967	12,429	22,447	32,489	39,721
DTE Electric	10,165	11,841	16,727	24,560	30,178	35,700
I&M	238	470	672	1,041	1,519	
UMERC	267	279	292	303	307	
UPPCO	729	734	734	1,124	1,309	1,488
Xcel	4	19	25	25	24	
Total	14,917	19,386	30,970	49,589	65,915	76,909

* The report for 2020 includes midyear 2021 data for three utilities.

Data sources: Michigan Public Service Commission distributed generation, net metering and solar program annual reports

On a capacity basis, these projects are overwhelmingly located in the Consumers and DTE service territories, Michigan's two largest investor-owned utilities by far. As shown in Table 2, there is significant adoption in the UPPCO service territory as well, as measured against the five-year average of in-state peak load (the relevant metric for the DG program caps).

Table 2. Category 1 DG capacity as percentage of five-year average of in-state peak load

	2016	2017	2018	2019	2020	July 2021*
Alpena	0.11%	0.12%	0.14%	0.14%	0.14%	
Consumers Energy	0.05%	0.08%	0.17%	0.30%	0.43%	0.53%
DTE Electric	0.09%	0.11%	0.15%	0.22%	0.27%	0.32%
I&M	0.04%	0.07%	0.10%	0.16%	0.23%	
UMERC	0.14%	0.14%	0.15%	0.15%	0.16%	
UPPCO	0.54%	0.54%	0.54%	0.83%	0.97%	1.10%
Xcel	0.02%	0.07%	0.10%	0.10%	0.09%	

* The report for 2020 includes midyear 2021 data for three utilities.

Data sources: Michigan Public Service Commission distributed generation, net metering and solar program annual reports

The MPSC has also begun working with the electric utilities to collect data on DG program customer adoption of battery storage. Table 3 on the next page shows a snapshot of battery storage capacity.[39]

[39] Michigan Public Service Commission Staff. (2021, October). *Distributed generation program report for calendar year 2020.* https://www.michigan.gov/documents/mpsc/MPSC_Staff_DG_Report_Calendar_Year_2020_737505_7.pdf. Calculation of capacity per customer by the Regulatory Assistance Project.

Table 3. Battery storage adoption by DG program customers at end of 2020

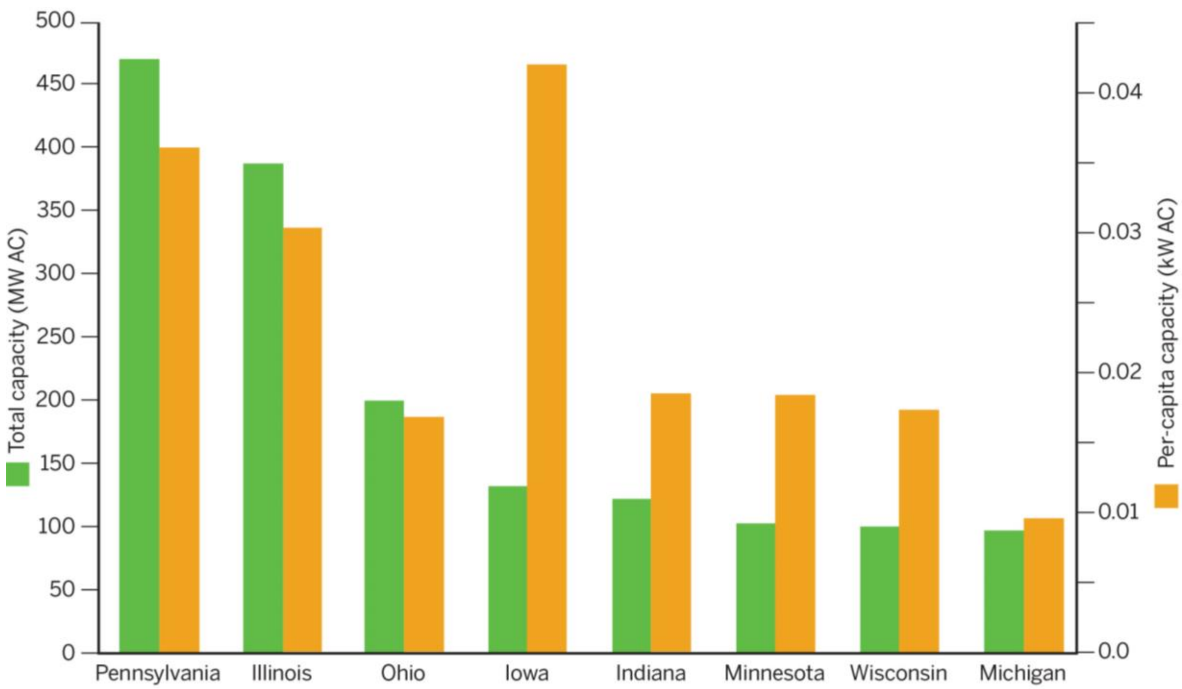
	Customers	Storage capacity (kW)	Capacity per customer (kW)
Consumers Energy	147	757	5.15
DTE Electric	615	3,408	5.54
I&M	7	38	5.43
Total	769	4,203	5.47

Data source: Michigan Public Service Commission Staff. (2021, October). *Distributed Generation Program Report for Calendar Year 2020*

Although DG and DER adoption in Michigan has been growing, the state still ranks toward the bottom nationally in distributed solar PV adoption, according to 2020 data from the U.S. Energy Information Administration. In overall capacity, Michigan ranks 31st out of 51 jurisdictions. In capacity per capita, Michigan is 41st. See Appendix A for more details.

Regionally, Michigan also ranks toward the bottom in distributed solar PV, whether measured in the aggregate or per capita. Figure 4 shows a comparison with other states.[40]

Figure 4. Distributed solar generation in selected states at end of 2020



Data sources: U.S. Energy Information Administration. (2021). *Form EIA-861M (Formerly EIA-826) Detailed Data;* U.S. Census Bureau. (2021, April 26). *2020 Census Apportionment Results*, Table 1

40 Data sources: U.S. Energy Information Administration. (2021). *Form EIA-861M (formerly EIA-826) detailed data.* https://www.eia.gov/electricity/data/eia861m/; U.S. Census Bureau. (2021, April 26). *2020 Census apportionment results*, Table 1. https://www.census.gov/data/tables/2020/dec/2020-apportionment-data.html. Additional calculations by the authors.

Factors influencing DER adoption

Numerous financial and nonfinancial considerations can influence DER adoption levels. Much of the focus in policy discussions is on the financial aspects of an individual decision to adopt DER, but personal considerations that are not directly financial can be important too.

There is a long list of policies that go into the direct financial benefits that a customer who adopts DERs can reasonably expect. That list includes retail rate design structures, tax policies and other state and federal policies, such as renewable portfolio standards. Each of these areas has its own set of considerations, which can be complex. For example, rate design for DERs is a matter of dollars and cents, but the understandability of the rates and the potential for future changes can be important to customers as well. Similarly, there are complications related to the structure of available tax incentives, which can be determinative. For example, storage is currently eligible for the federal investment tax credit only if it is paired with and charged by a renewable energy source.[41]

In addition, a wide range of costs are incurred by a customer adopting DERs, or by their installer, whose costs are ultimately passed on to the customer as well. DER hardware costs (e.g., solar panels and batteries) have been dropping rapidly, but labor costs, customer acquisition and marketing, and permitting are independent of hardware costs. In addition, customer-specific electrical upgrades, interconnection costs and other fees can be significant in many cases.

Customers can also receive other benefits from adopting DERs, although such benefits can be indirectly financial as well. One example is backup power during outages, which may be available for solar PV only under certain electrical configurations under current standards. Many participating customers may also be motivated by more general societal and community benefits, such as improving public health, mitigating climate change impacts or working directly with local DER providers to support the local economy.

Many customers do not have the option to install certain DERs at their residence because they are renters, live in multifamily housing or have a shaded roof.

D. History and Future Directions for the Electric System and Regulation

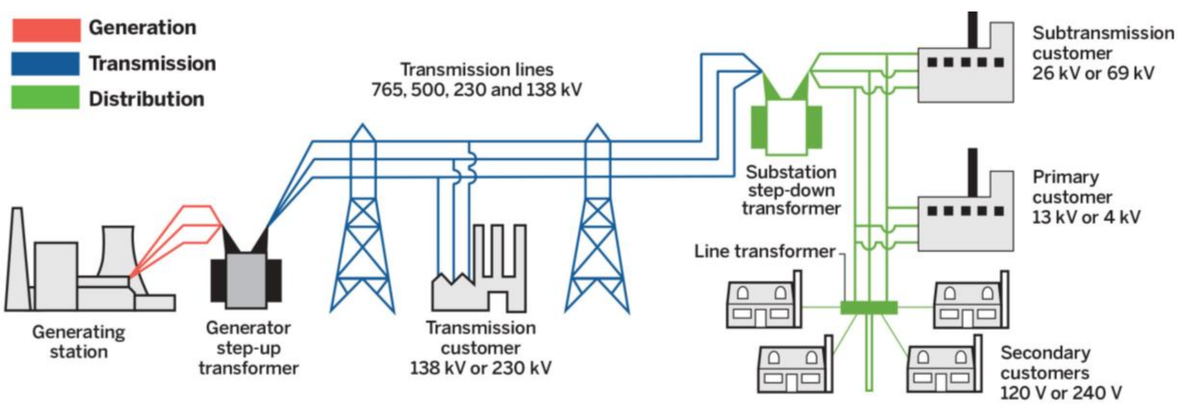
In the United States, the electric power system has undergone significant developments every few decades since it was first created in the late 19th century. An initial period of unrestrained private utility development, primarily in cities, was followed by the establishment of state regulation of franchised monopolies in the 1910s and 1920s. In the 1930s and 1940s, the Federal Power Commission (now FERC) was granted new authority, the major interstate electric conglomerates were broken up, and significant federal efforts were undertaken to ensure access to electricity service across the country. In the 1970s, escalating fuel prices due to international oil crises and the availability of new generation technologies sparked major new capital investments and introduced the possibility of competition at the wholesale level. In the 1980s and 1990s, PURPA implementation and integrated resource planning was followed by wholesale market development and restructuring of electric utilities in many parts of the country. In the 2000s, due to innovative drilling and extraction techniques, such as hydraulic fracturing, the cost of

[41] EnergySage. (2021, September 16). *Solar battery incentives and rebates.* https://www.energysage.com/energy-storage/benefits-of-storage/energy-storage-incentives/

fossil gas declined and domestic production increased sharply, which in turn led to major increases in electricity generation from gas. These major trends shaped the U.S. electricity infrastructure and regulatory systems. As change continues, learning and adaptation must be continuous to meet energy needs in an efficient and increasingly sustainable manner.

Figure 5 illustrates how the electric system was conceptualized and organized for much of the 20th century.[42] Large central generators were the source of electric energy and connected to the transmission grid. While a few very large industrial customers took service directly at transmission voltages, nearly all customers were served at the lower voltages that defined the electric distribution system. On the distribution system, some customers took service at the primary voltage level and either used specialized equipment that operated at that voltage or owned their own transformers to convert the electricity to the correct voltage. However, all residential customers and nearly all small commercial customers took service at secondary voltage, where a line transformer may serve anywhere from one customer in extremely rural areas to dozens of customers in an apartment building.

Figure 5. Illustrative traditional electric system



Source: Adapted from U.S.-Canada Power System Outage Task Force. (2004). Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations

Cost allocation and rate design techniques developed in this context were based on certain assumptions, including:

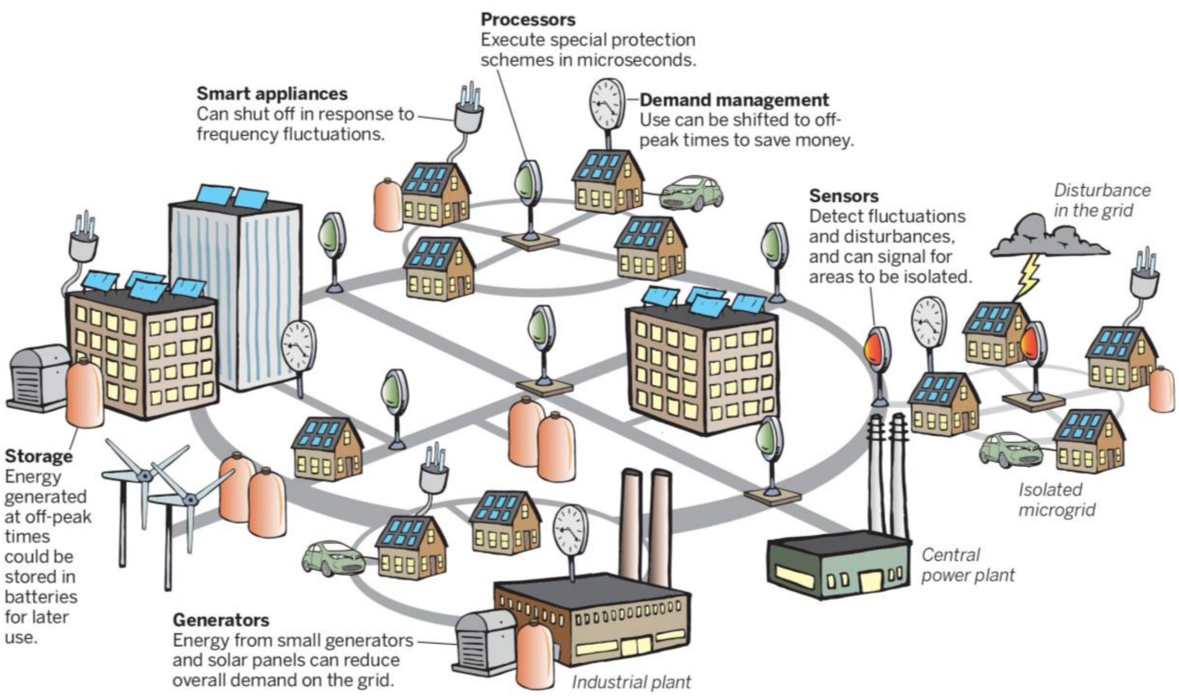
- Reliability risks focused on generation resource adequacy issues driven by the highest hours of customer usage over the course of the year.
- Little visibility and control within the transmission and distribution systems.

42 U.S.-Canada Power System Outage Task Force. (2004). *Final report on the August 14, 2003 blackout in the United States and Canada: Causes and recommendations.* https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf

- Metering technology that could only handle simple forms of data recording and storage.
- Little or no capability for customers to manage their usage or export energy back onto the grid.

In the 21st century, however, another fundamental set of changes has occurred. There have been major decreases in the cost of solar PV and energy storage, and major breakthroughs in other customer-side technologies. Advanced metering and smarter distribution system technologies provide better data and fine-grained control of the system. This new data can be used in a multitude of ways, including better planning and investment criteria — all the way down to more efficient transformer sizing. Furthermore, electrification of transportation and heating poses both challenges and opportunities for the electric sector.[43] The future electric grid may bear more resemblance to Figure 6, with generation and storage at consumer sites, two-directional power flows and more sophisticated control equipment for customers and the grid itself.[44]

Figure 6. Illustrative future electric system



Source: Adapted from U.S. Department of Energy. (2015). *United States Electricity Industry Primer*

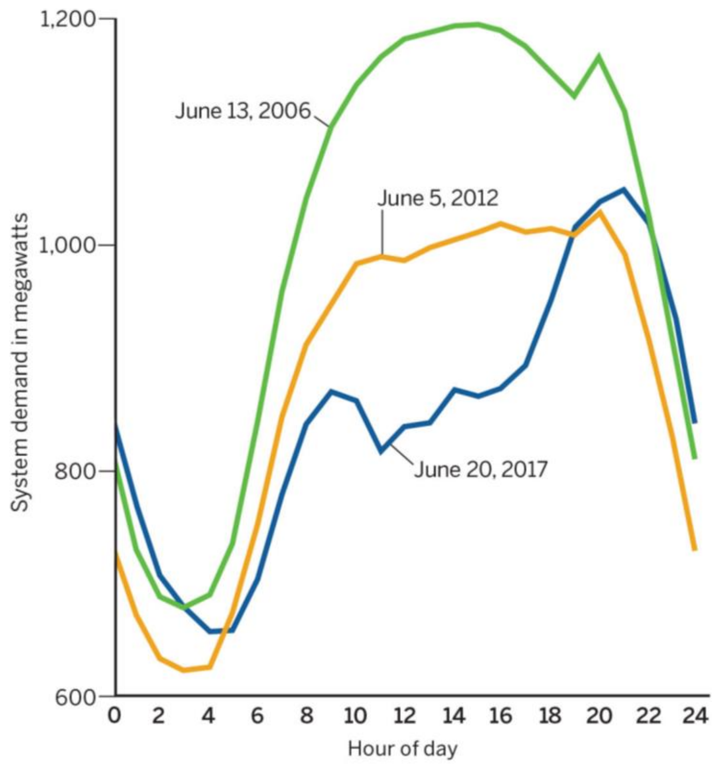
[43] See Farnsworth, D., Shipley, J., Lazar, J., & Seidman, N. (2018, June 2018). *Beneficial electrification: Ensuring electrification in the public interest.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/beneficial-electrification-ensuring-electrification-public-interest/

[44] Adapted from U.S. Department of Energy. (2015). *United States electricity industry primer* (DOE/OE-0017). https://www.energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industryprimer.pdf

Although elements of this potential future for the electric system can be sketched out at a high level, there are many key uncertainties that will be resolved only by observing innovations as they develop, along with policy decisions at every level of government. One important example is how the generation resource mix will evolve over time. In several states with high levels of solar development, a distinctive new load shape has developed,[45] as shown in Figure 7 for Hawaii.[46]

Changes like these have implications for how the electric system is planned, operated and regulated, which is discussed further below with respect to cost causation. One key planning implication is that generation resource adequacy risks may no longer be highest at the times of peak gross customer usage. Instead, as shown in Figure 8 on the next page, the concept of net load — which subtracts out nondispatchable resources, notably solar PV and wind but conceptually including some other resources as well — becomes key. In the case of generation resource adequacy, all nondispatchable resources connected to the system are relevant, not just nondispatchable technologies that are net metered or connected to the distribution system.

Figure 7. Evolution of system load in Hawaii on typical June weekday

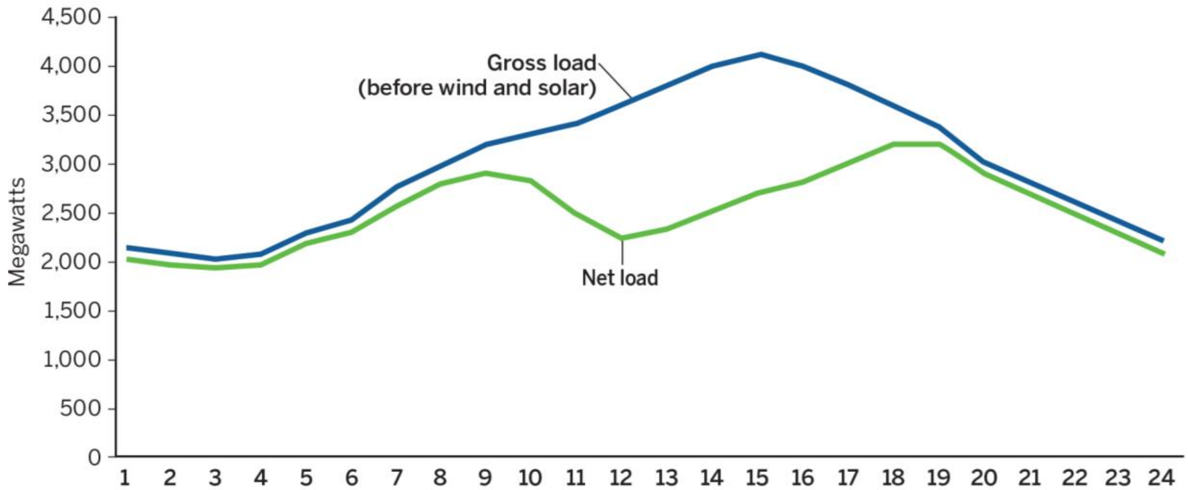


Data source: Federal Energy Regulatory Commission. (n.d.) *Form No. 714 — Annual Balancing Authority Area and Planning Area Report*

[45] This pattern for solar development is particularly distinctive if the vast majority of solar installations are all south-facing, thus increasing the correlation of production for these resources. A variety of policies in many jurisdictions incentivize the maximization of kWh production, which logically leads to south-facing panel orientations. Policies that better reflect system values could lead to different panel orientation choices, such as west or southwest orientation or panel tracking. This would lead to a somewhat different pattern of solar development.

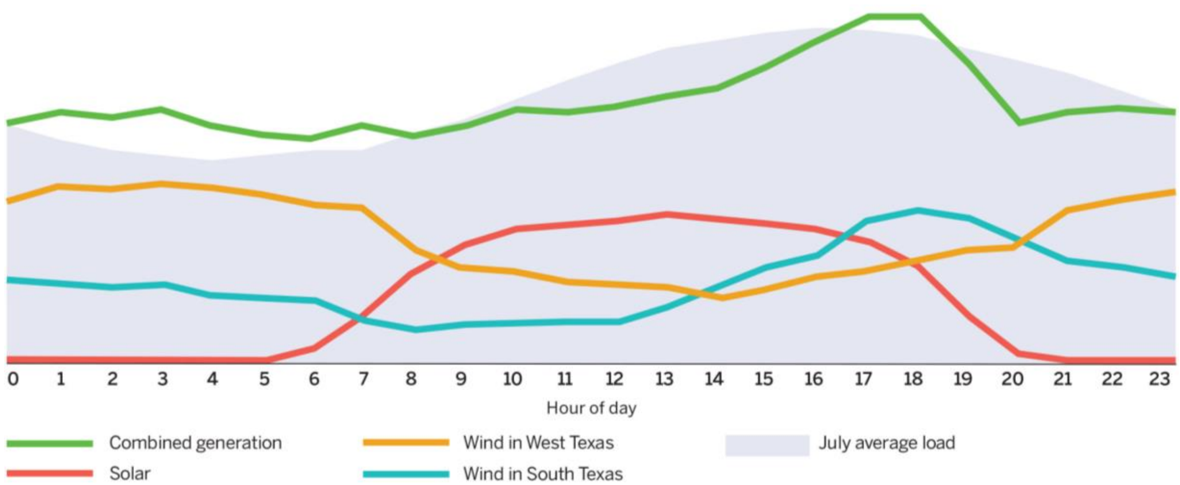
[46] Federal Energy Regulatory Commission. (n.d.). *Form No. 714 — Annual balancing authority area and planning area report*. https://www.ferc.gov/docs-filing/forms/form-714/data.asp

Figure 8. Illustrative net load curve



There are many other possible outcomes for the evolution of the generation resource mix, however. For example, it is possible that a balanced mix of wind and solar development could roughly match overall system load shape, as demonstrated in Figure 9.[47]

Figure 9. Illustrative Texas wind and solar resource compared with load shape



Sources: Adapted from Slusarewicz, J., and Cohan, D. (2018). Assessing Solar and Wind Complementarity in Texas [Licensed under http://creativecommons.org/licenses/by/4.0]. Load data from Electric Reliability Council of Texas. (2019). *2018 ERCOT Hourly Load Data*

[47] Adapted from Slusarewicz, J., & Cohan, D. (2018). Assessing solar and wind complementarity in Texas. *Renewables: Wind, Water and Solar (5)7*. https://jrenewables.springeropen.com/articles/10.1186/s40807-018-0054-3. Load data from Electric Reliability Council of Texas. (2019). *2018 ERCOT hourly load data* [Data set]. http://www.ercot.com/gridinfo/load/load_hist/

In contrast to Figure 8, the resource development pattern shown in Figure 9 would likely require fewer changes to grid operation and planning, at least in the near term.

In the last several years, states across the country have established regulatory initiatives to take advantage of these trends and avoid potential negative consequences by creating an electricity system that is more flexible, competitive, customer-friendly and sustainable. With its MI Power Grid initiative, the MPSC has taken several steps down this path as well and will have additional opportunities to harness these trends for the benefit of all of Michigan's residents.

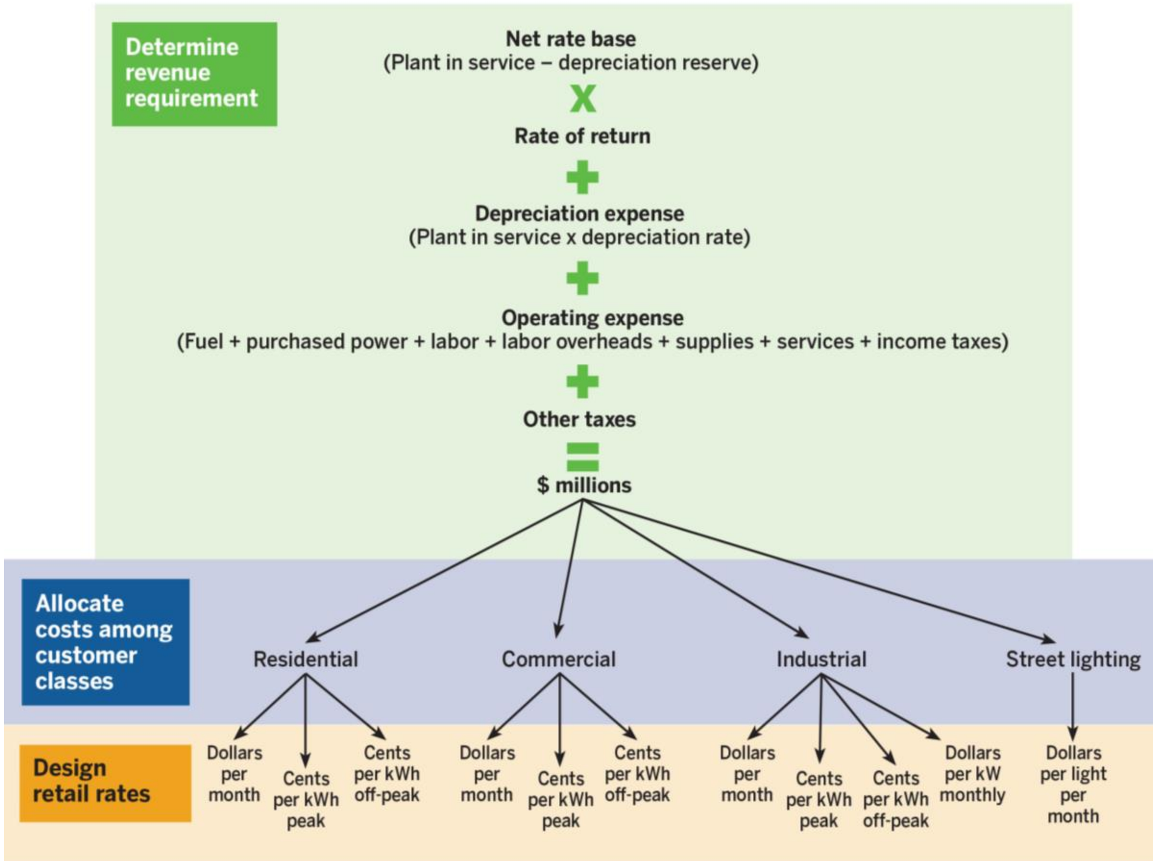
3. Rate-Making Practices and Perspectives on Costs and Benefits

Before digging into the options for reform of DER rate design and related cost allocation reforms, it is worth reviewing basic rate-making principles that have been relied upon for decades as well as historical and evolving ideas about electricity system costs and their proper allocation. It is also important to acknowledge the changing demands being placed on the electricity system and the evolving public policy goals that now influence utility actions and regulators' decisions, including in the areas of cost allocation and DER rate design.

A. Traditional Rate-Making Process and Principles

In traditional economic regulation of electric utilities, regulators review rates proposed by utilities and issue orders to determine just and reasonable rates. In the regulation of prices for utility service, the prevailing practice is to develop separate sets of prices for a small and easily identifiable number of customer classes. Examples of customer classes include residential, general service and street lighting. For many utilities, general service (commercial and industrial) customers are divided into multiple classes, often based on size thresholds or the distinction between secondary voltage service and primary voltage service. For a given utility and its service territory, all customers in each class are typically eligible for the same set of default and optional tariffs, under which all customers pay the same prices. This price is typically the same for each customer within a class regardless of the customer's location within a service territory, a practice known as postage stamp pricing. As shown in Figure 10 on the next page, the prices for each class are typically developed in three high-level steps: (1) determination of the revenue requirement, (2) allocation of costs between customer classes and (3) final design of the retail rates. For each step, data collection and tracking — with respect to utility costs of all kinds, customer usage and behavior and energy resources — is an important foundational element of rate-making.

Figure 10. Simplified rate-making process diagram for electric utilities



The annual revenue requirement is set based on the cost of service, a technical term that typically includes operating expenses, depreciation expense (a measure of the annual loss in value of utility capital assets) and taxes, as well as an explicit element for a rate of return on net rate base. Environmental and public health externalities are not directly included in the cost of service, although a range of compliance costs and program expenditures are motivated by these underlying concerns.

In the process of setting the rate structure, a term that combines the cost allocation and rate design steps, regulators and stakeholders refer to a wide range of principles or guidelines, many lists of which have been compiled by past analysts.[48] Many of these principles are still useful today, though it is also worth asking how changing circumstances

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[48] The most famous of these are the Bonbright principles from Bonbright, J. C. (1961). *Principles of public utility rates.* Columbia University Press. https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/. On Page 291, Dr. Bonbright lists eight frequently cited principles but immediately explains that "lists of this nature are useful in reminding the rate maker of considerations that might otherwise escape his attention, and also useful in suggesting one important reason why problems of practical rate design do not readily yield to 'scientific' principles of optimum pricing. But they are unqualified to serve as a base on which to build these principles because of their ambiguities … their overlapping character, and their failure to offer any rules of priority in the event of conflict." He goes on to discuss his preferred three criteria of "(a) the revenue-requirement or financial-need objective … (b) the fair-cost-apportionment objective … and (c) the optimum-use or consumer-rationing objective" (p. 292).

may affect them. Some generally accepted principles that remain helpful in today's debates regarding rate structure include:

- **Effectiveness in yielding total revenue requirements.** The utility should have an expectation that it will approximately recover its revenue requirement from customer rates, with a reasonable amount of stability from year to year.
- **Customer understanding and acceptance.** Prices should not be overly complex or convoluted such that customers cannot understand how their bills are determined or how they should respond to manage their bills. Customers and the public should generally accept that the prices they are charged for electricity service are fair for the service they are receiving.
- **Equitable allocation of costs and the avoidance of undue discrimination.** The apportionment of total costs of service among the different customers should be done fairly and equitably.
- **Efficient price signals that encourage optimal customer behavior.** On a forward-looking basis, electricity prices should encourage customers to use, conserve, store and generate energy in ways that are most efficient.

It should be noted that there may be trade-offs between these principles in many cases and the task of the regulator is to strike an overall balance in these objectives.

Utility revenue recovery issues

Effective recovery of a utility's revenue requirement is a long-standing regulatory goal. In principle, nearly any retail service can be priced to collect the right revenue levels given an expected set of billing determinants. Different rate designs can have different levels of volatility, however, leading to different relative likelihoods of over- or underrecovery. There can also be trade-offs with other regulatory objectives and policy goals. For example, rates that make revenue recovery more certain could lead to less equitable cost allocation and less economically efficient pricing. Similarly, certain types of more efficient forward-looking price signals, such as critical peak pricing, can make revenue recovery less certain.

These factors can also change over time as technology develops. Widespread availability of affordable energy storage will enable customers to manage and potentially significantly reduce their demand charges and may allow some customers to disconnect entirely. This change would make certain rate designs that have long been thought to be stable from a revenue perspective — namely, demand charges and customer charges — less certain than in the past.

Many states have adopted revenue regulation, commonly known as decoupling, as a measure that enhances a utility's revenue stability over time.[49] The Michigan Court of Appeals found in 2012 that the MPSC was not authorized to adopt a revenue decoupling mechanism for electric utilities, but new legislation could change that.[50]

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[49] Lazar, J., Weston, F., Shirley, W., Migden-Ostrander, J., Lamont, D., & Watson, E. (2016, November 8). *Revenue regulation and decoupling: A guide to theory and application (incl. case studies).* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/revenue-regulation-and-decoupling-a-guide-to-theory-and-application-incl-case-studies/

[50] *Association of Businesses Advocating Tariff Equity v. Michigan Public Service Commission*, State of Michigan Court of Appeals, April 10, 2012.

B. Policy Goals of Utility Regulation

In addition to the above rate-making principles, utility regulation has always included important policy goals, such as the prevention of monopoly pricing and customer discrimination, promotion of economic development and expansion of service. As one may expect, public policy goals are evolving and continue to add new expectations on utilities and regulators to accomplish an expanding set of objectives related to electricity service. Achieving many of these goals and objectives can be directly influenced by the cost allocation and rate setting processes that utility commissions oversee. In addition, these goals and objectives often have direct or indirect links to deployment and utilization of distributed energy resources. Thus, broad discussions about public policy goals and objectives have a legitimate role in debates around DER rate design and compensation. Policy goals that have implications for DER deployment and compensation include:

- **Competition across fuels and sectors.** One of the overarching goals of utility regulation is efficient choices of energy sources and, relatedly, allocation of resources across sectors. Although the real world never perfectly matches ideal theoretical conditions, the goal that utilities should be regulated to mimic efficient market outcomes is a worthy one. In particular, utility managers should be incentivized to operate and invest efficiently to maximize the long-run value of their company in a manner that is consistent with the public interest.

- **Competition within the electric sector.** Many policymakers and stakeholders desire increased or enhanced competition within the electricity sector to drive costs down for customers and provide more choices. Desire for greater competition has been primarily focused on electricity generation and supply in the last several decades. Independent power producers at the wholesale level can provide increased competition in generation, as can distributed energy resources. Going forward, many jurisdictions are exploring whether certain forms of competition are feasible for the delivery system, with the notable example of nonwires procurements for alternatives to traditional distribution system investments.

- **Provision of reliable service.** Reliability of electricity service has always been important, but with the advent of DERs and microgrid capabilities, service can now encompass a broader concept of customer resilience.

- **Societal equity.** Historically, regulatory goals related to equity have focused on universal access and affordability. In modern times, this concern has also evolved into the goal of equitable distribution of benefits from public policy programs.

- **Administrative feasibility.** Modest refinements to existing rules, processes and programs are simpler to adopt. In some cases, larger changes are possible but require additional time, resources and attention from relevant policymakers and stakeholders. In other cases, some theoretically possible reforms may not be feasible or may require other intermediate reforms or expenses before they could begin.

- **Clean energy and DER-focused employment.** In many states there is increasing interest in promoting employment opportunities related to distributed energy resource deployment. Jobs in the solar industry, for example, are already robust in many states and have continued to grow in recent years with the exception of 2020 due to the COVID-19 pandemic. Jobs related to installation and construction of DERs may be a policy motivator for considering ways to promote growth in these industries, including through DG compensation and rate design structures.

- **Public health and environmental protection.** For the past several decades, there have been many state and federal standards and programs to protect public health and the natural environment. Dating back to the 1970s, that includes regulation of criteria pollutants under the federal Clean Air Act, which involves a mix of federal and state responsibilities within the electric sector. In the past two decades, many states have renewable or clean energy targets in statute that require utilities to deliver a certain percentage of clean energy by specific dates. More recently, more states are adopting goals and binding requirements for utilities and other emitters to reduce greenhouse gas emissions. All of these policy drivers implicate potential changes to regulatory approaches in order to require or incentivize certain actions by utilities and customers.

Gradualism, another frequently cited principle in utility regulation, is not a policy goal or end in itself but rather an approach to problem solving and a means to achieve other regulatory objectives. With respect to DER rate design, gradualism has a strong connection to the principle of customer understanding and acceptance, the goal of avoiding disruptions to DER companies and employment and the ease of administrative implementation.

C. Cost Causation in the Electric System

The concept of cost causation is a fundamental one for both cost allocation and rate design.[51] Although it is occasionally used as a backward-looking concept with respect to cost allocation, it primarily refers to how the characteristics of utility customers collectively affect costs on a forward-looking basis. Understanding how current behavior affects current and future costs requires an understanding of the economics and engineering of the electric system. But once it is understood how costs are caused, there are straightforward arguments that (1) costs are allocated most equitably to the customers who cause them and (2) prices are most efficient if they reflect how costs are caused. In both cases, these are forward-looking marginal cost concepts.

The biggest debates around cost causation tend to focus on the allocation and pricing of capacity investments for generation, transmission and distribution.[52] The vast majority of this capacity investment is shared by large numbers of customers, and each component of

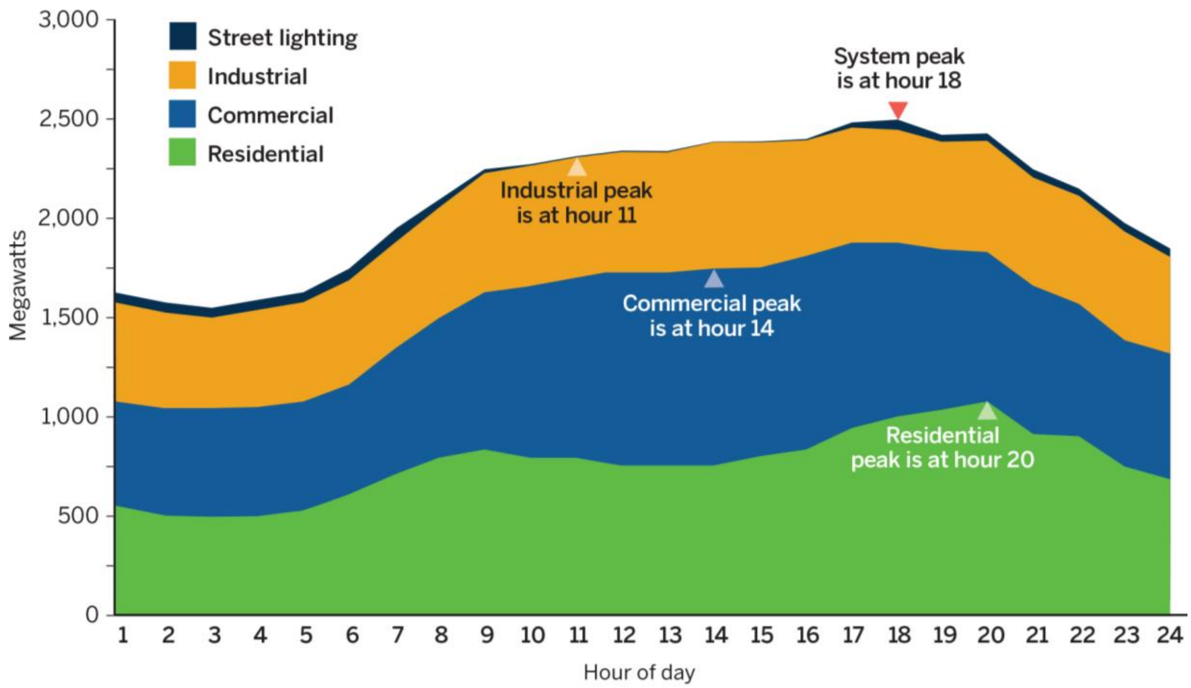
[51] For further discussion of these issues, see Section 5.1 in Lazar, J., Chernick, P., Marcus, W., & LeBel, M. (Ed.). (2020). *Electric cost allocation for a new era: A manual.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

[52] There is a persistent fallacy that fixed capacity investments mean that pricing should properly be translated into fixed charges. This is easily disproven by looking at the numerous competitive industries that involve large capital investments but use unit prices. For example, oil refineries are massive capital investments, but gasoline is still sold by the gallon. Furthermore, the concept of fixed charges in this context is sometimes applied flexibly to include both customer charges but also different kinds of demand-based charges, which can vary from billing period to billing period. The reasonableness of fixed charges, customer charges and demand-based charges (as well as their proper magnitude) turns on other issues.

this shared system is sized to meet an expected peak coincident demand of the customers it serves. Peak coincident demand for the relevant group of customers is not simply the sum of the customers' individual peak demands but is rather something less, often significantly so. This phenomenon is known as diversity of demand and reflects the temporal differences of usage across the relevant customer base.

Customer loads are diversified at every level of the utility system. At the system level, the peak is determined by that combination of customer class loads that produces the highest instantaneous demand. That system peak might or might not coincide with the peak demand of any one customer class, and that system is likely interconnected to other systems with slightly different loads through a shared transmission network. Figure 11 shows illustrative customer class loads on a system peak day. Each of the customer classes has a highest load hour at a different time: hour 11 for industrial, hour 14 for commercial and hour 20 for residential. The load for the lighting class is roughly the same across many different hours when the sun is down. The overall peak is at hour 18, which is different than any of the class peaks.

Figure 11. Illustrative load diversity at the customer class level



When similar data are examined at the level of individual customers, metrics for diversity of load are even higher. Overall, the diversity of customer load is one major reason why it is less expensive to build a shared electric system, in addition to the historic economies of scale for generation technologies.

Given these patterns of customer load, utilities and system planners need to invest to meet two primary objectives: (1) ensuring reliability (in both operational and investment time frames) and (2) meeting year-round system load at least cost. Historically, reliability concerns have risen predominantly (but not exclusively) at peak system load hours.[53] Achieving the objectives in a reasonable way requires detailed economic analysis of the different potential options that meet the relevant engineering criteria,[54] such as when analyzing the optimal mix of generation resources. Given multiple different types of generation technologies, storage and demand response, the optimal mix depends on year-round load patterns. The different options have different capabilities and different cost characteristics and should not be blindly lumped together as "capacity" for system planning or even cost allocation and rate design purposes.

Because of these economic considerations, the kind of capacity that one would build to meet short-term coincident peak needs, as well as reserves on short notice throughout the year, is much different than the capacity needed to generate year-round. Indeed, for very infrequent needs, demand response (paying customers to curtail usage for a short period) can be much cheaper than building *any* kind of generation resource that is seldom used. To be economic, capacity built to serve only short-term needs generally has low upfront investment costs, such as combustion turbines or demand response, but can have higher short-term variable costs when it is used. The combustion turbine is cheap to build but relatively inefficient and expensive to run. In contrast, a larger upfront investment can only be justified by lower expected short-run variable generation costs and a higher expected capacity factor. As a result, this high-upfront-cost capacity lowers the total cost of both meeting peak demand and serving energy needs over the planning horizon. This cost reduction means that not all generation capacity costs are caused by system peaks or even reliability needs more broadly. It is also relevant that the choice of some generation technologies is justified partly by ratepayer cost considerations and partly by policy requirements.

Many of these same considerations apply to the transmission and distribution systems, and an analyst should look to the underlying purposes and benefits of investments to understand their role in system planning and to allocate and price them properly. Several different kinds of transmission capacity are intended to deliver energy and are not designed primarily to meet reliability needs. A transmission segment that connects a generating unit to the broader transmission network can be properly thought of as a generation-related cost and charged on the same basis as the underlying generator. In some situations, long transmission lines are needed to connect low-cost generation resources, such as remote hydroelectric facilities or mine-mouth coal plants, to the network. These long lines are built to facilitate access to cheap energy, rather than to meet peak demand, and should be classified on that basis. Similarly, transmission lines built to facilitate exchanges between load zones are not necessarily most highly used at peak times but are used to optimize dispatch and trade energy across many hours of the year. Other parts of the transmission and distribution network do need to be sized to meet peak demand and other reliability contingencies. But there are several different engineering

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[53] Reliability can be thought of as having two dimensions: system security and resource adequacy. The former refers to operational time frames, being assured that the system has sufficient resources to meet demand in real time. The latter refers to investment time frames, being assured that the system will continue to deploy needed capacity to reliably serve load over the longer term. Both kinds of reliability are relevant to this discussion.

[54] The details of how this is achieved vary from ISO to ISO and state to state.

options for transmission and distribution networks, which have implications regarding line losses.[55] For example, one reason for choosing higher voltage transmission is that it carries the same power levels at a lower current, which can decrease line losses substantially. Average annual line losses are typically around 7%, but marginal system losses at the time of peak can be 15-20% in many utility systems.[56]

It is only when one gets close to the end user that the components of the system — the final line transformers, secondary distribution lines and service lines — are sized to meet a very localized demand that can be directly attributed to a small number of customers. We collectively term these categories of costs as site infrastructure. Even at this level, there can be significant load diversity among the customers sharing a line transformer. But there are many residential customers (e.g., single-family homes) with dedicated service lines and a fair number of secondary general service customers that have dedicated line transformers.

Billing and customer service costs are directly related to the number of customers, although larger customers often have more sophisticated bills and other arrangements that add incremental costs in these categories. Traditionally, a simple meter was categorized as a billing cost, and every customer needed a single meter. However, the purposes of advanced metering infrastructure, and its related pricing and data collection capabilities, goes far beyond what is necessary strictly for billing. As a result, advanced metering infrastructure can be fairly allocated and efficiently charged to customers in a manner that reflects these broader purposes.

Expenditures for public policy programs and requirements — such as energy efficiency or energy waste reduction programs, renewable portfolio standards, and discounts for low-income customers, senior citizens or industrial customers — are driven by a wide range of motivations, including reductions in electric system costs, supporting innovation, public health and environmental benefits and broader economic and societal goals. Some of these categories, particularly energy efficiency and energy waste reduction, can be thought of as part of the efficient least-cost operation and planning of the electric system and thus have a cost causation basis driven by usage and customer behavior. Expenditures that are more driven by broader societal goals, such as certain kinds of customer discounts, do not have a cost causation basis in the same way.

Last but not least, administrative and general (A&G) costs generally support all of a utility's functions and scale with the overall size of the enterprise. For example, an office building and parking lot is designed and sized for the number of employees that use that location; customer characteristics do not directly influence costs.

Although all customer behavior influences these cost drivers in different ways, it is important to note how trends in DER adoption, and in some cases the adoption of solar PV distributed generation specifically, are changing the nature of the electric system and basic

[55] See generally Lazar, J., & Baldwin, X. (2011). *Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/valuing-the-contribution-of-energy-efficiency-to-avoided-marginal-line-losses-and-reserve-requirements/

[56] Lazar & Baldwin, 2011, p. 1.

patterns of cost causation. DG customers may influence generation costs by causing a shift in peak time or level. This shift has occurred in states with high penetrations of distributed solar, such as Hawaii.[57] As discussed above in Section 2.D, system planners must dispatch plants to meet the net load curve, subtracting the generation from nondispatchable resources interconnected at either the transmission or distribution level from gross load.

In addition, DG can affect the need for shared distribution infrastructure by reducing certain distribution circuit peaks or, conversely, by increasing infrastructure investment requirements for DG interconnection or substation investments to allow power to flow up from distribution circuits to the higher voltage distribution grid under certain conditions. Higher penetrations of variable renewable resources generally (including utility-scale resources) may lead to the need for additional fast ramping resources and other measures to "teach the duck to fly"[58] — that is, to smooth out the duck curve to match fluctuations in renewable energy production. Extremely high penetrations of certain technologies may require investments in a broader range of dispatchable resources, such as long-duration energy storage. More localized distribution issues could be caused by clustering adoption. While some of these issues are no longer theoretical in some jurisdictions, they should be properly quantified to keep them in perspective. Jurisdictions with low levels of DG penetration, such as Michigan, may not need to act on these issues in the near future, but it rarely hurts to look beyond the horizon for foreseeable issues.

D. Benefit-Cost Analyses

Jurisdictions in the United States that have implemented ratepayer-funded energy efficiency programs typically subject these programs to benefit-cost analyses to determine whether the investments are cost-effective. Regulators in these jurisdictions require that these programs and measures pass one or several cost-effectiveness tests before programs are included in rates.[59] In some states, cost-effectiveness tests are also used to assess programs for other types of DERs, including distributed generation. The type of test selected has huge implications in determining which programs pass, as different cost tests consider costs and benefits from differing perspectives (e.g., the utility system, program participants, or society as a whole). The breadth of the factors considered also varies among the tests and can further vary depending on the willingness of the jurisdiction to pursue a comprehensive assessment of the benefits of energy efficiency or other DERs. RAP long ago developed the concept of representing the benefits of energy efficiency as a layer cake, but this imagery also works for DERs in general. Figure 12 on the next page updates the layer cake to display a list of benefits to consider for DERs.

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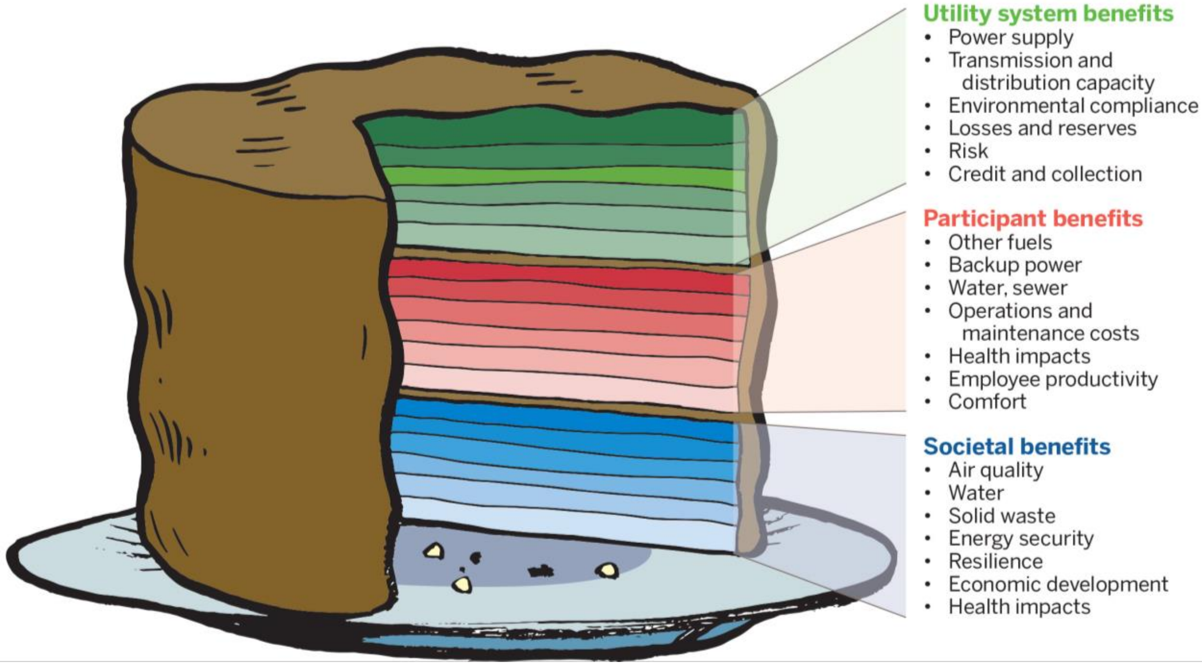
[57] In Hawaii, June load shapes changed as increased levels of distributed solar were added to the system. In 2006, the system peak demand was approximately 1,200 MW at 1 to 3 p.m. By 2017, with extensive deployment of customer-sited solar, the peak demand was 1,068 MW at 9 p.m. Federal Energy Regulatory Commission, n.d.

[58] Lazar, J. (2016). *Teaching the "duck" to fly* (2nd ed.). Regulatory Assistance Project. https://www.raponline.org/knowledge-center/teaching-the-duck-to-fly-second-edition/

[59] Lazar, J., & Colburn, K. (2013). *Recognizing the full value of energy efficiency*. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/recognizing-the-full-value-of-energy-efficiency/

Figure 12. A "layer cake" of benefits from distributed energy resources



It is important to recognize that the different tests provide different types of information from different perspectives. Although all of these different perspectives may be considered relevant and important and warrant consideration, states typically use one primary test to determine whether to invest ratepayer funds in DER programs, even where the state requires other tests as well.[60] The most commonly used tests are the program administrator cost test or utility cost test, the total resource cost test and the societal cost test. The ratepayer impact measure test and participant cost test are less commonly used and almost never used as primary tests.[61] Jurisdictional cost tests, originally described in the *National Standard Practice Manual*,[62] reflect a new approach to cost-effectiveness testing where each jurisdiction is encouraged to develop its own unique test. Figure 13 on the next page depicts how these tests differ.[63]

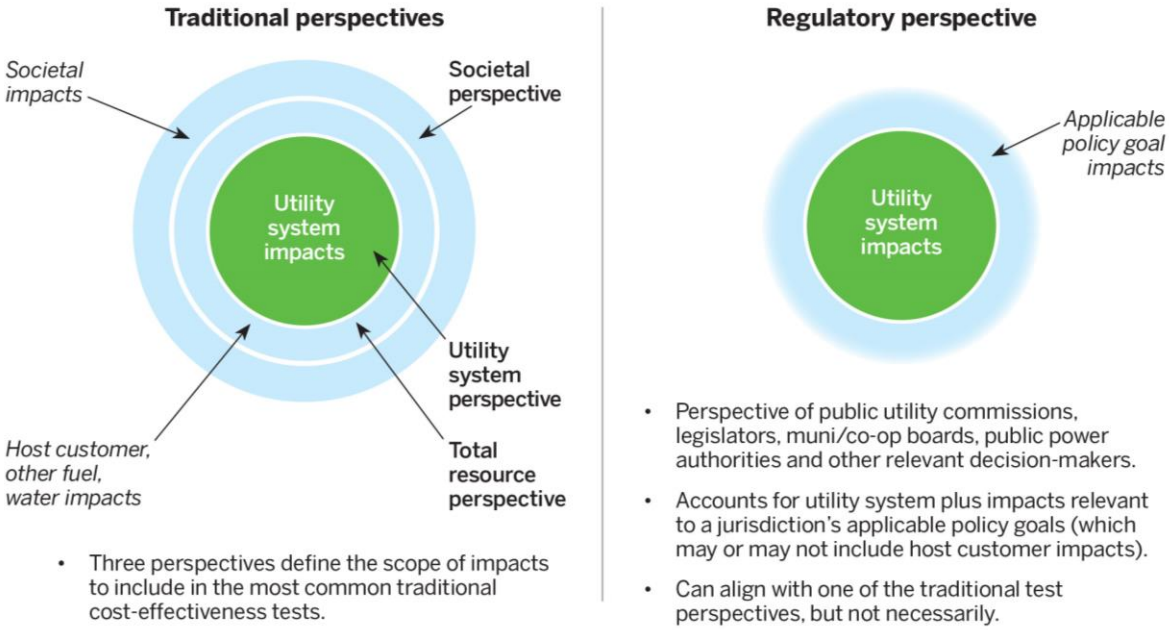
[60] Woolf, T., Malone, E., Kallay, J., & Takahashi, K. (2013). *Energy efficiency cost-effectiveness screening in the Northeast and mid-Atlantic states.* Synapse Energy Economics. https://www.synapse-energy.com/sites/default/files/SynapseReport.2013-10.NEEP_.EMV-Screening.13-041.pdf

[61] Lazar & Colburn, 2013.

[62] National Energy Screening Project. (2020). *National standard practice manual for benefit-cost analysis of distributed energy resources.* https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

[63] National Energy Screening Project, 2020, Figure S-1.

Figure 13. Depiction of differences between cost-effectiveness tests



Source: National Energy Screening Project. (2020). *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*

Program Administrator or Utility Cost Test

The program administrator cost test — also called the utility cost test (UCT) — looks at costs and benefits from the perspective of the utility offering the DER program. Generally, this test seeks to answer the question of whether the utility's revenue requirements will decrease as a result of the program. However, in states that allow retail competition in energy supply, it is more accurate to say that this test measures whether utility system costs — that is, the combination of the utility's delivery costs plus the costs of energy supply (regardless of the supplier) — will decrease. Using the UCT for DER program evaluation almost always makes sense because it reveals whether the benefits to a utility will exceed the cost to the utility (which will ultimately be recovered from its customers). This information is always important for a regulator to have, and only rarely will it make sense to approve a program that fails the UCT. Many jurisdictions have opted not to use the UCT as their primary cost-effectiveness test, however, because it gives an incomplete picture of the costs and benefits of DERs. The picture is incomplete because, in most cases, DER programs do not cover the full cost of a DER investment. Instead, customers put their own money into the investment, supplemented by utility program incentives, and receive their own benefits that are additional to the utility's benefits. The total resource cost (TRC) test, described below, is more commonly used than the UCT as a primary test because it can compare total costs and total benefits for all the parties investing in a DER (i.e., the utility and the customer).

Total Resource Cost Test

The TRC test seeks to answer the question of whether the total combined costs for the utility offering a DER program and the participating customers will decrease. This test includes the full costs of the measure, program administrative costs and the benefits the measure provides not just to the utility but also to the participants, including operations and maintenance (O&M) savings, increased productivity, lowered absenteeism and other non-energy benefits. Although most states specify the TRC test as the primary means for determining cost-effectiveness, very few actually require that all participant benefits be quantified.[64] As a consequence, this test often severely underestimates the benefits of DERs in practice. It is crucial that analysts and regulators take full account of resource related non-energy benefits in applying the TRC test. Where these benefits cannot be easily quantified, the use of placeholders or default values may be necessary; otherwise, the value of these benefits is carried as zero, which is almost certainly the wrong number.[65] If the TRC test is used as the primary cost-effectiveness test, the UCT can still be employed as a secondary test. In cases where a proposed program passes the TRC test but fails the UCT, it may be possible to adjust the utility program incentives to ensure that the program will pass both tests.

Societal Cost Test

The societal cost test includes all costs and benefits experienced by society as a whole. It seeks to answer the question of whether society is better off with the program. It includes all of the TRC test costs and benefits, but it also includes the impacts on people who are not customers of the utility offering the DER program. The societal cost test looks at impacts outside the utility's service territory and considers environmental externalities and other non-energy benefits that the market does not currently value.[66] The test may also include non-energy costs, such as a reduction in nonparticipant property values if a neighbor uses a DER program to erect a small wind turbine.[67] In some cases, emissions costs are included in the market price used to determine avoided costs or are otherwise explicitly included in the TRC calculation. Emissions permit costs may already be included in the market price of electricity in some jurisdictions. Other jurisdictions include a variety of measures for the cost of emissions in the societal cost test.[68]

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[64] Lazar & Colburn, 2013.

[65] Lazar & Colburn, 2013.

[66] Lazar & Colburn, 2013.

[67] This is a hypothetical example included simply to illustrate the possibility of non-energy costs for nonparticipants. In fact, the Lawrence Berkeley National Laboratory collected data on almost 7,500 sales of homes situated within 10 miles of wind facilities. The laboratory's analysis found that "if property value impacts exist, they are too small and/or too infrequent to result in any widespread, statistically observable impact, although the possibility that individual homes or small numbers of homes have been or could be negatively impacted cannot be dismissed." U.S. Department of Energy, Wind Energy Technologies Office. (n.d.). *Wind energy projects and property values*. WINDExchange. https://windexchange.energy.gov/projects/property-values

[68] National Action Plan for Energy Efficiency. (2008). *Understanding cost-effectiveness of energy efficiency programs: Best practices, technical methods, and emerging issues for policy makers.* Energy and Environmental Economics, Inc.; Regulatory Assistance Project. https://19january2017snapshot.epa.gov/sites/production/files/2015-08/documents/understanding_cost-effectiveness_of_energy_efficiency_programs_best_practices_technical_methods_and_emerging_issues_for_policy-makers.pdf

Jurisdiction-Specific Test

The cost tests described above often do not address pertinent jurisdictional or state policies and as a result are sometimes modified in an ad hoc manner that varies across states. Additionally, these modified tests frequently treat different types of DERs inconsistently, which could lead to overinvestment in some DERs and underinvestment in others.[69] Recognizing these deficiencies, the National Energy Screening Project developed the *National Standard Practice Manual* for DERs, which describes a process and principles that each state can use to create its own jurisdiction-specific test. This test is calculated from the perspective of regulators or decision-makers. It seeks to determine whether the program or measure being analyzed will reduce the cost of meeting utility system needs *while achieving the jurisdiction's applicable policy goals*. It includes the utility system impacts, plus those impacts associated with achieving applicable state policy goals.[70] So, for example, if a state has an established goal to deploy rooftop solar, a jurisdiction-specific test can be designed that reveals whether an electric utility DER program will reduce the total cost of serving customers' electric needs *and* achieving the rooftop solar goal. In this hypothetical scenario, a utility incentive program that increases utility costs could pass the if it is the best or only way to achieve the rooftop solar deployment goal. The process for developing a jurisdiction-specific test involves five steps shown in Figure 14 on the next page.[71]

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[69] Michals, J. (2021, February 25). *National standard practice manual for benefit-cost analysis of distributed energy resources (NSPM for DERs): Exploring optimization through benefit-cost analysis* [Presentation]. https://pubs.naruc.org/pub/685F9A10-155D-0A36-31D1-C5B6E6012E03

[70] U.S. Department of Energy. (2021, February 11). *Passing the test: How are residential energy efficiency cost effectiveness tests changing?* [PowerPoint slides]. https://www.energy.gov/sites/default/files/2021/03/f83/bbrn-peer-test-021121.pdf

[71] National Energy Screening Project, 2020.

Figure 14. Steps to develop a jurisdiction-specific test

Step 1 Articulate applicable policy goals
Articulate the jurisdiction's applicable policy goals related to distributed energy resources.

Step 2 Include all utility system impacts
Identify and include the full range of utility system impacts in the primary test, and all benefit-cost analysis tests.

Step 3 Decide which non-utility system impacts to include
Identify those non-utility system impacts to include in the primary test based on applicable policy goals identified in Step 1:

- Determine whether to include host customer impacts, low-income impacts, other fuel and water impacts, and/or societal impacts.

Step 4 Ensure that benefits and costs are properly addressed
Ensure that the impacts identified in Steps 2 and 3 are properly addressed, where:

- Benefits and costs are treated symmetrically.
- Relevant and material impacts are included, even if hard to quantify.
- Benefits and costs are not double-counted.
- Benefits and costs are treated consistently across DER types.

Step 5 Establish comprehensive, transparent documentation
Establish comprehensive, transparent documentation and reporting, whereby:

- The process used to determine the primary test is fully documented.
- Reporting requirements and/or use of templates for presenting assumptions and results are developed.

Note: The 5-step process is not necessarily chronological in order and often requires iteration.

Source: National Energy Screening Project. (2020). *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*

Ratepayer Impact Measure Test

The ratepayer impact measure (RIM) test examines the impact of utility-sponsored DER programs on future customer rates. The difference between the RIM test and the UCT is that the RIM test adds utility lost revenues (i.e., DER program participant bill savings) to the actual costs the utility will incur. A reduction in utility revenues may eventually force the utility to raise rates to recover certain costs. Very few states have ever used the RIM test as the primary determinant of cost-effectiveness for their DER programs, in part because it doesn't really indicate whether a measure is inherently cost-effective. Instead, it indicates whether some of the utility's embedded costs might be shifted from DER program participants to nonparticipants. Although almost no utility regulators use this as a primary test for decision-making, many regulators are appropriately concerned about cost shifting and the potential magnitude of rate impacts and do consider the results of the RIM test.[72]

[72] Lazar & Colburn, 2013.

E. Cost Allocation Frameworks[73]

In cost allocation — a step in the rate-making process — regulators determine how to equitably divide a set amount of costs among several broadly defined classes of ratepayers. In most situations, cost allocation is a zero-sum process where lower costs for any one group of customers lead to higher costs for another group. However, the techniques used in cost allocation have been designed to mediate these disputes between competing sets of interests. In addition, the data and analysis produced for the cost allocation process can also provide meaningful information to assist in rate design, such as the seasons and hours when costs are highest and lowest, categorized by system component as well as by customer class. At the highest level, there are two partly overlapping principles to help guide the task of allocating costs efficiently and equitably:

1. Cost causation: Why were the costs incurred?
2. Costs follow benefits: Who benefits?

Two major quantitative frameworks are used around the United States for cost allocation: (1) embedded cost of service studies and (2) marginal cost of service studies. Embedded cost studies use analytical methods, including historic load research data, to divide up existing costs making up the existing revenue requirement. Marginal cost studies look at changes in cost that will be driven by changes in customer requirements over a reasonable future planning period of perhaps five to 20 years and typically involve more substantial forward-looking analysis than embedded cost techniques.[74]

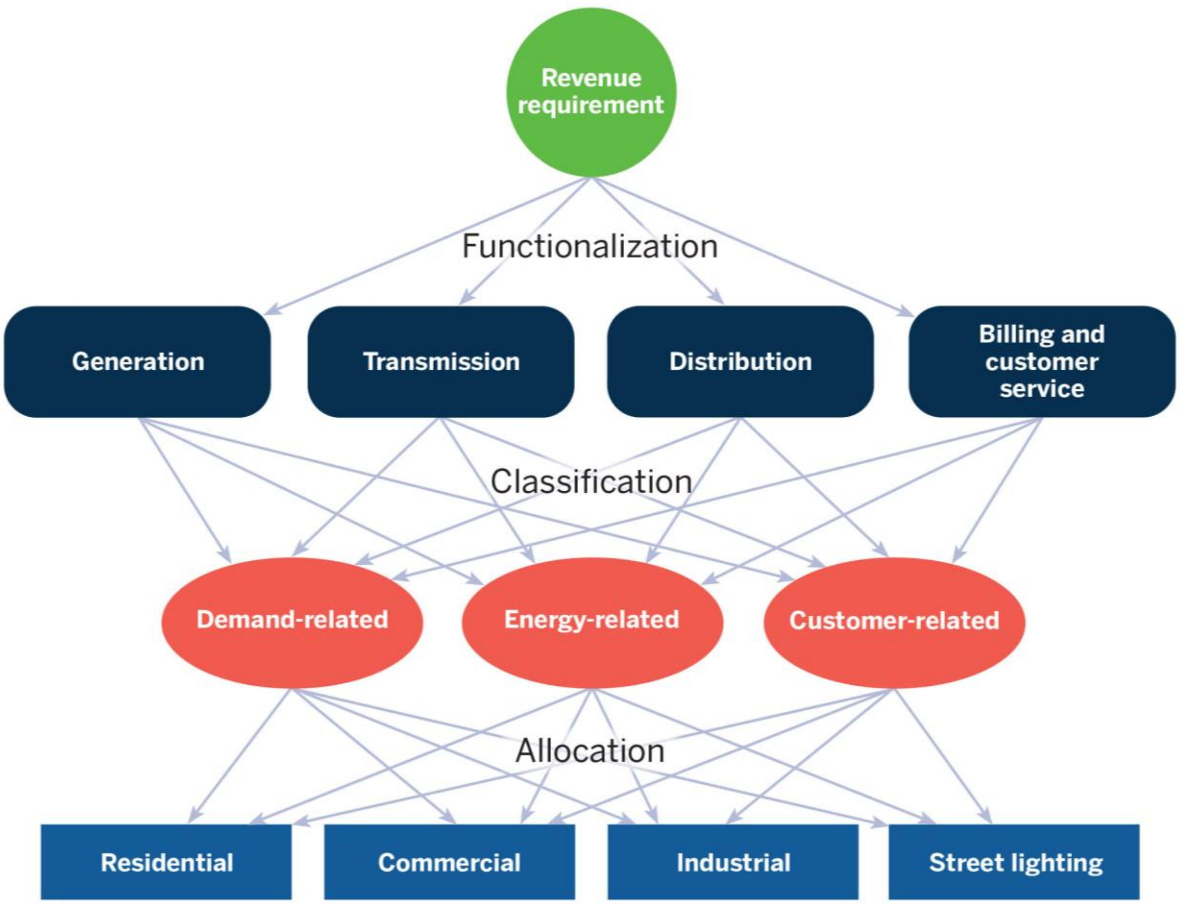
Embedded cost of service studies, sometimes termed fully allocated cost of service studies, are the most commonly used utility cost allocation study. Most state regulators require them, and nearly all self-regulated utilities rely on embedded cost of service studies. The distinctive feature of these studies is that they are focused on the cost of service and usage patterns in a test year, typically either immediately before the filing of the rate case or the future year that begins when new rates are scheduled to take effect. This focus means there is very little that accounts for changes over time, so it is primarily a static snapshot approach. The MPSC uses a projected test year in rate cases, typically one or two years in the future from the filing of a rate case.

[73] This section is derived from much more comprehensive descriptions and analysis in Lazar et al., 2020.

[74] In many embedded cost jurisdictions, additional consideration of marginal costs can be incorporated at the rate design stage.

As shown in Figure 15, embedded cost allocation techniques follow three typical steps: functionalization, classification and allocation. There can also be more than one way across the three steps to achieve a similar result in this framework. But as a general matter in this framework, a cost allocation analyst is forced to choose which of the three classifications (demand-related, energy-related or customer-related) fits best for each category of costs, a process that has been long understood to have major flaws. In most cases, the allocation step contains more nuance and flexibility where many different allocators are used for different kinds of costs.

Figure 15. Traditional embedded cost allocation approach



Seeing the weaknesses of the historical embedded cost allocation techniques, as well as typical rate design structures, regulators in many jurisdictions across the United States in the 1970s and 1980s adopted marginal cost of service techniques instead. In contrast to the static snapshot that is typical of embedded cost approaches, marginal cost of service studies explicitly account for how costs change over time and which rate class characteristics are responsible for driving those changes. The fundamental principle of marginal cost pricing is that economic efficiency is served when prices reflect current or future costs — that is, the true value today of the resources that are being used to serve demand — rather than historical embedded costs. Importantly, marginal costs can be measured in the short run or long run. A true short-run marginal cost study will measure only a fraction of the cost of service, the portion that varies from hour to hour with usage assuming no changes in the capital stock. By contrast, a total service long-run marginal cost study measures the cost of replacing today's power system with an optimally designed and sized system that uses the newest technology. More typically, marginal cost of service studies used a variety of medium- to long-term values for different elements of the electric system, and regulators used these results to inform both cost allocation and pricing. Despite the theoretical appeal of these marginal cost methods, the complexity of these estimates proved daunting over the past several decades and led to numerous stakeholder disputes. Many jurisdictions have migrated back to the relative simplicity of embedded cost allocation techniques.

However, one key insight of marginal cost allocation techniques is the idea that marginal cost pricing will almost never approximate the revenue requirement determined in a rate case using the embedded cost of service. As a result, it escapes the trap described by James C. Bonbright (see the quote at right) because a round peg is never forced into a square hole. In some historical circumstances (e.g., high marginal fuel prices in the 1970s), marginal cost pricing may have collected more than the revenue requirement, but in most prevailing conditions, it is thought that marginal cost pricing for electric utilities will collect less than the embedded cost of service.[76] The additional costs that need to be collected to meet the full revenue requirement are called residual costs. There is no generally accepted way to allocate and price these costs, although jurisdictions have used both the "equal percentage of marginal cost" technique or the inverse-elasticity technique to allocate these costs.

> "But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in my opinion is that it belongs to none of them…. But the fully distributed cost analyst dare not avail himself of this solution, since he is the prisoner of his own assumption that 'the sum of the parts equals the whole.' He is therefore under impelling pressure to 'fudge' his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other categories."
>
> James C. Bonbright, *Principles of Public Utility Rates*[75]

[75] Bonbright, 1961, pp. 348-349.

[76] This circumstance often excludes externalities from the definition of marginal cost.

What is a cost shift?

In any utility pricing scheme based on averages across times and locations, cost shifts are inevitable. Furthermore, different stakeholders may define and use the term differently. Clarifying the potential issue could help in solving it, although the different definitions are partially overlapping.

The first set of possibilities can be referred to as embedded cost definitions of cost shifts.

> **Embedded cost shifts among customer classes at the cost allocation stage.** In between rate cases, a customer class that reduces its cost allocation determinants disproportionately compared to the other classes will reduce its revenue allocation in the next rate case, leading to higher revenue allocations to other customer classes.

> **Embedded cost shifts within a customer class at the rate design stage.** In a rate case, if a given set of customers has reduced its billing determinants significantly, then a given *rate* must be higher to collect the same amount of revenue from that class.

Mechanically, these embedded cost definitions of a cost shift are straightforward, but not everyone will agree whether these shifts represent a problem that needs to be solved. Possible disagreements are the reasonableness of current cost allocation and rate design techniques, as well as the lag between current day rates and the time frame where long-run cost savings can be achieved. However, some parties may instead point to the ratepayer and societal benefits that are not explicitly considered in either cost allocation or rate design. Many of these benefits are typically considered more explicitly in cost-benefit tests. This leads to a different marginal cost definition of a cost shift.

> **A marginal cost definition** of a cost shift asks whether the value of the resource falls short of its compensation or vice versa. For example, if a solar PV customer is effectively compensated at a retail rate of 12 cents per kWh but provides a value of 14 cents per kWh, then there is no cost shift under this marginal cost definition. However, if that solar PV customer provides a value of only 10 cents per kWh, then that would represent a cost shift under this definition.

Again, this definition is conceptually straightforward but subject to numerous potential disputes. Parties may disagree about many different aspects of value, such as how to calculate long-run electric system values and whether to include societal benefits. Picking the relevant benefits to include in this analysis, as well as consideration of any relevant costs, is strongly overlapping with the choice of a benefit-cost analysis framework. Some stakeholders may also disagree with this framework, arguing instead that the way to maximize ratepayer benefits is to procure at least cost.

The last potential definition of a cost shift revolves around the issue of residual costs. This issue can be considered under either the embedded cost framework or the marginal cost framework, although marginal costs techniques wrestle with it more explicitly.

> **A residual cost definition** of a cost shift asks whether a group of customers contributes the same additional revenue above their marginal costs toward the utility's embedded cost of service, such that other customers are not asked to contribute more than they had previously.

Under the embedded cost framework, this question is similar to those that can be asked about the cost causation basis of embedded cost allocation and pricing techniques. This question is different than the above marginal cost definition of cost shifting because residual costs are *in addition to* marginal electric system costs that utilities had expected to collect from the relevant group of customers. However, calculated residual costs are likely to be much lower if societal benefits are included in the marginal cost calculation. Different rate design constructs, including the inflow/outflow framework and the potential pathways laid out in Section 6, provide different ways to manage cost shifts as a part of a balanced overall rate-making decision.

4. Overarching Program Parameters

Rate design for distributed energy resources occurs within the context of a utility tariff that specifies the terms and conditions of exchange between the resource owner and the utility. These tariffs often operate in the context of utility commission regulations and orders, as well as other statutory and regulatory frameworks, which can be described as a broader program for distributed energy resources. The tariff specifies how customers will be billed by the utility or in some cases compensated financially outside their traditional utility bill. The tariff also specifies the obligations of the DER owner and the utility relative to the operation and use of the resource. Metering and billing are foundational to the terms and conditions of the transaction, and the regulator has options in defining how metering and billing will work. The first part of this section describes those options.

The second part of this section describes other terms and conditions that are typically included in a tariff for distributed generation or DERs more generally. Other terms and conditions often include customer eligibility requirements, interconnection requirements, renewable energy credit (REC) ownership requirements, data sharing and transparency requirements, and specification of any program or nonbypassable charge obligations accepted by the DG resource owner. Tariffs are not static, and over time the terms and conditions available to customers often change. The third part of this section describes how regulators address the transition of tariffs over time. This section concludes with a discussion of how underlying analyses are completed and reviewed by regulators and introduces the role of pilots in testing new tariff possibilities.

A. Metering and Billing Frameworks

The fundamental exchange between utility customers, including those with DERs, and the utility is captured in the specification of how their bills are calculated and designed. For customers with distributed energy resources, there are numerous options to consider which are described at a high level in this section.

Monthly Netting

The most typical metering setup for DG customers across the country to date has been net energy metering (NEM) with monthly netting. This setup measures net kWh consumption[77] each month to determine the customer's bill. Consumption offsets production from the DG resource over the course of the month, and if there is a net consumption of energy for that month, the customer is assessed a charge for that net consumption based on the tariff rate design. If there is a net production for the month, then the customer is paid or credited based on the export credit structure specified in the tariff. While a common policy has been to define the export credit at the full retail rate for the customer class, there are now many different variations on this approach across the country. For months with net production, the resulting credits are typically applied toward

[77] Under the simplest version of this metering setup, a utility cannot tell any more details about how a customer is using the system. The kWh meter counts up as energy flows in and reverses direction as energy flows out. In some jurisdictions, however, monthly netting is calculated from more sophisticated metering data.

future billing periods rather than resulting in a payment to the customer. Under monthly netting, all hours of the month are fungible in the sense that net consumption in any hour is counted the same as net consumption in any other hour. In this framework, customers minimize their bill (or maximize their credit value) by lowering their consumption and increasing their generation (to the extent that generation can be managed or influenced).

Inflow/Outflow Measurement or Instantaneous Netting

The metering setup, known either as inflow/outflow (as it is called in Michigan) or as instantaneous netting, typically measures a customer's net consumption or net production in real time. At the end of the billing period, there is a separate billing determinant for kWh of inflow (imports, or energy received from the grid) and outflow (exports, or energy delivered to the grid). Several different metering setups are capable of billing on this basis. The simplest has two kWh registers, one that tracks kWh imported and another that tracks kWh exported. Advanced meters and interval metering arrangements may either track imports and exports separately for each time period or else calculate net imports or net exports within a small (e.g., five-minute) interval, which tends to produce a very similar result.[78] Under this framework, the customer is still billed every month but always has two non-zero kWh billing determinants if there are any exports to the grid. If the credit for exports is lower than the retail rate for imports, then the customer can minimize their bills by shifting consumption to times that they would otherwise be exporting energy because self-consumption is compensated at a higher rate than exports.

Time-of-Use Netting

In TOU netting, net imports and net exports are aggregated for all hours within like time periods. For example, if there is an on-peak range of hours specified in the tariff (e.g., 2 p.m. to 7 p.m. on weekdays), then all on-peak hours are aggregated for the billing period to produce one billing determinant for those hours. In TOU netting, hourly net imports or exports are fungible only for hours within the same TOU period. Some jurisdictions and utilities have applied TOU netting in a rigid way, where kWh credits earned during one pricing period (e.g., summer on-peak) can only be used during that same window in subsequent billing periods. Monetary crediting, discussed further in Section 5.B, solves this issue, but there can be other ways to address it.

Buy-All/Credit-All Metering and Billing

Monthly netting, inflow/outflow billing, and TOU netting contemplate compensation of a DG resource that exists behind the meter at a site where use of power from the grid, self-consumption of on-site generation, and exports to the grid are all structurally permissible. In the alternative, buy-all/credit-all metering can apply to behind-the-meter installations as well, but it is worth noting that it can also be appropriate for standalone DG resources that sit in front of the meter. In a buy-all/credit-all construct, customers buy all of the energy that they consume from the utility at the retail tariff and are compensated for all

[78] This result would only be noticeably different if a customer switched from importing to exporting within the time intervals and managed to have significant netting of imports and exports within those interval windows.

energy they produce at an export tariff price. Buy-all/credit-all arrangements require metering that tracks production separately from consumption to preclude any self-consumption of DG production by the customer. This metering is often an incremental cost, although sometimes this utility billing framework can take advantage of a generation production meter required for another program or purpose.

One issue with this framework is that generation, storage and consumption cannot all be optimized together. Depending on how the wiring and interconnection is required to be done, a customer could not use a single storage installation to manage both generation and usage, as doing so would defeat the purpose of separate billing of gross generation and gross consumption. Both the retail consumption rate and the export credit structure can be managed independently, however, and could be as simple or as sophisticated as desired in either case, as long as the relevant metering and billing systems can handle it.

Stand-Alone DERs and Remote or Virtual Net Metering

Like buy-all/credit-all metering, where on-site projects are metered separately, some jurisdictions allow distributed energy resources to interconnect to the distribution system regardless of any particular arrangement with or proximity to specific electricity customers. These resources are then allowed to earn export credits, just like other DER exports, and allocate those credits to electric customers according to the rules of the particular jurisdiction. This type of arrangement goes by many different labels, such as remote or virtual net metering, but can more generically be referred to as stand-alone distributed energy resources. This model is the predominant one for community solar programs in many states. Since there is no presumption that these projects are located near any other customers, each stand-alone distributed energy resource requires its own metering. Many different compensation structures are possible depending on the metering for these projects.

Options That Require Advanced Metering and Advanced Inverters

With advanced metering infrastructure, the options for netting methods expand enormously. Netting periods could be based on the smallest interval that the metering and billing system can handle or any aggregation of those time periods. That can include hourly netting or inflow/outflow measurement within each hourly period. These more complex structures would likely only be appropriate for more sophisticated customers, however, or would need to wait for the availability of reasonably affordable automated energy management technology.

In addition, DER resources with advanced inverter functionality can offer additional services like voltage and frequency regulation. DERs may also become part of a nonwires solution that addresses local grid congestion or mitigates local grid stress. In that case, the DER is providing a specific service under specified terms and is separately compensated for those capabilities. Compensation for the functionalities delivered by advanced capabilities can be specified as options within a tariff, or they may exist in a separate tariff that is targeted at acquiring these additional services. Although these granular options for compensating DG resources for services other than energy alone are rare today, they are technically feasible but will only become common when utility distribution information systems evolve to integrate best practice digital technologies that exist today, which will likely become more prevalent in the coming decade.

B. Other Program and Tariff Design Features

Billing and metering specifications are the central feature of a distributed energy resource tariff, but tariffs include other provisions that clarify eligibility and obligations of participating customers and the utility. This section describes some of these features.

Tariff Eligibility by Customer Class and Resource Specification

Customers who own and operate DER are not homogenous. All customers must interconnect their resource to the utility distribution system in compliance with adopted interconnection requirements, but the interconnection requirements can vary. Customers differ based on their energy requirements, on the size of their resource, on the combination of resources they operate and on how the resource is interconnected to the grid. For example, larger systems are likely to require more significant interconnection study and may well include certain dedicated facilities that a smaller installation would not require. Similarly, customers that adopt solar and storage facilities may need different interconnection requirements and offer a different range of grid services. And, of course, larger C&I customers adopt resources in a far different context than your average residential customer. For a given set of customers, there may be restrictions on the size or other features of the distributed energy resource that they are allowed to adopt or the manner in which they operate their resources. These restrictions may exist for reasons unrelated to the electric system impacts, such as U.S. Internal Revenue Service restrictions on the applicability of tax credits. For all of these reasons, more than one tariff may be required, and a given tariff would take into consideration and align with the situational context of the customer.

Beyond the requirements that apply to a specific customer, many states, including Michigan, have put limits on the overall participation in the program. These limits, sometimes referred to as net metering caps, may be arbitrary from an electric system perspective but can serve as a check-in for evaluation of the relevant policies. In Michigan, this limitation applies to all customers under the legacy net metering and DG programs. In other states, the relevant cap may apply to only a subset of projects. In New York, it was decided that the cap no longer applied once significant reforms were made to the relevant compensation structures. In Massachusetts, the caps only apply to larger projects, exempting projects less than 10 kW on a single-phase circuit and projects less than 25 kW on a three-phase circuit.[79]

[79] Massachusetts General Laws, Chapter 164, Section 139(i). https://malegislature.gov/Laws/GeneralLaws/PartI/TitleXXII/Chapter164/Section139

Tariff Requirements Addressing Information Transparency and Control of the Resource

DER owners and operators benefit from transparent information on grid conditions and grid resource needs so that the operation of the facilities can be optimized. Utilities benefit from transparent information on the use of customer facilities so that the utility can plan for an optimized system that accommodates all resources and loads within the necessary system parameters. Each DER has value on multiple domains — behind the meter, on the distribution system domain and on the wholesale system domain — and realizing value across multiple domains requires transparent information sharing. Sometimes, utilities or a third-party service provider may require control of a DER in exchange for compensating the owner or operator for certain capabilities.

Information sharing, transparency and DG resource control are complex and potentially controversial on both sides of this relationship so the information architecture specified in the tariff can be a difficult negotiation. That being said, there is public benefit to finding the right balance, and the tariff should specify that balance point for the tariff in question. Different tariffs may require different information and control requirements, but every tariff benefits from being clear about the information, privacy and control terms.

Renewable Energy Credit Ownership

In some states, production from renewable generation resources is recognized as generating RECs in proportion to the renewable production from the facility. In some tariffs, the REC is retained by the resource owner, while in others it automatically transfers to the utility administering the tariffs. RECs have value, so specifying the ownership terms and conditions in the tariff is essential. Under a variety of different certification schemes, it is generally thought that ownership of a REC represents a claim to the environmental attributes of that generation. As a result, specific compensation for the environmental values of a resource can be reasonably tied to transfer of REC ownership.

Nonbypassable Charges and Program Costs

Certain costs incurred by the utility on behalf of DER customers or on behalf of all customers may be deemed to be partially or wholly the responsibility of DG resource owners. For example, program administration costs associated with operating a DER program that aligns with a given tariff may be assigned to DER customers operating under that tariff. Other costs, like energy efficiency program costs, may be deemed to be the responsibility of all customers, and the tariff may need to specify the obligations of the DER customer to continue to contribute to these costs after they migrate to a new tariff. This latter category of costs is called nonbypassable charges. Other typical costs included in these charges might be associated with decommissioning nuclear facilities, the securitized cost of retired plants or operating other public purpose programs, such as programs that explicitly support low- and moderate-income customers or utility EV charging programs. Tariffs specify how program costs and nonbypassable charges will be collected for tariff participating customers.

C. Treatment of Preexisting Net Metering and DG Program Customers

When a DER tariff changes, the regulator needs to decide how customers served under the preexisting tariff will be treated. In most states the preexisting customers keep their tariff for some period of time, and new customers are enrolled in the new tariff. The treatment of preexisting customers is sometimes specified in the enabling legislation that caused the original tariff, and sometimes the regulator specified an implicit or explicit expectation of the duration of the tariff. By statute, Michigan has specified that 10 years is an appropriate time frame before preexisting customers must switch to a new tariff, but other jurisdictions have adopted time frames as long as 20 years.[80] The economic justification for allowing preexisting customers to remain on their tariff is often founded in the changing fundamentals of DER ownership over the last decade. Preexisting customers entered into a tariff that was created based on those fundamentals with certain economic expectations. The fundamentals have changed, however. The cost of solar has declined significantly so new customers face a lower cost of ownership and the value of solar to the system may have changed over time as the penetration of solar expanded (e.g., the value of afternoon energy may have declined as the amount of solar increased). In addition, the emergence of less expensive storage has changed the options open to customers who adopt certain DERs today.

If new and existing DG customers are treated differently based on differences in fundamentals and specifications in law, then the creation of a new rate structure with significantly different economics may be more feasible. When existing customers are not allowed to stay on their tariff, severe customer and political backlash has resulted from major reforms. For example, the Nevada Legislature passed AB 405 in 2017, reversing a Nevada Public Utilities Commission decision to take away preexisting tariffs as a part of net metering reform. In some places existing customers do have portions of their tariff changed, however, when new tariffs are introduced. See the California NEM discussion in Appendix B for a brief discussion of that transition. In other words, gradualism in transitions may be a reasonable substitute for extending tariffs for pre-existing DER customers.

D. Process, Analysis and Pilots

The traditional process for utility rate-making has an established structure, where a public utility commission sets the rules and parameters in advance (e.g., the uniform system of accounts), and then the utility presents its affirmative case in a proposal to the commission, along with the required testimony and analysis. Other parties, including commission staff under the MPSC structure, scrutinize the utility's testimony and analysis through discovery and file their own testimony and analysis. The analysis from those other

[80] Nevada and Arizona established 20-year periods for preexisting customers to keep their tariffs. The Nevada Legislature passed AB 405 in 2017, which established 20-year extensions for existing customers of each of the four tariffs specified. For a description of these four tariffs, see Nevada Public Utilities Commission. (n.d.). *Net metering in Nevada*. https://puc.nv.gov/Renewable_Energy/Net_Metering/. The Arizona Corporation Commission opted for a 20-year period in its 2017 decision as reflected in Arizona Public Service tariffs. For a description of the tariff terms, see Arizona Public Service. (n.d.) *Understanding solar*. https://www.aps.com/en/Residential/Service-Plans/Understanding-Solar

parties may either follow the same general parameters as the analysis presented by the utility, or else parties may choose to file analysis that they believe is more relevant and persuasive on the issues in question. Further discovery, cross-examination at a hearing and formal briefs from all parties round out the litigation before the commission decides on the relevant issues.

Although this process works reasonably well on some issues, alternative procedural approaches can level the playing field and give more opportunities to parties that do not have funding to participate from either ratepayers or the state. Convening collaborative working groups, providing intervenor funding and hiring independent experts to do the relevant analysis with stakeholder input are all methods used in many jurisdictions to help make well-informed public policy decisions. The MPSC, or potentially other state agencies, could form a partnership to analyze key questions with the national laboratories under the U.S. Department of Energy or one of Michigan's universities. Different processes could even be used for different parts of a DER rate design proceeding.

In addition, pilots for new rate designs and programs can be used to collect data and create a shared understanding of the potential results and implications of certain reforms. Piloting also has the advantage of offering the opportunity to experiment with more than one tariff design. For example, a more moderate reform can be implemented as a default structure while more complex rates can be tested in pilots.

5. Designing Rates and Credits

When designing retail rates for electric customers, as well as credit structures for customers with export capabilities, the options are nearly limitless.[81] Much like the colors of the rainbow, they can be grouped for convenience, but when examined closely, there are infinite shades of each color, and one color gradually transforms into the next. For example, a demand charge with an annual ratchet shares many properties with typical monthly demand charges, and peak-time rebates share many properties with critical peak pricing — just as purple blends into blue and orange into red.

A. Designing Retail Rates

Fixed Charges

Fixed charges do not change from month to month based on the amount or timing of usage and are generally based on some permanent (or infrequently changed) characteristic of the customer. Customers generally have no way to reduce the fixed portions of their bills other than canceling the service altogether. There are several types of fixed charges.

Monthly Customer Charges

Customer charges apply to each customer in a tariff class, regardless of usage. Under a typical flat monthly customer charge, higher customer charges impose larger burdens on the customers with lower usage within that customer class. For residential customer classes in many jurisdictions, this often means higher bills for low-income households and apartment residents, which all tend to have lower-than-average usage. Ideally, the customer charge should not exceed the customer-specific costs that are attributable to an incremental customer being added to the system (i.e., a service line, billing, collection, simple metering and a share of customer service).

It is most common to have a monthly customer charge that is the same for all customers in a class, but there are variations worth noting. In Nevada, for instance, residential customers are effectively split into two classes: (1) single-family with a customer charge of $12.50 per month and (2) multifamily with a customer charge of $7.70 per month.[82] In several jurisdictions, there are a variety of tiered customer charges and subscription-style customer charges. In Burbank, California, for example, the municipal electric utility has a base residential customer charge of around $9 with a three-tiered system of service size charges depending on the type of customer: an additional $1.40 per month for multifamily customers, an additional $2.80 per month for a single-family-building customer with a panel size less than or equal to 200 amps, or an additional $8.40 per month for a customer with a panel size over 200 amps.[83] Électricité de France has residential tariffs

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[81] A publication on residential rate design generally is Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future.* Regulatory Assistance Project. http://www.raponline.org/document/download/id/7680

[82] NV Energy. (2021). *Nevada Power Company d/b/a NV Energy electric rate schedules for residential customers* [Schedule/pamphlet]. https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/np_res_rate.pdf

[83] City of Burbank Water and Power. (2021, July 1). *How BWP bills for electric use.* https://www.burbankwaterandpower.com/electric/rates-and-charges

with customer charges based on a kVA subscription level that starts at approximately nine euros per month for 3 kVA and escalates to nearly 40 euros per month for a 36 kVA subscription.[84] In the case of Burbank, these customer charge levels will typically not change over time, unless a customer installs a different service panel. But in the case of Électricité de France, customers can choose different subscription levels, making this charge more akin to a subscription or contract demand charge.

System Access Charges

System access charges, sometimes called grid access charges, are essentially fees charged to DG customers each month for the privilege of being connected to the grid.[85] These are often defined as a fixed fee per kW of installed capacity, meaning that the charge a customer sees on each monthly bill varies depending on the size of the DG unit. The New York PSC decided to apply a monthly "customer benefit contribution" charge of approximately $1 per kW DC of installed PV generation to new residential installations beginning in 2022. Part of the rationale for such a charge was that New York has still operated under traditional retail rate net metering for residential customers, and that rate design reforms were waiting for full rollout of advanced metering infrastructure. Revenue from this new charge will to be directed toward New York's low-income discounts as well as energy efficiency and clean energy programs.

Minimum Bills

Minimum bills impose a minimum charge to each customer whose bill as otherwise calculated is below a set threshold. Customers with on-site generation, storage, efficiency and other DERs could be affected by the minimum bill if their metered usage (because of netting or other reasons) is very low, potentially decreasing the value proposition for DERs. Other features of a rate structure for DER customers can have similar impacts to a minimum bill. As noted previously, a rollover policy that prohibits credits from being applied to certain portions of the bill can be thought of like a minimum bill as well.

Energy (per-kWh) Charges

Flat kWh Rate

The simplest form of energy charge is the flat kWh rate, a purely volumetric price derived by dividing the relevant portion of the revenue requirement for a given class of customers by the kWh sales. Since the customer price doesn't vary based on time, homeowners and businesses have no real incentive to minimize their use of electricity during peak demand hours. In many jurisdictions, flat rates have, historically, had either inclining block (where the rate goes up over a certain kWh threshold) or declining block (where the rate goes down over a certain kWh threshold) features.

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[84] Électricité de France. (2021, August). Grille de prix de l'offre de fourniture d'électricité (Tarif Bleu). https://particulier.edf.fr/content/dam/2-Actifs/Documents/Offres/Grille_prix_Tarif_Bleu.pdf

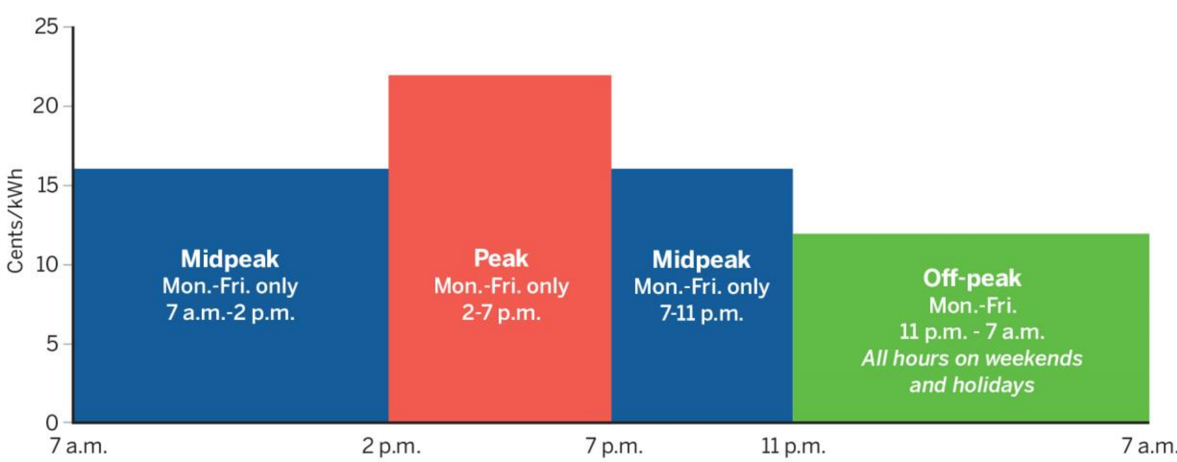
[85] In Michigan, at least one utility has labeled a traditional monthly customer charge as a system access charge.

Time-of-Use Rates

TOU or time-of-day rates vary according to a regular predetermined schedule. These rates recognize that the utilities' cost to generate and deliver the electricity can vary at different times of the day and year. For example, it is more expensive to generate electricity on a hot summer afternoon when everyone is running their air conditioners. Utilities must run less efficient, more expensive power plants to meet this increased demand, which also sets a major portion of capacity costs for generation resource adequacy. By contrast, mild spring or fall weekends when demand for heating and cooling is low may have a surplus of capacity. Well-designed TOU rates are a cost causation improvement over flat or block rates because they offer some correlation between the temporally changing costs of providing energy and the customer's actual consumption of energy. Of course, as the characteristics of the electric system and customers change over time, the structure of TOU rates will continually need to be updated to match cost causation patterns.

TOU rates have been in use for some time in the United States. These rates typically define a multihour time of the day as an on-peak period, during which prices are higher than during off-peak hours. In most cases, on-peak periods are limited to weekdays. The simplest TOU rates have two pricing periods within each billing period. Three pricing periods are fairly common (see Figure 16), and four or more are possible. Simple TOU rates can be implemented with relatively cheap meters (e.g., two registers and a programmable timer), but more advanced TOU rates may require interval meters or full advanced metering infrastructure.

Figure 16. Illustrative three-period summer residential time-of-use rate



Many different choices go into the design of a TOU rate.[86] Moving from two to three pricing periods provides extra flexibility at the cost of some additional complexity for both customers and the utility. In addition, having an on-peak period that is too narrow risks missing or shifting the actual peak without reducing it. Conversely, a broad on-peak period

[86] See generally Colgan, J. T., Delattre, A., Fanshaw, B., Gilliam, R., Hawiger, M., Howat, J., Jester, D., LeBel, M., & Zuckerman, E. (2017, July 15). *Guidance for utilities commissions on time of use rates: A shared perspective from consumer and clean energy advocates.* Electricity rate design review paper No. 2. https://uspirg.org/reports/usp/guidance-utilities-commissions-time-use-rates

makes shifting load outside that window more difficult and may penalize those without options to shift load. Additional options like "feathering," where customers are allowed to choose between different three-hour peak periods (e.g., 2 p.m.-5 p.m., 3 p.m.-6 p.m. or 4 p.m.-7 p.m.), are also possible.

Critical Peak Pricing, Variable Peak Pricing, Peak-Time Rebates and Real-Time Pricing

Critical peak pricing, variable peak pricing and peak-time rebates can be considered refinements to the TOU concept but are determined based on day-to-day electric system needs. Under critical peak pricing, prices during a limited number of specific critical peak periods are set much higher. The customer is given some advance notice of critical peak days, usually a day in advance. This pricing model is designed to produce a response — to get customers to reduce loads during critical peak periods. Variable peak pricing, as it is currently being implemented for Oklahoma Gas & Electric, allows the utility to choose among four daily peak prices depending on wholesale market conditions: low, standard, high and critical.[87] This provides an additional element of discretion beyond just the critical peak designation. Under the peak-time rebate concept, rather than charging customers a high critical peak price, customers are given a credit on their bills if they can reduce usage during a peak-time event. Most versions of critical peak pricing, variable peak pricing and peak-time rebates require advanced metering infrastructure.

Real-time pricing goes further than the previous three options by charging the customer prices that vary by the hour or even smaller time increments. These can be the actual prices set in wholesale markets, or the wholesale price could be adjusted. As more technologies become available that enable customers to respond to electricity prices more dynamically, various forms of real-time pricing may become more widely available. With technologies like smart appliances and energy storage, customers can automatically monitor and respond to prices as they change and monetize the potential benefits through bill savings. Furthermore, ensuring that these customer price signals are directly linked to electric system market conditions can significantly increase the value of a customer's response. This linkage can represent additional risk to a consumer, however, and almost certainly lowers overall bill stability. Figure 17 on the next page depicts this risk-reward trade-off for customers.[88]

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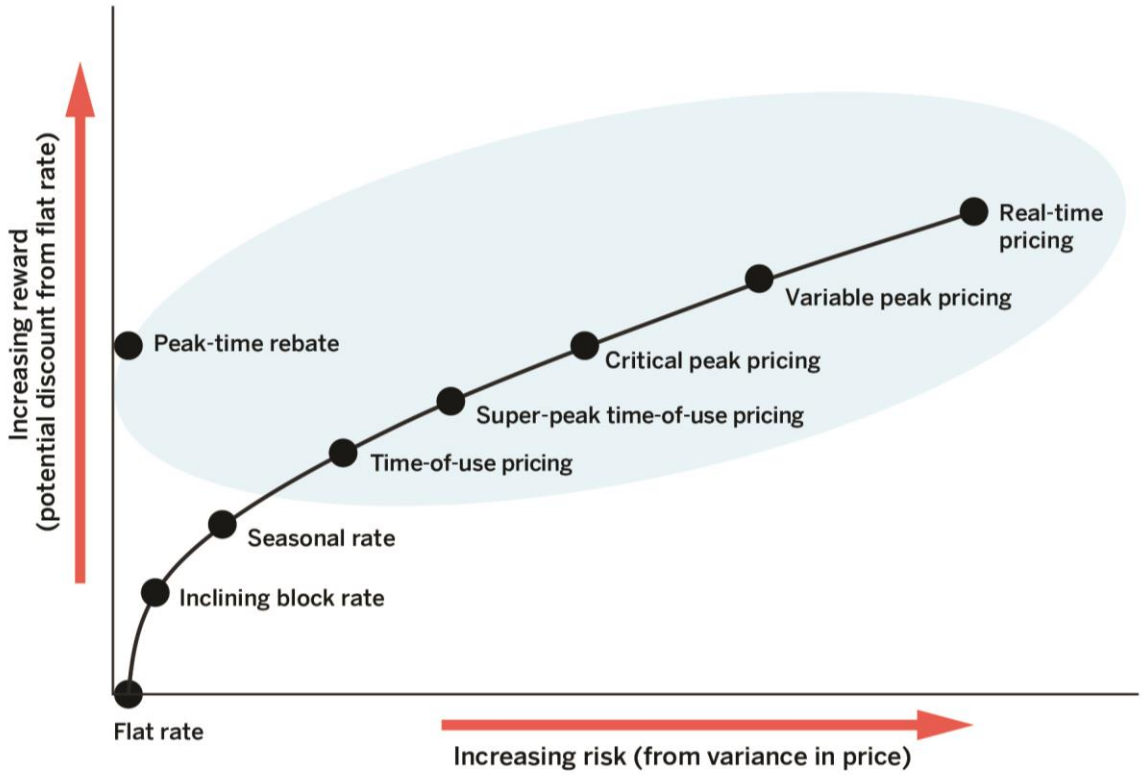
[87] Oklahoma Gas and Electric Company. (2018, June 19). *Standard pricing schedule: R-VPP, state of Oklahoma, residential variable peak pricing, code no. 13V*. https://www.oge.com/wps/wcm/connect/c41a1720-bb78-4316-b829-a348a29fd1b5/3.50+-+R-VPP+Stamped+Approved.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-c41a1720-bb78-4316-b829-a348a29fd1b5-mhatJaA

[88] Faruqui, A., Hledik, R., & Palmer, J. (2012). *Time-varying and dynamic rate design*. Regulatory Assistance Project; The Brattle Group. https://www.raponline.org/ knowledge-center/time-varying-and-dynamic-rate-design

Figure 17. Representation of customer risk-reward trade-off in time-varying tariffs



Source: Faruqui, A., Hledik, R., & Palmer, J. (2012). *Time-Varying and Dynamic Rate Design*

Although this risk to the customers adopting the rate needs to be accounted for, there are also broader ratepayer benefits from least-cost system planning and operation if customers are able to respond appropriately to more sophisticated price signals.

Bidirectional kWh Rates or Distribution Flow Charge

A bidirectional kWh rate to ensure that DER customers pay for usage of the grid has been discussed less frequently than other options.[89] Customers with distributed energy resources are able to self-supply some of their energy needs but also typically export energy to the grid. With some exceptions, kWh rates historically have only applied to imported energy, but they can also be applied as a charge on exports. The concept is that the DER customer taking power from the grid needs the grid in order to have reliable service. This same customer, however, also needs the grid when exporting energy and thus pays a charge when feeding power to the grid. Under the simpler versions of this concept, this charge would show up as a reduced credit for exports[90] and shares many similarities with asymmetric import rate and export credit schemes.

[89] For a longer discussion, see Linvill, C., Shenot, J. & Lazar, J. (2013). *Designing distributed generation tariffs well: Fair compensation for a time of transition.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/designing-distributed-generation-tariffs-well/

[90] It is technically possible that a credit value and an export charge could combine to be a net charge to the DER customer for exporting energy.

One specific version of this concept would set up a separate distribution flow charge that is the same whether a customer is taking a kWh from the grid or exporting a kWh to the grid. The use of a distribution flow charge is consistent with a broader conception of how DER customers will be using the grid in the future and offers a reasonably intuitive metric of the "size" of a customer. Other key features of this concept are that it does not result in any significant rate structure change for customers who do not export energy, that it avoids undue discrimination because the rate is the same across all customers within the class and that it applies both to imports and exports. Such a distribution flow charge could be limited to certain categories of costs that are unambiguously relied upon by the DER customer when exporting, as well as any nonbypassable charges and a portion of A&G costs. Importantly, the rate necessary to recover the relevant categories of costs would be lower than a rate applied just to imports because this new billing determinant (imports plus exports) would be higher, and the costs would be spread over a larger denominator. As a result, customers without DER would actually experience a reduced charge per unit for these costs and thus lower bills.

Demand-Based Charges: Individual Maximum kW Charges and Other Forms of kW Charges

A customer's instantaneous demand for power, denoted in kW, is a measure of the capacity needed to serve the customer's combined end uses in that moment. Most demand charges are based on a customer's maximum call for power in a specified period, typically a month (i.e., a billing period). These rate designs have been around since the beginning of the electric system in the late 1800s. As a practical matter, the charges are not based on the customer's highest instantaneous demand in a period but rather on their highest short-term usage (typically 15, 30 or 60 minutes) in that time.[92] Demand charges come in a variety of forms, ostensibly to address particular needs, but there have long been questions about whether they are an efficient form of pricing.[93]

"The noncoincident demand [charge] method does have some virtue: it encourages customers to level out their consumption over time, in order to minimize their peak taking, hence their share of capacity costs. This, in turn, tends to improve the system's load factor [or] the degree of capacity utilization. But it is basically illogical. It is each user's proportion of consumption at the system's peak that measures the share of capacity costs for which each is causally responsible: it is consumption at that time that determines how much capacity the utility must have available. The system's load factor might well be improved by inducing individual customers to cut down their consumption to a deep trough at the *system* peak and enormously increase *their* peak utilization at the system's off-peak time: yet the noncoincident demand [charge] system would discourage them from doing so."

Alfred E. Kahn, *The Economics of Regulation*[91]

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[91] Kahn, A. E. (1970). *The economics of regulation: Principles and institutions* (Vol. 1), p. 96. John Wiley.

[92] This means that demand charges are priced on a kWh-per-hour basis instead of a true kW measurement.

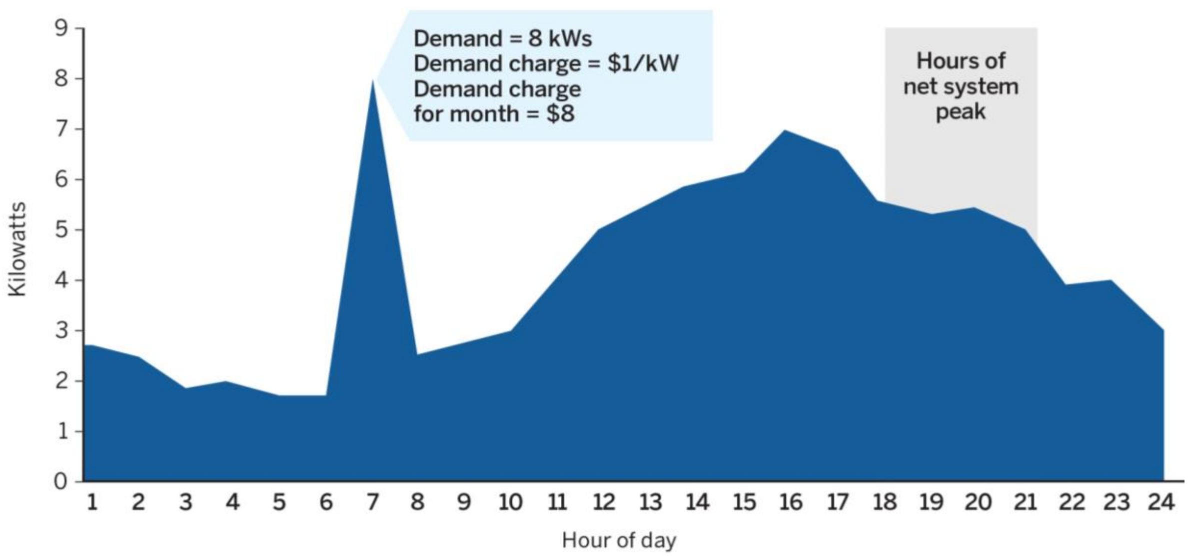
[93] See LeBel, M., Weston, F., & Sandoval, R. (2020, November 5). *Demand charges: What are they good for?* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/demand-charges-what-are-they-good-for/

The following subsections describe five types of demand charges seen in the United States.

Traditional Billing Period Individual Noncoincident Peak Demand Charge

The most common form of demand charge is one that is assigned to a customer's individual peak demand during a billing period, which is referred to as the customer's noncoincident peak. This customer NCP might or, more likely, might not coincide with the overall system peak or any other time that drives shared system costs. Figure 18 illustrates this for a residential customer.

Figure 18. Illustrative monthly noncoincident peak demand charge for an individual residential customer



Because of the lack of clear correlation between individual customer peaks and the hours when usage drives system costs, demand charges have a relatively weak cost causation basis in the modern grid, where the costs of load shifting are declining and advanced metering enables numerous other options. However, demand charges have a better cost causation case for the elements of the system with little or no load diversity.[94] As mentioned previously, shared line transformers and other local distribution infrastructure will have less diversity of load than distribution substations, transmission systems and the regional generation system. Furthermore, dedicated transformers and dedicated service lines are naturally sized for individual customers, which can be impacted by that customer's NCP. For residential customers and small business customers, there are also significant questions about whether demand charges are sufficiently understandable and whether these customers can respond in an effective manner to manage their bills.[95]

[94] In addition, there can be more general benefits of limiting customer variability to the extent that a customer is able to respond in this manner.

[95] See Chernick, P., Colgan, J. T., Gilliam, R., Jester, D., & LeBel, M. (2016, July). *Charge without a cause? Assessing electric utility demand charges on small consumers.* Acadia Center. https://acadiacenter.org/resource/charge-without-a-cause/

Many monthly demand charges for large industrial customer classes are characterized by ratchets across billing periods — the mechanism by which a maximum demand in one period becomes the basis for minimum billed demand in subsequent periods. Ratchets of 80% are quite typical, for instance: Billing demand will be the greater of this month's noncoincident maximum load or 80% of the maximum in any of the previous 11 months. Once a maximum demand is hit, the customer has little incentive to reduce demand in the following periods. Unless individual customer peak is closely linked to the hours that drive system costs, there remains little incentive to minimize usage at the times it would be most beneficial to the system.

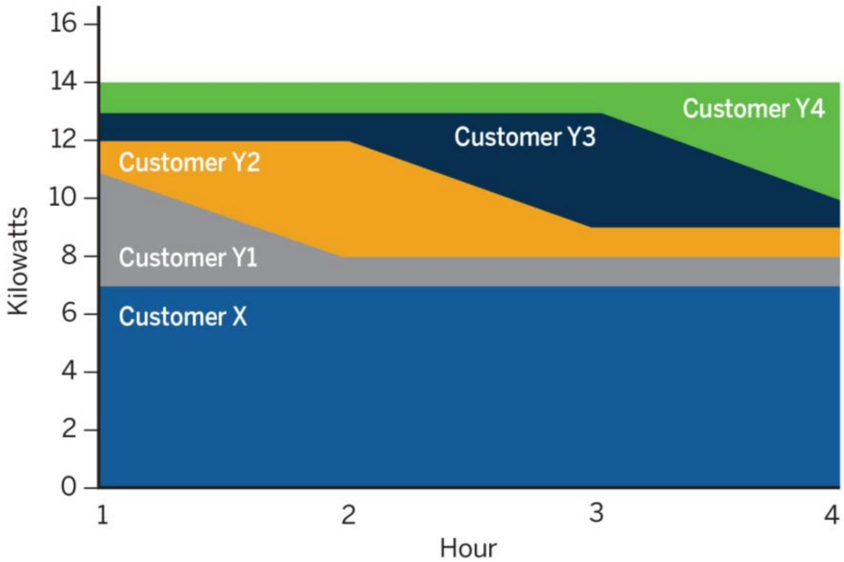
Peak Window NCP Demand Charge

A peak window demand charge is based on an individual customer's NCP within a defined multihour interval, similar to the on-peak period for a TOU rate. Peak window demand charges are an improvement over their traditional counterpart, insofar as they do a better job of relating the contribution of a customer's demand to system peaks and allocating costs accordingly to it, but they nevertheless do not solve some of the core deficiencies of demand charges as an efficient pricing mechanism. Time-varying rates, including TOU rates and critical peak pricing, are typically more efficient and fair than peak window demand charges for shared system costs for two related reasons:

1. The inefficiency of the ratchet that all demand charges impose, which incorrectly underprices usage in the rest of the peak window within the billing period unless individual customer peaks are strongly correlated with the hours that drive costs.
2. Unfair intraclass cost allocation, with those customers with demand diversity subsidizing those with more continuous usage.

This latter point can be illustrated with a hypothetical case of several smaller customers whose aggregate consumption adds up to the load of a single larger customer. Figure 19 on the next page shows such a case for a four-hour on-peak period.

Figure 19. Customer load comparison illustrating ability to share capacity



Customers Y1, Y2, Y3 and Y4 have, in the aggregate, the same load profile as customer X. Each of the Y customers has a peak of 4 kW for a total billing determinant of 16 kW under a peak window demand charge. However, customer X has a peak of 7 kW, which translates into a billing determinant of 7 kW under a peak window demand charge. This means that customer X is charged less than half the amount that the Y customers are for the *exact same aggregate load pattern*. The four diverse customers can efficiently share capacity and should not be penalized by a price structure that fails to account for their diversity. Furthermore, incentivizing the Y customers to flatten their load within this time period does not necessarily lower the combined peak of these customers, although it could remove the cost allocation differential between customer X and the Y customers.

Contract Demand Charge

A contract demand charge shares much in common with a subscription-based fixed charge. The most common form involves large industrial customers contracting with the utility for certain levels of maximum demand for a fixed price. Historically, some contract demand charges have been higher if they are expected to be incurred at peak demand time, with an appropriate discount for individual peak demand that occurs at off-peak times. As noted previously, Électricité de France provides a residential rate that includes a kVa subscription charge that strongly resembles a contract demand charge, although the categories of costs involved in this rate are much narrower than for a typical industrial contract demand charge.

Daily-as-Used Demand Charge

Daily-as-used demand charges are, as the name implies, a demand charge for a customer's individual NCP in a given 24-hour period, sometimes limited to a peak window within that day and sometimes excluding weekends and holidays. This means that the ratchet feature of a daily-as-used demand charge is reset every day and not every billing period, as with other demand charges (which is to say that it is, at most, a 23-hour ratchet). In New York, daily-as-used demand charges are used as a part of standby rates.[96] Daily-as-used demand charges applied to peak windows could be a further improvement on peak window demand charges for some purposes, and they could fluctuate according to system conditions. As such further refinements are made, however, such a system of narrowly applied demand charges converges on a system of time-varying energy (kWh) rates.

Standby Charge

A standby charge is typically an umbrella term for demand charges that are specially applied to C&I customers with distributed generation, sometimes termed partial requirements customers. Historically, many of these customers had large combined heat and power facilities. These customers were typically on rates that applied a traditional monthly demand charge and may have included an annual ratchet. If these facilities underwent maintenance for a single day, an outage would trigger a substantial demand charge for the month or even set their demand ratchet for the coming year, a result that is both inefficient and unfair. A number of jurisdictions have tried to address this by adjusting standby demand charges for the lower probabilities of coincidence with system peaks. The charges themselves are either reduced in some way, or the instances in which they are applied are more narrowly circumscribed. One example is the use of daily-as-used demand charges as an alternative to monthly standby charges, as described above. This approach recognizes that different customers with combined heat and power facilities are likely to have scheduled and forced outages on different days and therefore can share the capacity to provide their standby service. It also rewards customers for maintaining their on-site facilities and limiting outages.

B. Designing Credits

Although debates over rate designs for electric utilities go back to the early 20th century, defining export credit structures for DG customers, or DER customers more generally, is a much newer topic. From the inception of net metering, simply defined credit structures have been most common, but the potential variations and complexities are nearly endless.

Volumetric versus Monetary Crediting

When defining an export credit scheme, there is a threshold choice about how to define the relevant unit for a credit. When net metering was first established, many jurisdictions defined the credit by the number of kWh, which can be called volumetric crediting. If a customer had net excess generation of 100 kWh in May, those kWh credits would roll over and could be used to reduce billed kWh in subsequent months if that customer had net consumption. This would generally be true regardless of whether the kWh *price* changed in subsequent months because of seasonal rates or other factors. While this simplicity had its virtues, many jurisdictions have subsequently found volumetric crediting to be inflexible in many situations. For example, it can be difficult to change the value of the

[96] New York Battery and Energy Storage Technology Consortium. (2018). *Standby rate + Con Ed rider Q fact sheet.* https://cdn.ymaws.com/ny-best.org/resource/resmgr/energystorageresources/rider_q_pdf_final.pdf

credit if it is directly pegged to a kWh number,[97] and using volumetric crediting in the context of TOU rates also raises thorny questions.

As a result, many jurisdictions, including Michigan in its transition from legacy net metering to the DG program, have necessarily gone from a volumetric crediting scheme to monetary crediting. Under monetary crediting, any credits at the end of the billing period are defined by their dollar value in that period and can either be applied to other billing determinants within that same billing period (e.g., a customer charge) or rolled over to be applied in subsequent billing periods. There are often additional rules about whether and how monetary credits can be applied within the same billing period and how they get rolled over. The monetary value in the same billing period can also be different than the value that would be rolled over into subsequent months. Because of this additional flexibility, our discussion of credit design in this section and potential pathways in Section 6 assumes the use of a monetary crediting framework.

Methods for Setting Monetary Export Credits

A simple starting point for the definition of monetary credit value is a direct link to the retail rate. From an administrative perspective, this provides an easy reference for every customer class. As noted previously, Michigan is currently taking this approach by defining credit value at the supply kWh rate, with or without transmission costs depending on the utility. Other jurisdictions have linked credit value to retail rates in numerous different ways. Projects of different sizes in Massachusetts have long been eligible for different portions of the retail rate. Small DG installations were eligible for the full kWh retail rate, albeit excluding energy efficiency surcharges, but larger installations only received the supply kWh rate and the transmission kWh rate. Reforms implemented in New Hampshire several years ago set the residential credit value as the sum of the supply kWh rate, the transmission kWh rate and 25% of the distribution kWh rate.[98]

Linking credit values to retail rate structures can also be done with time-varying rates, as well as rate design elements other than kWh charges. When DG program customers in Michigan are allowed to opt into time-varying rates under the DG program, they have time-varying supply credits that follow the underlying time-varying supply rate. Several other jurisdictions have used this approach. Under the DG program, the MPSC is also defining a demand-based credit in reference to generation demand charges for some utilities' C&I rate classes.

Beyond the methods for setting export credit value in reference to retail rates, many jurisdictions have used a variety of methods for independently setting credit value. Historically, this included methods that were directly linked to wholesale market energy prices, such as a simple average wholesale price applied to credits generated in that

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97 Technically, a volumetric credit could be redefined as a percentage of a kWh to adjust its value. We are not aware of any jurisdictions that have attempted this approach.

98 New Hampshire Public Utilities Commission, Docket DE 16-576, Order on June 23, 2017, accepting settlement provisions, resolving settlement issues, and adopting a new alternative net metering tariff. https://www.puc.nh.gov/regulatory/Docketbk/2016/16-576/ORDERS/16-576_2017-06-23_ORDER_26029.PDF. In this order, monthly netting was kept for most bill elements, with the exception that nonbypassable charges would be charged based on gross inflows from the grid.

month. A very different approach was started nearly a decade ago by Austin Energy, a municipal utility in Texas. Under a buy-all/credit-all structure, gross solar generation is credited at an administratively determined value of solar (VOS) flat kWh rate, which included wholesale energy market value, generation capacity savings, transmission and distribution capacity savings, reduction in line losses, fuel price hedge value and environmental benefits.[99] Shortly thereafter, Minnesota adopted a similar flat kWh VOS tariff structure, which has only been applied to community solar projects to date.[100] Under Minnesota's structure, RECs are transferred from the customer to the utility because of the rationale that environmental benefits, represented by the REC, are part of the value-based compensation.

More recently, New York has implemented a sophisticated time-varying "value of distributed energy resources" (VDER) crediting structure for larger distributed generation and certain kinds of energy storage installations.[101] This VDER framework has evolved gradually since its creation in 2017. The following value-based credit structure is applied to hourly exports to the grid:

- Hourly wholesale energy market value.
- Generation capacity value, with alternative credit structures depending on the capabilities of a given technology.
- A general delivery avoided cost value and a location-specific adder for projects in areas with identified constraints.
- Environmental value for eligible technologies.
- A market transition credit, now transitioned to a community credit for community distributed generation.

Several of these VDER credit elements are time varying — namely, the hourly wholesale energy market value as well as the generation capacity value and delivery values for certain technologies. Other elements of the VDER structure are flat per-kWh credits, including the environmental value for eligible technologies.

As may be evident from the preceding descriptions, many of the credit structures that were developed independently from retail rates have focused on avoided costs or value-based methods. One component of the New York VDER structure has taken a notably different approach, with the original market transition credit and now community credit. The market transition credit was originally created to ensure that a category of projects that had a particular policy importance — namely, community solar projects intended to

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99 Rábago, K. R., Libby, L., Harvey, T., Norris, B. L., & Hoff, T. E. (n.d.). *Designing Austin Energy's solar tariff using a distributed PV value calculator.* Austin Energy; Clean Power Research. http://www.cleanpower.com/wp-content/uploads/090_DesigningAustinEnergysSolarTariff.pdf

100 Further information on Minnesota's value of solar tariffs can be found in Appendix B.

101 See New York State Energy Research and Development Authority. (n.d.). *The Value Stack.* https://www.nyserda.ny.gov/all-programs/programs/ny-sun/contractors/value-of-distributed-energy-resources. Mandatory application of the VDER tariff structure was initially applied to on-site projects for C&I classes with demand rates and two different categories of stand-alone projects connected directly to the distribution system, known as remote net metering and community distributed generation. Other customers are allowed to opt into this tariff.

provide an equitable distribution of solar program benefits — could continue without disruption, and it was structured to step down compensation gradually. As this market transition credit phased down and other issues with its implementation details became evident, the New York PSC replaced it with the community credit as a more stable way to meet these important policy goals.[102] This shows more generally how it is possible in many circumstances to incorporate other policy goals in the design of export credits.

Application of Credit Value and Rollover Provisions

Rules in different jurisdictions vary widely regarding how credit value can be applied to bills and even allocated across customers. The most permissive set of rules may be in Massachusetts, where nearly any customer that generates credits can file a form with the utility specifying how those credits should be applied to other customer accounts. New York also has permissive rules on this topic under the VDER tariff. The general theory is that the value of the credits does not change, and it is immaterial to other ratepayers how that value is applied to other customer accounts. Furthermore, this is a helpful way to provide flexibility for community solar programs to spread benefits to residential customers who cannot install solar on site or even certain kinds of C&I customers.

Most jurisdictions do have a variety of limitations on how credit value can be used over time or across customers. A common feature of many early net metering programs is known as an annual “cash out,” where any balance of credits is paid off to the customer, sometimes at a lower rate per kWh than the normal retail rate credit value. In other jurisdictions, credits may simply expire with no compensation to a customer. As Michigan policies in this area to date have shown, there are numerous other potential kinds of limitations, including the previous prohibition under legacy net metering on applying on-peak credits to off-peak consumption as well as limitations on whether generation supply credits can be applied to the distribution portion of the bill or the customer charge. Last, the value of credits can be different when used in the same billing period than their rollover value. This is part of the Duke Energy settlement in North and South Carolina, as further described in Appendix B.

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[102] See New York Public Service Commission, Case 15-E-0751, Order on April 18, 2019, regarding value stack compensation. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={06B07A5A-893A-48CB-BB0E-E8B3ABF4A7C6}

6. Reforms to Consider and Evaluation of Potential DER Rate Design Pathways

A. Defining the Key Issues

With at least four important rate-making principles and numerous additional policy goals for utility regulation, sorting through the key issues can be a challenge. We suggest four primary criteria, derived from long-standing regulatory principles, by which to evaluate DER rate designs:

- Fair cost allocation.
- Efficient customer price signals.
- Customer understanding and acceptance.
- Administrative feasibility.

This is not to imply that other principles and goals are unimportant but rather that other goals are less directly affected by DER rate design (e.g., it's likely that revenue stability would be significantly affected only in extreme cases) or require further quantitative analysis to determine (e.g., impact on DER-related jobs and industries). Progress toward the policy goal of societal equity, for example, is also possible through structural reforms. See the text box below for a discussion of equitable distribution of program benefits, particularly the potential for remedying inequity concerns through community solar.

Equitable distribution of program benefits

In some places with higher levels of distributed solar PV adoption, concerns have arisen that the customers adopting solar were primarily homeowners with above-average incomes and broader demographic characteristics that were not representative of the entire population. In particular, renters and other residents of multifamily buildings cannot generally install solar on their rooftops. While these concerns should be evaluated fairly, there are two ways of resolving them. One is to shut down program participation, but the other is to try to open the programs to broader public participation. This can be done through additional incentives but can also be achieved through more structural reforms. Introducing community solar, in which larger solar projects are separately interconnected to the distribution system and the utility credits subscribing customers, could be one such structural reform. Community solar customers enjoy a lower electricity bill but also make a monthly payment to the owner or operator of the community solar project, often having substantial overall net bill savings. Of course, if there are concerns about the crediting mechanism and levels for community solar projects, that raises another set of potential concerns, which was one of the significant motivations for the New York VDER tariff reforms.

In addition, it has been the case in many jurisdictions that commercial and industrial customers were also effectively prevented from meaningful participation in net metering programs, either because of size restrictions on projects or the fact that substantial demand charges for these classes meant significantly lower compensation through net metering. Reforming crediting mechanisms and other program rules to allow for comparable adoption levels by C&I customers is another way to promote an equitable distribution of program benefits.

The easiest reference point for comparing our three alternative pathways below is the current inflow/outflow method and framework used in the DG program in Michigan.

Fair Cost Allocation

The concept of fair cost allocation typically goes back to the foundational questions mentioned earlier around the principles of cost causation and costs following benefits. Although these principles are often applied at the stage of a rate case when costs are being divided up among customer classes, they apply equally to dividing up costs among customers within a class, sometimes called intraclass cost allocation. As may be evident, the question of cost causation is typically linked to efficient marginal cost pricing; we discuss this further below.

The broader principle of "costs follow benefits" is typically applied to categories of costs that do not have a direct cost causation basis related to customer usage or other characteristics. At a minimum, this includes A&G costs and any program costs primarily motivated by societal benefits (e.g., low-income discounts), albeit under two slightly different theories. A&G costs literally benefit all customers because none of the services provided by the utility could be carried out without those costs. Programs justified by societal benefits are somewhat different because the benefits are not directly related to utility service provided to customers. Instead, broad allocation of these costs, across and within customer classes, is about shared responsibility.[103] In both these cases, there is not an economically correct division of costs.

A more complex case arises in regard to elements of the electric system that do not necessarily have a direct cost-causation link to customer behavior, such as the "minimum-sized distribution system" referenced in the Bonbright quote on Page 41 of this report. These costs vary most directly with the size of the area the system covers or length of the lines, a factor that is not simple to include in rates; the practice of postage stamp rates generally prohibits including it. However, there is an important sense in which different customers benefit from this distribution system backbone in proportion to their usage. With the further development of DERs and with more customers exporting to the grid, the best way to think about this phenomenon may be changing in the modern grid. In other words, the distribution system may no longer be built simply to ensure deliveries and sales, but also to support bidirectional flows.

Efficient Customer Price Signals

The principle that prices should send efficient signals to customers has long applied to customer usage, and in a modern grid this concept must be extended to a customer's ability to store and generate electricity. According to microeconomic theory, prices are most efficient if they reflect marginal costs, although this statement glosses over many theoretical difficulties and practical disputes. For example, some analysts prefer to consider only short-run marginal costs, particularly locational marginal prices in wholesale energy markets. The better perspective is to include long-run marginal costs of

[103] For this reason, some analysts and academics prefer that many costs should be paid for through the tax system — although this answer is frequently unrealistic and may have other downsides.

generation, transmission and distribution capacity, as these costs are ultimately caused and justified by customer usage, generation and storage optimization choices. It is also generally the case that maximizing societal well-being requires the inclusion of externalities as a marginal cost. This can justify a higher assignment of residual embedded costs to certain pricing elements or the overall assessment of program costs and benefits using the societal cost test. Of course, externalities are not included directly in the cost of service, except as motivation for certain programs and various costs the utility incurs. Furthermore, the consideration of externalities in pricing has other practical consequences, including distributional impacts.

The customer behavior factors that underlie marginal cost are often referred to as cost causation, as discussed previously. From the perspective of the electric system, an additional unit of energy exported from a customer has largely the same impact as an additional unit of reduced consumption or an additional unit of generation consumed behind the meter that reduces imports, at least until the point of substantial reverse flows on elements of the grid. The marginal emissions impact, with associated environmental and public health consequences, can, however, be different, depending on the emissions profile of the distributed generation. REC policy is one way of accounting for these distinctions, which can be incorporated into DER rate design.

Cost causation, and the associated optimal marginal cost price structure, can be different for different elements of the electric system. Sending a monthly bill (either physically or electronically) has associated recurring costs that arguably fit into a customer charge. The broadly shared electric system fits well into a time-varying kWh pricing framework, although there are numerous disputes about how best to draw the connection between cost causation and workable pricing schemes. Service lines, secondary voltage lines and line transformers are mixed cases where the best proxy is subject to significant uncertainty. Depending on one’s assumptions about cost causation at this part of the system and trade-offs with other rate-making principles, these costs could be best recovered through customer charges, demand charges or kWh rates.

All deviations from efficient marginal cost pricing produce “inefficient” behavior, and any real-world pricing scheme will reflect such deviations for at least two reasons: (1) marginal cost pricing, regardless of someone’s preferred definition of marginal cost, virtually never matches the cost-of-service revenue requirement and (2) in most cases, proxies for marginal cost are often necessary instead of more precise and accurate pricing schemes, particularly for smaller and less sophisticated customers. In either case, deviation of pricing from marginal costs will cause distortionary behavior from customers, at least compared to the theoretical optimum. This is true regardless of the pricing element where a deviation is applied. For example, customer charges that are higher than marginal cost provide an inefficient incentive for customers to avoid those charges, either through formal or informal master metering or outright disconnection from the electric system. The latter possibility, also known as grid defection, was traditionally held to be unlikely, but continued cost declines for solar and storage, along with the availability of other backup generation options, may make it economically feasible for some customers in the near future. Extremely rural customers and specialized end uses (e.g., crosswalk lights and highway signs) that used to be connected to the grid have already defected to solar and storage in many places.

Customer Understanding and Acceptance

The criterion of customer understanding and acceptance for residential customers covers several related issues. To begin, basic principles of fair play in a modern marketplace dictate that customers understand what they are paying for and why. Any differences compared with what their friends and neighbors are paying should be intuitive and explainable without recourse to jargon impenetrable to the public. Furthermore, many customers are making choices within an overall budget and would like to know their options and how they can save on electricity or other utility bills.

There is also a meaningful sense in which customer understanding impacts the effectiveness of price signals built into electricity rates. Price signals can only work as intended if customers are able to respond to those incentives. Customer education, gradual introduction of reforms that build on each other, and understandable rules of thumb (e.g., consume less on hot summer afternoons) are all helpful tools to improve customer response. More sophisticated tools and efforts are possible as well. Online data provision, automated energy management technology and storage, and the availability of third-party aggregators or other energy management companies can all augment a customer's capabilities.

Administrative Feasibility

Typical utility rate-making practices across the United States today are already fairly lengthy and resource intensive, with significant administrative costs throughout the process. Introducing reforms into this process can be resource intensive as well, including the cost of new types of proceedings and new analytical requirements. Smaller reforms that make gradual changes to existing processes are likely easier to manage with little incremental costs once a clear decision has been made. However, major reforms that make serious improvement to the efficiency and equity of programs or rate structures can have benefits that justify the administrative costs. In any case, weighing these implementation concerns is important to make sure that reforms are implemented well and are not an unnecessary and unfair burden on implementing agencies or any of the stakeholders.

B. Data Collection, Customer Class Definitions and Cost Allocation Reforms[104]

Reforms to cost allocation processes can be important in their own right, but smarter and more robust analysis used in the cost allocation step can be carried over into rate design. There are two preliminary issues before major cost allocation and rate design decisions can be made: (1) the availability of relevant data on customer load, system load and costs and (2) the definitions of the relevant customer classes and subclasses.

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[104] Significant portions of Section 5.B are derived from Lazar et al., 2020.

The customer load and system usage data available to a utility with advanced metering infrastructure goes far beyond what was possible a generation ago. Utilities previously had to sample customers with more sophisticated metering to create class-level estimates. Similarly, utilities could put different kinds of metering on different elements of the system, but gathering more information always came at a cost. Now the bigger challenge is to store, process and protect the vast quantities of customer and system data that are available. Investor-owned utilities in the United States generally follow the FERC Uniform System of Accounts to track their costs, but many cost allocation methods and rate designs benefit from refinements to this general framework. The MPSC could consider working with the electric utilities to collect and track different kinds of expenses and investments in a disaggregated manner, including by voltage level and, where relevant, customer class.[105]

Another area for potential exploration is the definition of customer classes. Some utilities have more than one residential rate class or, alternatively, multiple residential subclasses, and the distinctions are often based on technology-driven class usage characteristics caused by end uses such as electric space heat, water heat, vehicles and solar installations. However, singling out customers based on technology adoption has serious practical and theoretical downsides. Furthermore, addressing one minor cost distinction is likely not fair or efficient if several other major cost distinctions are not addressed. It is wiser to consider multiple customer and service characteristics simultaneously to create technology-neutral classes for both cost allocation and rate design purposes. Some jurisdictions have separate residential classes or subclasses based on significantly different cost profiles, such as customers with and without electric heat. In many cases, these cost distinctions could also be addressed through rate design reforms. To continue with the example of electric heating, the distinction between residential customers with and without electric heat could be captured through seasonal rates, thus lowering or eliminating what could otherwise be an intraclass cross-subsidy without separating these customers into two different classes or subclasses. Dividing up customers by class can also have rate design implications because different rate structures are used for different customer classes. For example, residential customer classes generally do not have demand charges today, but most large industrial classes do.

Although improving cost distinctions by adding customer classes is a laudable goal, countervailing considerations may dictate keeping the number of customer classes on the smaller side. First, there are administrative and substantive concerns around adding rate classes, both in litigation at state regulatory commissions and in real-world implementation. Some potential distinctions among customers may be difficult to implement because they involve subjective and potentially controversial determinations by on-the-ground utility personnel. In creating new distinctions, regulators, utilities and stakeholders must all have confidence that there are true cost differences among the customer types and that there will be little controversy in reflecting those differences in the rate designs and levels. Some analysts object to customer classes based on adoption of

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105 For example, Missouri utility regulators have included exploration of better cost tracking methods as a stipulation in rate case settlements with electric utilities. See Missouri Public Service Commission Docket No. ER-2019-0035, Corrected Non-Unanimous Stipulation and Agreement in Ameren Missouri Rate Case, February 2020, p. 16. https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=ER-2019-0335&attach_id=2020013839

particular end uses, although this may serve as a proxy for significantly different usage and cost profiles. Furthermore, some utilities and parties in a rate case may propose rate classes that effectively allow undue discrimination. If the proper data aren't available to scrutinize such claims, either publicly or for parties in a rate case, then this may allow an end run around one of the significant motivations for utility regulation: preventing price discrimination.

Elsewhere, RAP has made comprehensive recommendations to modernize cost allocation practices.[106] Since the MPSC currently uses an embedded cost allocation framework, it is a reasonable choice to remain in this basic framework. However, key insights from the marginal cost approach can be helpful to understand productive reforms for both cost allocation and the following step of rate design. Starting at the functionalization step, the best practice is to avoid collapsing costs into a narrow number of functions,[107] which risks losing crucial information needed in later steps of the process. A&G costs, billing and customer service, and public policy programs should be tracked separately from electric system costs. Any utility expenses and investments that provide benefits across multiple functions (e.g., DER program costs, certain utility-owned energy storage and smart grid technologies) can be functionalized at this step, but often detailed information on those costs will be needed at later steps in the process as well.

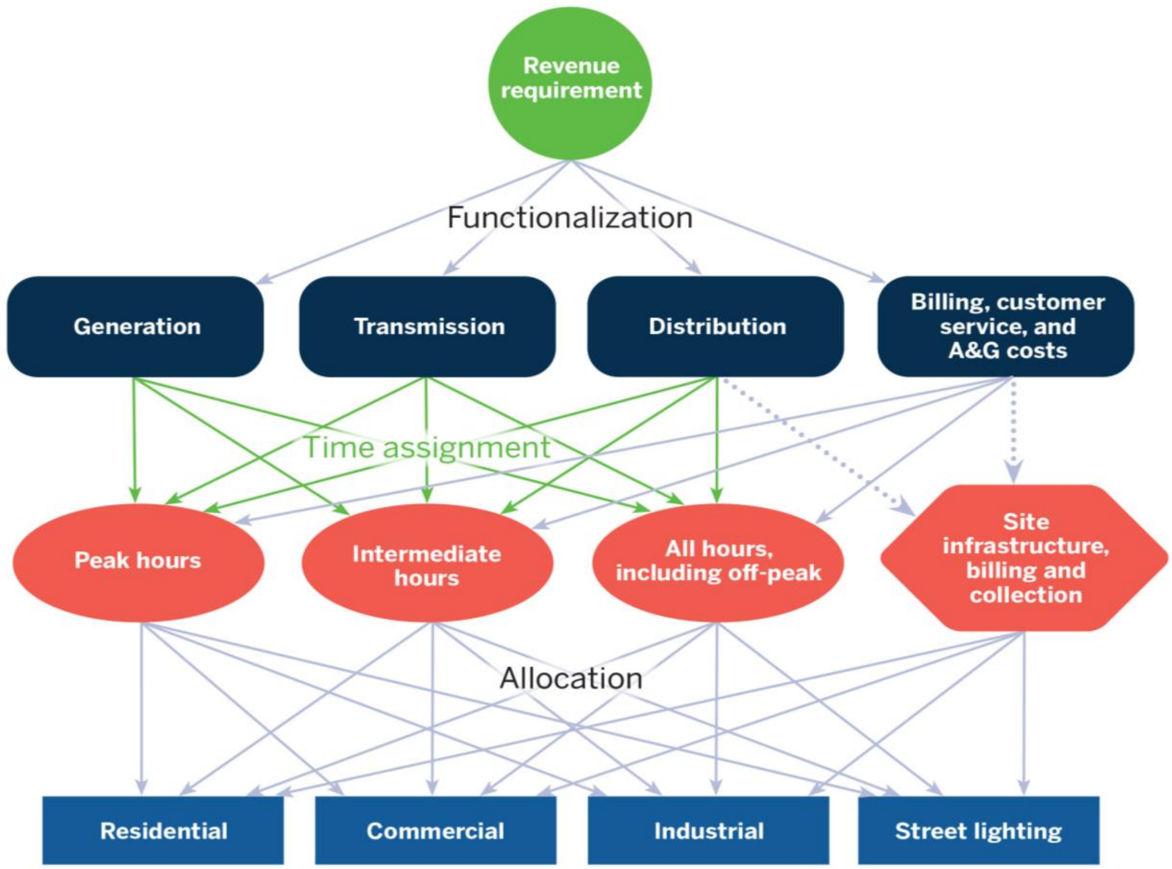
At the classification step, with improved information about class loads and with a range of new technologies, it may be appropriate to move past the traditional energy and demand classifications to create more granular distinctions.[108] Instead of dividing up shared system costs between the demand-related classification (generally intended to reflect system peak hours) and the energy-related classification (generally intended to reflect year-round energy usage), more granular time-based classification methods are possible. Costs that are typically placed into the energy-related classification, such as fuel and purchased power costs, would follow the same time-based classification scheme. Figure 20 on the next page shows a simple version of this.

[106] Lazar et al., 2020.

[107] In some sense, the functionalization and classification steps of cost allocation have lost some of their past importance because modern analytical tools (e.g., spreadsheets) can just continue to use the most detailed data available without any summary shortcuts. However, these steps still are relevant for other regulatory purposes, such as retail supply choice and thinking about cost causation.

[108] By statute, the MPSC has a presumption of treating production-related costs as 75% demand related and 25% energy related and treating transmission-related costs as 100% demand related. This statute provides that the MPSC may modify this method if it is determined that it does not follow the cost of service. See Michigan Compiled Laws, Section 460.11.

Figure 20. Modern embedded cost of service flowchart



The demand and energy classifications are replaced by a three-period time assignment scheme, although more sophisticated versions of this are also possible. A&G costs, site infrastructure costs, and billing and collection costs would be handled outside this time-based framework.

More specific recommendations include:

- Treat as customer-related only those costs that actually vary with the number of customers, generally known as the basic customer method.
- Recognize that advanced metering for any customer class no longer provides just customer billing data but rather a broader array of system planning and operational benefits.
- Collect and track distribution system cost data in a way that ensures reasonable calculation of class-level responsibility for site infrastructure.

- Allocate any peak- or demand-related costs for generation and transmission using a broad resource adequacy measure, such as the highest 100 hours or an hourly weighting based on a loss-of-energy expectation study.
- Ensure broad sharing of A&G costs across all classes and customers.
- Allocate the costs of public policy programs that benefit the electric system according to those benefits (i.e., who benefits and in which ways), but share broadly across all ratepayers other program costs justified by broader policy objectives.

C. Potential Pathways for New Rate Designs for DERs

Sections 4 and 5 discussed a wide range of options for overall program structure and rate and credit design. These different options can be combined into even more overall reform packages. We present three illustrative potential pathways in this section:

- **Gradual evolution pathway.** Modest improvements to the efficiency of pricing for new DG customers and overall rate design, along with associated cost allocation improvements, with a minimal need for new customer education efforts, process reforms or administrative burdens.
- **Advanced residential rate design for DERs pathway.** An aggressive effort to enlist a large segment of residential customers in more sophisticated time-varying rates on a default or mandatory basis to optimize their usage, storage and generation patterns to lower overall system costs while ensuring fair cost recovery with new rate structures. This effort may require significant new analysis and process reforms, as well as customer education and assistance with energy management.
- **Customer choice and stability pathway.** A simple and understandable set of options for customers that are fair to nonparticipating ratepayers, with stable payment schemes that may lower barriers for both customers and DER companies. This model requires significant administrative efforts to determine and update value-based credits and set the grid access charge.

These three potential pathways are not exhaustive and do not even use all the program elements discussed in Section 4 or every rate design and credit option in Section 5. However, they do present coherent frameworks to illustrate key principles and trade-offs. As policymakers and stakeholders consider the best path forward for DER rate design, and electric system reform more generally, we hope that this framing illustrates key choices and how to think about constructing overall reforms.

Gradual Evolution Pathway

Description

Customer Population Treatment

New residential DG customers, as well as customers with storage or EVs with vehicle-to-grid capabilities who wish to export to the grid,[109] are placed by default onto year-round TOU rates that are generally available to all residential customers. These customers cannot opt back into traditional volumetric kWh rates but may choose from other options. Other customers (with or without DG) are allowed to opt into this rate.

Legacy net metering and previous DG program customers are allowed to remain on their preexisting rate structures for 10 years from the time of interconnection. However, this baseline rate design may continue to evolve.

Metering and Billing Framework

Primary features of the current DG program model are maintained. Within each TOU period, inflow and outflow are billed or credited separately.

Key Rate and Credit Design Features

Import rates for these customers would be redesigned to be time-varying for both supply and distribution. Export credit value is set at the time-varying supply rate.

All residential customers have a monthly customer charge based on the basic customer method, plus tiered adders to recover incremental service line, secondary network and line transformer costs by type of customer: (1) multifamily building customers, (2) single-family building customers with panel sizes of 200 amps or lower and (3) single-family building customers with panel sizes over 200 amps.

Process Reforms

Process changes under this pathway would be minimal. Details of rate design would be improved by supportive analysis and cost allocation reforms. Implementing the tiered customer charge would require additional data collection to identify the appropriate category for each customer.

Evaluation

Fair Cost Allocation

Continuation of the inflow/outflow framework ensures that customers contribute to all the costs built into the retail rate for inflow, including public policy programs, A&G costs and all elements of the shared electric system.

The tiered customer charge adders for site infrastructure begin to reflect cost differences among customers with respect to the local elements of the distribution

[109] Customers with storage or vehicle-to-grid capabilities are only allowed to export to the grid with appropriate interconnection approvals.

system and improvements to time-varying rates improve allocation of costs of the shared system.

Efficient Customer Price Signals

Improvements to time-varying rates for new DG customers encourage more efficient customer behavior for the broadly shared system. Tiered customer charges for site infrastructure provide a modest signal for certain long-term customer choices (e.g., panel size) and remove those costs from the kWh rates.

Customer Understanding and Acceptance

This option affects only a small subset of customers with modestly more complex time-varying rates. Introducing a tiered customer charge for all residential customers is simple mathematically but may require customer education regarding its purpose and cooperation to identify the right category for each customer.

Administrative Feasibility

The process for this option is relatively simple, with a potential exception for categorization of the tiered customer charge. Details of new rate design reforms would require stakeholder discussion and potential litigation of the details in a rate case.

Advanced Residential Rate Design for DERs Pathway

Description

Customer Population Treatment

The residential customer class will be divided into two subclasses: advanced and basic. All customers with DG, EVs or storage or whose usage is higher than the 75th percentile are required to take service in the advanced residential subclass.[110] Customers with relevant resources (DG, battery storage and EVs with vehicle-to-grid capabilities) can elect to export to the grid with appropriate interconnection approvals.

Metering and Billing Framework

This option eliminates inflow/outflow billing within time periods and instead nets imports and exports within each pricing time period for customers who export.

Key Rate and Credit Design Features

A system of time-varying marginal cost kWh charges and credits is paired with three rate elements for cost recovery only. The time-varying charges and credits for generation, transmission and distribution should vary by season and include at least three TOU periods and critical peak pricing in all months with an expectation of potential resource adequacy issues. Customers with eligible generation

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110 Low-income customers are placed in the basic subclass by default, and all customers in this class can opt into the advanced subclass. Rate structures for the basic subclass should remain simpler than the rate design described for the advanced subclass.

technologies can receive an environmental value for exported energy, contingent on transferring the RECs to the utility.

The three cost recovery elements are (1) a customer charge defined by the basic customer method, (2) an individual NCP demand charge to recover site infrastructure costs (service lines, secondary networks and line transformers) and (3) a distribution flow charge on both imports and exports to recover nonbypassable charges and a portion of shared distribution system and A&G costs.

Process Reforms

Significant process reforms and additional analyses would be necessary to implement this option, including new time-varying marginal cost studies for transmission and distribution, the setting of environmental values in exchange for RECs, and stakeholder discussions to properly define a demand charge for site infrastructure and a distribution flow charge.

Evaluation

Fair Cost Allocation

Moving away from the inflow/outflow framework is justified by two new cost recovery mechanisms to ensure equitable contributions from these customers: the demand charge to cover site infrastructure; and the distribution flow charge for nonbypassable charges and a portion of shared distribution system and A&G costs.

The price signal built into the demand charge serves as a proxy to fairly split the costs of site infrastructure, and the granular time-varying rate spreads the costs of the shared electric system.

Efficient Customer Price Signals

This option presents a big jump forward in the efficiency of the price signals sent to a significant portion of residential customers, enabling more efficiency in the electric system and potentially significant long-term cost savings. The demand charge for site infrastructure provides a proxy to help manage local distribution costs and may result in modest additional benefits from encouraging customers to lower short-term load spikes and overall variability.

Customer Understanding and Acceptance

The complexity of this option and its application to a significant number of residential customers likely requires a substantial customer education effort, as well as clear explanations regarding the purpose of the new rates.

Administrative Feasibility

This option requires significant new analysis and process reforms that would require time and resources from relevant stakeholders and the MPSC. More complex rates also raise the risks of implementation difficulties for the utilities.

Customer Options and Stability Pathway

Description

Customer Population Treatment

New DG customers have a choice between two rate options: Choice A is a buy-all/credit-all structure, and Choice B is a significantly modified version of traditional net metering. Preexisting customers with DG are allowed to opt into one of the new choices but are not allowed to switch back.

Metering and Billing Framework

Under Choice A, all gross generation is metered and credited separately from consumption. Under Choice B, inflow/outflow measurement is eliminated, and monthly netting is used instead.

Key Rate and Credit Design Features

Under Choice A, customers receive a value-based credit on all gross generation, set as described below, and retail rate design may be changed separately from generation credits. Under Choice B, customers receive a value-based credit for net excess generation as determined by monthly netting. In addition to other retail rate charges, Choice B includes a grid access charge per kW of installed capacity to recover nonbypassable charges and a share of distribution system costs.

For both choices, flat kWh credit values for solar PV and other nondispatchable technologies are set administratively every two years based on an estimated long-term value of the resource. Customers can lock in their credit levels for 20 years or have their credit value updated over time. Customers receive the environmental compensation values only if they transfer the RECs to the utility.

Process Reforms

The primary process reform necessary for this pathway is adoption of an administrative structure to determine the value-based credits for distributed solar PV and potentially other technologies. In addition, significant stakeholder discussion may be necessary to define the grid access charge for Choice B.

Evaluation

Fair Cost Allocation

Under both choices, moving away from the inflow/outflow framework is justified by different changes to the framework. Under Choice A, it is inarguable that customers are paying for all of the costs built into their retail rate, which is separate from the credit for gross generation. Under Choice B, the grid access charge is intended as a proxy for nonbypassable charges and an equitable contribution to the costs of the distribution grid.

Efficient Customer Price Signals

Flat kWh value-based credits provide a reasonable rationale for whether a customer investment is worthwhile to the system, but this option provides little improvement for customer load management or storage operation directly. There is no barrier to the application of new retail rate structures for these customers over time, however.

Customer Understanding and Acceptance

Customer understanding under this pathway should be straightforward, but acceptance of the two options and potential differences among customers may need to be justified.

Administrative Feasibility

A significant administrative effort is required to set and update credit values. Practical details, such as treatment of storage, also need to be sorted out in this framework.

Appendix A: U.S. Energy Information Administration DG Adoption Data

Pursuant to correspondence with MPSC staff, Michigan utilities have continued to report DG tariff projects under the U.S. Energy Information Administration designation for net metering for the purposes of Form EIA-861M. However, other states with significant solar DG adoption levels may be reporting new DG tariffs under the "non net metering distributed" designation. This difference means that other states' data in these tables may be an undercount relative to Michigan's.

Table A-1. Distributed solar adoption by jurisdiction at end of 2020

Rank	State	MW AC	Rank	State	MW AC
1	CA	10,542	27	IA	135
2	NJ	2,160	28	IN	125
3	NY	1,801	29	NH	119
4	AZ	1,710	30	MN	106
5	MA	1,688	31	WI	103
6	MD	874	32	MI	99
7	FL	759	33	DE	92
8	CT	600	34	DC	84
9	HI	549	35	ME	72
10	NV	517	36	ID	61
11	TX	489	37	AR	58
12	PA	472	38	KS	31
13	CO	451	39	MT	25
14	IL	388	40	KY	22
15	UT	331	41	OK	19
16	SC	241	42	WV	11
17	MO	227	43	NE	10
18	NM	227	44	WY	9
19	WA	201	45	AK	8
20	OH	201	46	MS	6
21	NC	186	47	TN	1
22	RI	185	48	SD	1
23	OR	178	49	ND	0
24	VA	168	50	AL	NM
25	LA	156	51	GA	NM
26	VT	138			
				U.S. total	**26,657**

NM = Not meaningful (U.S. EIA terminology)

Data source: U.S. Energy Information Administration. (2021). *Form EIA-861M (Formerly EIA-826) Detailed Data.* https://www.eia.gov/electricity/data/eia861m/

Table A-2. Per capita distributed solar adoption by state

Rank	State	kW AC	Rank	State	kW AC
1	HI	0.376	27	IL	0.030
2	CA	0.266	28	WA	0.026
3	MA	0.240	29	MT	0.023
4	AZ	0.239	30	VA	0.019
5	NJ	0.232	31	AR	0.019
6	VT	0.214	32	MN	0.019
7	RI	0.168	33	IN	0.018
8	NV	0.166	34	NC	0.018
9	CT	0.166	35	WI	0.017
10	MD	0.141	36	OH	0.017
11	DC	0.121	37	TX	0.017
12	NM	0.107	38	WY	0.016
13	UT	0.101	39	AK	0.011
14	DE	0.093	40	KS	0.011
15	NY	0.089	41	MI	0.010
16	NH	0.087	42	WV	0.006
17	CO	0.078	43	NE	0.005
18	ME	0.053	44	OK	0.005
19	SC	0.047	45	KY	0.005
20	IA	0.042	46	MS	0.002
21	OR	0.042	47	SD	0.001
22	MO	0.037	48	ND	0.001
23	PA	0.036	49	TN	0.000
24	FL	0.035	50	AL	0.000
25	LA	0.034	51	GA	0.000
26	ID	0.033			
				U.S. total	**0.080**

Data sources: U.S. Energy Information Administration. (2021). *Form EIA-861M (Formerly EIA-826) Detailed Data.* https://www.eia.gov/electricity/data/eia861m/; U.S. Census Bureau. (2021, April 26). *2020 Census Apportionment Results*, Table 1. https://www.census.gov/data/tables/2020/dec/2020-apportionment-data.html; U.S. Census Bureau. (n.d.). *QuickFacts: District of Columbia.* https://www.census.gov/quickfacts/fact/table/DC/POP010220. Additional calculations by the authors

Appendix B: Key State Examples

A. Duke Energy Settlement in North and South Carolina

In September 2020, Duke Energy Carolinas and Duke Energy Progress reached an agreement with solar and environmental advocates in North and South Carolina to revise the tariffs offered to residential solar customers. The development of the agreement was largely in response to South Carolina's Energy Freedom Act (Act 62 passed in 2019) and North Carolina's House Bill 589 (passed in 2017). In May 2021, the South Carolina Public Service Commission unanimously approved the settlement.[111] The new compensation mechanism, called solar choice metering, is scheduled to apply to all new residential customers on or after January 1, 2022.

The agreement includes several key elements:

1. A minimum monthly bill of $30 for each solar choice metering customer. The agreement states that this is to ensure the utilities can recover estimated customer and distribution costs.
2. Time-varying pricing, including TOU periods and critical peak pricing, which will encourage DG customers to reduce consumption when prices are high. Customer energy imports and exports are netted within each TOU pricing tier, and monthly net exports are given a bill credit at the approved avoided cost rate. This credit can be used to reduce a customer's bill after the minimum bill has been applied. Critical peak pricing applies to imports during specified hours, and any energy exports during those hours are netted against peak imports.
3. A monthly grid access fee for facilities larger than 15 kW.
4. Nonbypassable charges for demand-side management, energy efficiency programs, storm cost recovery and cybersecurity costs.
5. A new incentive for qualifying solar choice metering customers to enroll in the proposed smart winter thermostat program. The agreement also includes a commitment on the part of the utilities to file a broader incentive program by June 1, 2022, that includes other peak load reduction technologies that can be paired with solar.

Utility proponents of the agreement note that cost recovery from solar customers will be fairer under this structure. Duke Energy estimated that this structure would eliminate 92% or more of the current cost shift from solar owners to nonsolar owners, and the utility will be able to charge solar customers more during peak demand times when most customers are drawing a lot of power from the grid. Solar proponents note that customers whose panels can send energy to the grid during peak hours will be properly compensated,

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[111] South Carolina Public Service Commission, Docket No. 2020-229-E, Order No. 2021-391 on May 29, 2021, establishing solar choice tariff for new customers beginning June 1, 2021. https://dms.psc.sc.gov/Attachments/Order/a69c88df-baf9-4e19-a789-affc2d006ee9

and solar customers will also be able to save money by participating in the peak load reduction aspects of the program.

B. California: From NEM 2.0 Toward NEM 3.0

California utilities have been obligated to offer a net energy metering tariff to their residential and commercial customers since the passage of SB 656 in 1995.[112] From the first tariffs in 1996 up through 2016, NEM was priced at the full retail rate with an annual true-up. Rate design in California during this period was an increasing block rate with TOU tariffs offered as an option. Each utility was obligated to offer the NEM rate to all customers on a first come, first served basis until a prescribed cap was met. The cap was initially set at 0.1% of peak load but was raised several times before settling at 5% of peak load. The maximum size of NEM eligible systems settled at 1 MW.

By 2013 utility-scale solar adoption was becoming significant in California. The combination of distributed solar approaching its 5% cap and the presence of thousands of MW of utility-scale solar contributed to the emergence of the duck curve at the California ISO. Assembly Bill 327 passed in 2013 to address a perceived disconnect between the compensation being provided to solar DG adopters and the value of solar DG to California's electric system. For the first decade of solar DG adoption, the electric system peak coincided with hours of peak solar production, making solar production valuable in addressing increasing peak loads. However, utility-scale and distributed solar collectively surpassed 20% of annual peak load, with utility-scale solar reaching 4,495 MW in 2013, while distributed PV approached its 5% cap. This dramatic increase in solar production caused the peak to shift from the afternoon to the very late afternoon and early evening. With solar production no longer coinciding with the electric system's peak and net peak, AB 327 mandated a reconsideration of the default NEM tariff, with the new default to become effective as the 5% cap was reached in the respective utility service territories.

The California Public Utilities Commission issued Decision 16-01-044 in 2016 to implement the NEM successor tariff, commonly referred to as NEM 2.0.[113] AB 327 specified some parameters for the revised NEM tariff, while others arose as the commission considered testimony and data from proceeding participants. AB 327 was concerned that NEM customers pay their share of nonbypassable expenses, which largely arise from public purpose programs incurring costs that utility ratepayers bear. These include programs like energy efficiency and low-income support. The issue of ensuring that solar adopting customers pay their share of system costs was addressed partly with this mandated feature and partly through additional features of the revised tariff, including:

- A mandatory interconnection fee.
- A minimum bill provision.
- The phase-in of mandatory TOU rates.

[112] The text of SB 656 is available at http://www.leginfo.ca.gov/pub/95-96/bill/sen/sb_0651-0700/sb_656_bill_950804_chaptered.html

[113] California Public Utilities Commission, Rulemaking 14-07-002, Decision on January 28, 2016, adopting successor to net energy metering tariff. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

NEM 1.0 customers were allowed to remain on that tariff, and NEM 2.0 customers were given a guarantee that their NEM 2.0 tariff would be available for 20 years.

Since 2016, solar has grown rapidly in California. By 2020, utility-scale solar had grown past 15,000 MW and distributed solar had surpassed 10,000 MW. The California ISO peak load is a bit less than 50,000 MW, so the 25,000 MW of solar is quite significant. In 2020, California utility regulators commissioned the *Net-Energy Metering 2.0 Lookback Study* to assess the performance of the NEM 2.0 tariff.[114] The study indicates that further changes in the NEM framework will be needed to address persistent cost shifting. Although commercial customers do not impose a cost shift, residential customers appear to significantly underpay their share of system costs. The California commission has launched NEM 3.0 to consider additional changes in rate and tariff design to address the cost shift and to better align rate design with cost causation.[115]

C. Arizona: Solar DG Export Tariff at the Resource Comparison Proxy

The Arizona Corporation Commission (ACC) directed its staff to begin rule-making to develop net energy metering rules in 2007.[116] The commission adopted NEM rules in 2008 that provided for annual netting where any end-of-year net kWh sales would be compensated at an avoided cost rate.[117] The avoided cost rate was defined to be "the incremental cost to an Electric utility for electric energy or capacity or both which, but for the purchase from the NEM facility, such utility would generate itself or purchase from another source."[118] On December 3, 2013, the ACC issued Decision No. 74022, which ordered that a generic docket be opened on net energy metering issues.

Docket E-00000J-14-0023 was opened in early 2014 to consider these issues. The ACC issued Decision No. 75859 on January 3, 2017, finding that NEM should be replaced with an instantaneous netting mechanism, known as the inflow/outflow model in Michigan, that compensates DG exports at the "actual value of DG."[119] NEM customers with an interconnection request that was filed before the effective date of the export credit tariff could remain with NEM for 20 years.

The ACC determined that the value of DG should be set at an administratively determined avoided cost and advanced two methodologies: the staff avoided cost methodology and the staff resource comparison proxy (RCP) methodology, as modified by the ACC. The staff avoided cost methodology specifies energy, generation capacity, transmission capacity and

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[114] For an evaluation of NEM 2.0, including a link to the study, see: California Public Utilities Commission. (n.d.-a). *Net energy metering (NEM) 2.0 evaluation.* https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/net-energy-metering/net-energy-meeting-nem-2-evaluation

[115] For the current status of NEM 3.0, see: California Public Utilities Commission. (n.d.-b). *Net energy metering rulemaking (R.) 20-08-020.* https://www.cpuc.ca.gov/nemrevisit/

[116] Pursuant to the federal Energy Policy Act of 2005 amendments to the Public Utilities Regulatory Act of 1978, the ACC began this proceeding to consider NEM as a so-called PURPA standard.

[117] See Arizona Administrative Code R 14-2-2301 through 2308.

[118] See Arizona Administrative Code R 14-2-2302(1).

[119] See Decision 75859 at ordering paragraph 133, p. 170.

distribution capacity, line losses and environmental costs at specified levels for five years.[120] The RCP methodology uses the five-year rolling weighted average of a utility's solar power purchase agreement and utility-owned solar generating resources with additions for the benefits of avoided transmission and distribution capacity investment and avoided line losses. The ACC specified that the inputs to the avoided cost methodology be updated every year and that the methodology be considered in full with each new rate case. The five-year duration was selected to reflect an expectation that a new rate case would occur approximately every five years.

Arizona Public Service implemented the RCP methodology through its RCP Rate Rider.[121] The rate rider specifies a 10-year rate (exceeding the initial five-year duration contemplated in the originating commission order) and carries the provision that the proxy will not decline by more than 10% per year. With utility-scale solar prices declining rapidly over the last five years, the 10% protection has proven important. For solar DG installed in 2017, the RCP is 12.9 cents per kWh. By 2021, the RCP declined to 9.405 cents per kWh.

Residential solar customers at Arizona Public Service have three TOU rate design options, two of which include a demand charge. Nonsolar customers have the same TOU options and two options that are not TOU.

D. Minnesota Value of Solar Tariff

Minnesota passed legislation[122] in 2013 that allows investor-owned utilities to apply to the Public Utilities Commission (PUC) for a value of solar tariff as an alternative to net metering and as a rate identified for community solar gardens. The 2013 legislation specifically mandated that the VOS legislation take into account the following values of distributed photovoltaics: energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value. The legislation also mandated a method of implementation whereby solar customers will be billed for their gross electricity consumption under their applicable tariff and will receive a VOS credit for their gross solar electricity production. To date, the VOS tariff has only been used for Xcel's community solar gardens, and no utility has opted in to use it for rooftop solar PV projects.

The Minnesota Department of Commerce was directed[123] to establish a calculation methodology to quantify the value of distributed PV. The department submitted the draft

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[120] See Decision 75859, Appendix A.

[121] See Arizona Public Service. (2020, October). *Rate Rider RCP partial requirements service for new on-site solar distributed generation resource comparison proxy export rate*. https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Residential/Renewable-Plans-and-Riders/rcp_RateSchedule.ashx?la=en

[122] Minnesota Session Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

[123] Minnesota Statutes, Section 216B.164, subdivision 10(e).

methodology to the Minnesota PUC in January 2014.[124] The PUC approved[125] the methodology at a hearing on March 12, 2014, and posted the written order approving the methodology, with modifications the Department of Commerce had approved, on April 1, 2014.[126]

VOS Methodology and Formula

To calculate a utility's VOS figure, several avoided cost components are each multiplied by a load match factor, if one is appropriate, and a loss savings factor. Adding the results of these separate component calculations produces the utility's VOS figure. As a final step, the methodology calls for the conversion of the 25-year levelized value to an equivalent inflation-adjusted credit. The utility would then use the first-year value as the credit for solar customers and would adjust each year using the latest Consumer Price Index data.[127]

There are eight components of value in the tariff:

- Avoided fuel cost.
- Avoided plant operation and maintenance — fixed.
- Avoided plant operation and maintenance — variable.
- Avoided generation capacity cost.
- Avoided reserve capacity cost.
- Avoided transmission capacity cost.
- Avoided distribution capacity cost.
- Avoided environmental cost.

There are two placeholder components: avoided voltage control cost and solar integration cost. These components are not part of the VOS calculation at this time, but the Minnesota Department of Commerce anticipates that these categories of costs and benefits will be known and measurable in the future.[128]

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[124] Norris, B. L., Putnam, M. C., & Hoff, T. E. (2014, April 1). *Minnesota value of solar: Methodology.* Minnesota Department of Commerce. https://mn.gov/commerce-stat/pdfs/vos-methodology.pdf

[125] In its order, the commission noted that unlike most proceedings arising under its jurisdiction, in this case the commission could not substitute its judgment for that of the department. Per statute, the commission could only approve the department's proposal, modify it with the department's consent or reject it. The commission limited its review to whether the department fulfilled its statutory obligations and reasonably justified the proposed methodology with regard to the public interest and in light of specific objections raised before the commission.

[126] Minnesota Public Utilities Commission, Docket No. E-999/M-14-65, Order on April 1, 2014, approving distributed solar value methodology. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bFC0357B5-FBE2-4E99-9E3B-5CCFCF48F822%7d&documentTitle=20144-97879-01

[127] Minnesota Public Utilities Commission, 2014.

[128] Minnesota Public Utilities Commission, 2014.

Some key characteristics of the Minnesota VOS policy include:[129]

- Investor-owned utilities may voluntarily apply to the PUC to enact a program in lieu of net energy metering.
- PV systems must be under 1 MW in size. Additionally, on-site production cannot exceed 120% of annual on-site consumption.
- Customer electricity usage is separate from production.
  - Customers are billed for their total electricity consumption at the retail rate.
  - Compensation for the solar system is through a bill credit, at the VOS tariff rate. Net excess generation is forfeit to the utility. The utility automatically obtains the solar REC.
- Value calculation:
  - It is production based and expressed in dollars per kWh, levelized over 25 years.
  - It is estimated as the combined value to the utility, its customers and society.
  - Value calculation process:
    - Once the VOS is established in any one year, that VOS is held constant for participating customers who install solar PV in that year.
    - The valuation will be updated annually for new VOS participants to incorporate utility inputs for the value of PV in the year of installation.
    - A utility-specific VOS input assumption table is part of the utility's application and made publicly available.
    - A utility-specific VOS output calculation table will break out the value of components and the computation of total levelized value and be made public.
  - A tariff is not an incentive, and it is not intended to replace or prevent incentives.
- The utility automatically obtains a solar REC with zero compensation to the customer.

Evolution in VOS Methodology Components

In 2019 the PUC updated the VOS methodology for the avoided distribution capacity cost component. Since 2017, the VOS has been used as the basis for the bill credit in Xcel's community solar garden program. In its May 1 compliance filing and its petition, Xcel argued that the current VOS methodology produces a VOS rate that is "unreasonable,

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[129] Key characteristics derived from Cory, K. (2014, October). *Minnesota values solar generation with new "value of solar" tariff.* National Renewable Energy Laboratory. https://www.nrel.gov/state-local-tribal/blog/posts/vos-series-minnesota.html; and Farrell, J. (2014, April). *Minnesota's value of solar: Can a Northern state's new solar policy defuse distributed generation battles?* Institute for Local Self-Reliance. https://ilsr.org/wp-content/uploads/2014/04/MN-Value-of-Solar-from-ILSR.pdf

unrepresentative, and clearly falls outside of the public interest." Xcel pointed to the avoided-distribution-capacity-cost component of the methodology as the cause for volatility in the VOS rate because the component used peak demand data to arrive at the capacity cost, and peak demand is volatile year to year due to variables such as customer requirements and weather. Xcel argued that a volatile VOS rate is confusing to customers and inaccurately represents the value of distributed solar to the system, which does not significantly change from year to year.

The PUC approved Xcel's proposal to move to a five-year average of per-kW distribution spending to calculate the avoided distribution cost for the 2020 VOS rate applied to the community solar garden program. The PUC also directed Xcel to file a framework showing how specific types of distribution projects will be categorized for future calculations of the VOS avoided-distribution-capacity-cost component. Finally, the PUC directed Xcel to discuss with stakeholders how the following could improve the VOS methodology: (1) long-term load growth assumptions, (2) sensitivity analysis of different time periods for systemwide calculation and (3) methods to de-average avoided distribution costs to account for specific location differences.[130]

[130] Minnesota Public Utilities Commission, Dockets No. E-002/M-13-867 and E-999/M-14-65, Order on December 3, 2019, approving changes to distributed solar value methodology as modified and requiring further filings. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={30D2CC6E-0000-CA1D-A52B-274566AF32CF}&documentTitle=201912-157987-01

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