

# **Report on the MPSC Staff Study to Develop a Cost of Service-Based Distributed Generation Program Tariff**

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**MICHIGAN PUBLIC SERVICE COMMISSION STAFF**

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## Executive Summary

In accordance with Sec. 6a (14) of Public Act 341 of 2016 (Act 341), the Michigan Public Service Commission (Commission) Staff has undertaken an in-depth study on the development of a new cost-based Distributed Generation (DG) tariff. In formulating its recommendations, Staff took consideration of all utility and stakeholder input, in addition to its own research and analysis.

In bringing its study to a close, Staff is recommending a conceptual tariff based on a new approach to billing DG customers called the Inflow/Outflow billing mechanism. The method separates *power inflows* from *power outflows*, relying on two distinct and independent sets of meter data to establish consistent and appropriate cost-of-service (COS) allocators *and* billing determinants, rather than netting the two as is done for net energy metering (NEM). This is a fundamental attribute of the Inflow/Outflow billing method.

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The use of bidirectional smart meters capable of independently metering and recording DG customer *inflow* and *outflow* is critical to establishing COS, as any netting of inflow with outflow obfuscates the true level of electric grid use by DG customers.

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Power inflow represents the accepted standard for measuring grid use by full requirements customers. Power inflows are, likewise, the correct measure of grid use by DG customers. Unfortunately, inflow data is missing from traditional NEM billing methods, as the energy netting concept was founded upon obsolete analog metering technologies for which bidirectional power flows were generally not available for COS analysis and rate design.

The separation of power inflows from power outflows readily allows for rate designs that incorporate traditional cost of service study (COSS) methods, thus ensuring that DG customers are assessed for their fair and equitable use of the grid. It also provides an independent framework for equitably compensating DG customers for excess power injected into the grid.

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The method's use of independently-metered power inflows and outflows as the basis for billing and compensation determinants also results in significantly increased price transparency over NEM.

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Having determined that the new cost-based DG tariff should be established upon the Inflow/Outflow billing mechanism, the study addressed the issue of whether separate COS rate schedules should be created in implementing the tariff. On this matter, the Staff study found that DG customers subject to the tariff should not be separated from full requirements customers for purposes of identifying cost-of-service (COS) customer classes. This recommendation is based on both the relative small number of DG customers in Michigan and the inherent class load-diversity as discussed in the report. As a result, the new cost-based DG program should be implemented through retail rate-schedule riders, as was done for the NEM program, rather than creating new and separate DG rate schedules.

In integrating the new Inflow/Outflow program into utility COSSs, it is recommended that for each COS class having customers that can participate in the program, that DG customer *inflow* be combined with full-requirement customer *inflow* to calculate the relevant class COS allocators. This would occur in utility general rate cases filed after June 1, 2018.

In contrast, existing NEM customers (that are grandfathered via Act 341 and Act 342) will continue to receive subsidized energy balancing services (for up to 10 years from their date of enrollment), as their net of inflow and outflow is used in the calculation of the relevant class COS allocators - matching the method of calculating billing determinants under the NEM billing mechanism.

The above COSS approach in the initial implementation of the new Inflow/Outflow billing mechanism allows the use of the underlying retail rate schedule to price power inflows by DG customers at COS. In contrast, electric choice customers will negotiate rates from their retail energy provider.

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Staff's study found that applying the underlying sales rates (energy, and demand if applicable) to billing determinants based on metered *inflow* resolves the critical deficiency of NEM, that distribution system infrastructure and maintenance costs are inappropriately shifted to non-DG customers.

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The Inflow/Outflow billing method is sufficiently flexible to accommodate alternate rate designs such as time-based pricing, or multi-part rates such as those including demand charges. It should be noted that if the underlying rate schedule includes demand charges, a DG customer's billing demand would be based on the customer's metered power inflows, not imputed total site usage. For example, if demand charges under the underlying sales rate schedule are based on a 15-minute interval measured during on-peak hours, then a DG customer's demand under that rate schedule is based on that customer's 15-minute inflow measured during on-peak hours.

It was further found that equity between full requirements customers and DG customers requires that DG customers not be subject to any other charges not applied to full requirements customers of the underlying COS rate schedule, such as fixed "grid" charges, or standby charges. Equivalent and non-discriminatory treatment for retail purchases by both full-service customers and DG customers ensures that DG customers are assessed no more and no less than their fair use of the grid.

Under an Inflow/Outflow billing method, project economics are strongly dependent upon power outflow compensation rates. Although Staff proffered what it believes is a fair compensation approach, crediting outflows at the PURPA avoided-cost established by the Commission for each regulated utility, the issue was controversial among workgroup participants. As a result, Staff determined it prudent to recommend that the Commission establish a new contested proceeding establishing a uniform *outflow*

*compensation method* for regulated utilities. The methodology approved in such proceeding would be incorporated into future general rate cases filed after June 1, 2018.

In summary, three key recommendations follow from the Staff's study:

(1) In any general rate case filed after June 1, 2018, utilities should be instructed to file the attached concept tariff-rider, which includes an Inflow/Outflow pricing mechanism as a foundational framework. The utilities may file additional proposals if desired. Any existing NEM tariff-riders would be amended to indicate that the NEM program is closed to new DG customers upon the effective date of the new tariff.

(2) Upon approval of the Inflow/Outflow concept tariff (on or before April 20, 2018), a new contested proceeding should be established by the Commission to set a uniform *outflow compensation method* for all regulated utilities.

(3) If the Commission adopts the Inflow/Outflow concept tariff as recommended by Staff, all rate regulated utilities should be ordered to file a report, within 60 days, describing their ability to meter and bill according to the Inflow/Outflow mechanism, and incorporate time-based rates for both power inflows and power outflows. Utilities should provide an estimate of the cost to modify billing infrastructure, if necessary, to accommodate the new tariff.

## **I. Statutory Mandates related to a Cost-of-Service Based Distributed Generation (DG) Tariff**

With respect to authorizing the Commission to approve a cost-of-service based DG program tariff, Sec. 6a (14) of Act 341 of 2016 directed the Commission as follows:

Within 1 year after the effective date of the amendatory act that added this subsection, the commission shall conduct a study on an appropriate tariff reflecting equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL

460.1001 to 460.1211. In any rate case filed after June 1, 2018, the commission shall approve such a tariff for inclusion in the rates of all customers participating in a net metering or distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211. A tariff established under this subsection does not apply to customers participating in a net metering program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211, before the date that the commission establishes a tariff under this subsection, who continues to participate in the program at their current site or facility.

Act 341 envisions that the process of establishing a cost-of-service based DG tariff begins with the Commission undertaking a formal study. The Commission has directed the Staff to lead this study, and the Staff has convened a collaborative workgroup process to facilitate its analysis, as detailed in the following section of this report. The Staff has created a sample Inflow/Outflow “tariff” attached hereto as **Appendix A**. The Inflow/Outflow billing mechanism is recommended as the conceptual framework for establishing a DG program that equitably recovers the cost-of-service.

The Staff interprets the word “tariff” in Sec. 6a (14) of Act 341 as providing the Commission broad discretion in the type of billing mechanism established for the DG program, subject only to the requirement that such a tariff be “equitable” in the recovery of the “cost-of-service.”

Consistent with the provisions of Sec. 6a(14), Sec. 11 (1) of Act 341 provides that:

Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class. In establishing cost of service rates, the commission shall ensure that each class, or sub-class, is assessed for its fair and equitable use of the electric grid. ...

In addition, Part 5 of Act 295 of 2008 required the Commission to establish net metering programs for each rate-regulated electric utility. Act 342 of 2016 updates these provisions by requiring the Commission to, within 90 days of the effective date of the act, establish a distributed generation program. Section III of this report describes the Commission’s efforts to comply with this provision by implementing an interim DG program to remain in effect until newly established DG tariffs in compliance with Sec. 6a(14) of Act 341 are adopted.



## **II. DG Program Workgroup (DG Workgroup) Process to Obtain Input on the Staff Study**

Staff convened the first DG Workgroup meeting in March 2017 and met seven times, with the final meeting held in December 2017. Cost of service considerations and development of the tariff were the primary areas of focus for the DG Workgroup, however, several presentations addressed technical interconnection matters including functionality of smart inverters, battery storage and microgrids.<sup>1</sup> Douglas Jester, Partner, 5 Lakes Energy<sup>2</sup> and Robert Rafson, President, Chart House Solar,<sup>3</sup> conducted separate analyses on a cost of service-based tariff and presented their findings to the DG Workgroup.

During the workgroup process, Staff requested comments on its concept tariff.<sup>4</sup> Nine sets of comments were received and posted on the DG Workgroup website.<sup>5</sup> Staff reviewed the comments and incorporated them where appropriate into the draft report.

Workgroup participants were invited to comment on a draft version of this report. All comments were reviewed, and revisions were made to the report as appropriate. However, this report is ultimately a Staff report and reflects Staff's recommendations and conclusions. Links to comments on the draft report and proposed tariff are provided in **Appendix B**.

## **III. Interim Distributed Generation Program**

In compliance with Sec. 173 (1) of Act 342 of 2016, on July 12, 2017, in Case No. U-18383, the Commission approved an interim DG program effective until it approved a

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<sup>1</sup> [http://www.michigan.gov/mpsc/0,4639,7-159-80741\\_80743-406256--,00.html](http://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406256--,00.html)

<sup>2</sup> [http://www.michigan.gov/documents/mpsc/20170815\\_DGWG\\_Presentation\\_597843\\_7.pptx](http://www.michigan.gov/documents/mpsc/20170815_DGWG_Presentation_597843_7.pptx)

<sup>3</sup> [http://www.michigan.gov/documents/mpsc/2017\\_DG\\_Tariff\\_presentation\\_Chathouse\\_603838\\_7.pdf](http://www.michigan.gov/documents/mpsc/2017_DG_Tariff_presentation_Chathouse_603838_7.pdf)

<sup>4</sup> [http://www.michigan.gov/documents/mpsc/DG\\_concept\\_tariff\\_603573\\_7.pdf](http://www.michigan.gov/documents/mpsc/DG_concept_tariff_603573_7.pdf)

<sup>5</sup> [http://www.michigan.gov/mpsc/0,4639,7-159-80741\\_80743-406256--,00.html](http://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406256--,00.html)

new permanent program and accompanying tariff as required by Sec. 6a (14) of Act 341 of 2016.

As described in Sec. 173 (1) of Act 342 of 2016, the DG program (and interim DG program) applies to all electric utilities whose rates are regulated by the Commission and alternative electric suppliers.<sup>6</sup>

Sec. 183(1) of Act 342 states:

A customer participating in a net metering program approved by the Commission before the commission establishes a tariff pursuant to section 6a (14) of 1939 PA 3, MCL 460.6a, may elect to continue to receive service under the terms and conditions of that program for 10 years from the date of enrollment.

The interim tariff approved by the Commission continued the existing form of net metering established by PA 295 to provide administrative continuity and reduce customer and supplier confusion, until the new tariff authorized by Act 341 was approved. The interim DG program and associated net metering billing methods are in the form of “true” net metering and modified net metering.

The Commission, in its July 12 order, recognized that approval of a new cost-of-service based tariff for DG under new statutory authority (Act 341) would necessarily institute a new regulatory platform for cost recovery that would reflect a fair and equitable use of the electric grid by such customers. The Commission noted consensus by stakeholders on this matter:<sup>7</sup>

All of the commenters agreed that continuing the current net metering program fulfills the requirements of Section 173 of Act 342 until new distributed generation tariffs are in place after June 2018. As UCS observed: It is clear that the Section 173 of Act 342 and Section 6a (14) of Act 341, when read together, direct the Commission to establish an interim distributed generation program (under Act 342) until it has approved and implemented a newly designed tariff under Act 341. However, Act 342 allows the Commission to “promulgate rules the commission considers necessary to implement this program”, giving the Commission broad discretion to consider the potential for administrative inefficiencies and customer and supplier confusion that may occur if the Commission were to require updated tariffs for each regulated utility in the near term and then a different tariff (under Act 341) at the conclusion of rate cases filed after June 1, 2018 - just one year later. Because we agree that these

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<sup>6</sup> MPSC rate-regulated utilities: Alpena Power, Consumers Energy, DTE Electric, Indiana Michigan, Northern States Power (Xcel), UMERCA, UPPCo and Wisconsin Electric (We Energies).

<sup>7</sup> <http://efile.mpsc.state.mi.us/efile/docs/18383/0022.pdf>

concerns are valid and significant, we also agree that the Commission would be within its authority to establish a distributed generation program that proceeds under a “business as usual” scenario until a tariff consistent with Section 6a(14) of Act 341 is approved through rate cases filed after June 1, 2018.

Act 342 explicitly addressed the issue of how existing NEM customers would be affected by the cost-based DG tariff. The Commission recognized this treatment in its July 12 Order approving an interim DG program.

Staff is aware that there may be some confusion regarding the language of Act 341, Act 342, and the above-quoted Commission order establishing an interim DG program, with regard to the cutoff for customers who qualify for the interim DG program, and going forward, those who must participate in the permanent new DG “tariff”.

In reconciling the language of the two statutes, the Commission found in its July 12, 2017 order in Case No. U-18383, on page 6:

“Again, recognizing the consensus among the commenters, the Commission agrees that under the plain language of Section 183(1) of Act 342, MCL 460.1183(1), any customer enrolled in the distributed generation program approved by this order may continue to net meter for 10 years from the date of enrollment. However, enrollment in the interim distributed generation program shall close on the date that an applicable distributed generation tariff is approved as part of any electric rate case filed after June 1, 2018.”

Since the order was issued, the Staff has received inquiries from stakeholders asking for clarification on what the Commission meant by “enrolled” when setting a cutoff point for net metering participation. More specifically, do the words “participating” and “enrollment” as used in Act 341 and 342 refer to the ‘submission of an application’ by a customer or ‘commencement of parallel operation’ or something in between?

Considering the length and complexity of the application approval process, there are pros and cons to each of these interpretations. Staff recommends that the Commission address this issue in a manner that creates the most equitable and least disruptive transition point for DG customers and the solar PV industry.

Should the Commission decide to seek comments on this point, the Staff proposes that “enrolled” for the purposes of Section 183(1) means that a customer has submitted a completed application to the utility for the interim distributed generation program.

The Staff believes that this approach is consistent with the interest in a smooth, equitable transition between the programs, as well as a provision of the current net metering rules set out in R 460.601a *et seq.* Such a provision *allows a completed application that is pending before the electric provider to be processed after the net metering program is closed* to new applications because of statutory program limitations. See R 460.644.

Under the Staff's proposal, upon the effective date of the permanent DG tariff, the interim NEM program will be closed to new applications. With respect to NEM applications submitted prior to that date, the utility will have 10 working days from the date the application is submitted to notify the customer that the application is complete or deficient. If complete, the application shall be processed, and the customer will be considered "enrolled" and permitted to continue to net meter for 10 years from the date the application was deemed complete by the utility. If the application is deemed deficient, the customer will be granted an opportunity to cure any defects. If the customer fails to cure the defects in the application within the time allotted, the application will be void.

#### **IV. "Inflow/Outflow" Billing Mechanism Analysis**

In compliance with Sec. 6a (14) of Act 341 of 2016, and the direction of the Commission, the MPSC Staff has undertaken a study on an appropriate DG tariff (reflecting an equitable cost of service) to replace the interim DG program using a net metering billing method approved by the Commission in its July 12, 2017 order in U-18383.

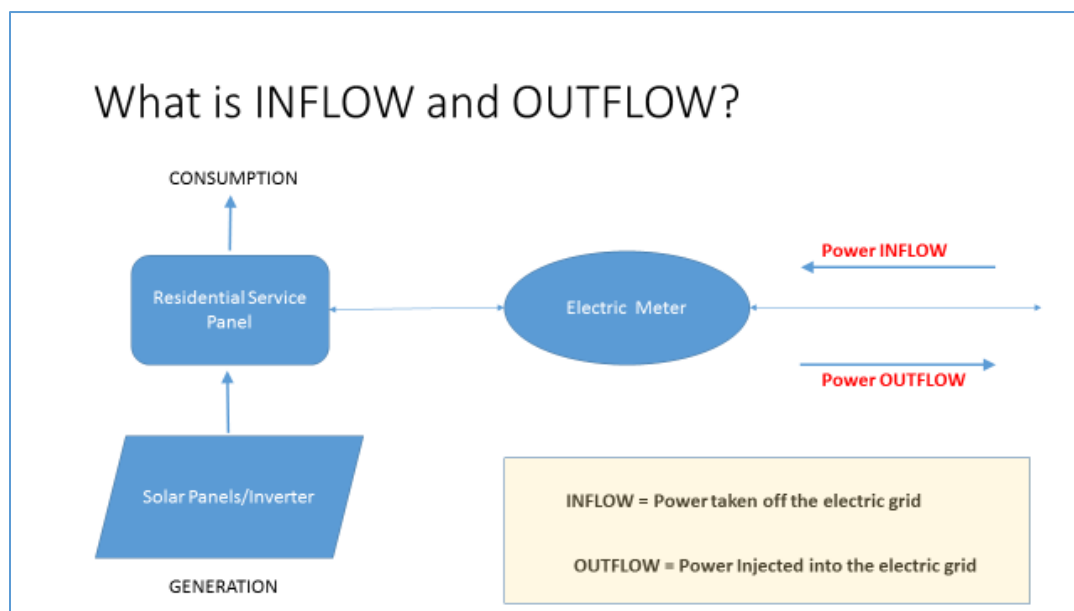
In forming its recommendation to the Commission, the Staff has relied upon on its in-depth analysis of alternate DG billing mechanisms, extensive computer modeling, cost-of-service analysis, and input from a wide array of stakeholders.

The form of DG tariff being recommended by the Staff is called the Inflow/Outflow billing mechanism. It is this conceptual framework that is recommended to be submitted by regulated utilities in any general rate cases filed after June 1, 2018, so as to implement cost-of-service based rates for DG customers.

Staff's recommendation is for a permanent structure to replace net metering. The Inflow/Outflow billing mechanism is a highly flexible platform for DG rate design. This is critically important, as Sec. 173(1) of Act 342 requires the Commission to approve a DG program "that shall be designed for a period of not less than 10 years."

The framework is simple, accommodates a wide array of potential future rate designs, such as those including demand charges, dynamic pricing, and dynamic credits. In addition, the Inflow/Outflow billing mechanism is transparent in effecting clear and accurate pricing signals, and thus can form the basis for future load-control and demand-response programs that target DG customers. It also provides a pricing platform for future implementation of customer-sited advanced energy-storage technologies, small-scale combined heat and power systems and potential new emerging technologies.

Rate designs that provide transparent and accurate pricing signals are a prerequisite for the fair monetization of the value of customer participation in demand response and load control programs and can help in providing a measure of a customer's financial payback for investment in technologies that allow for participation in such programs. The Inflow/Outflow billing mechanism satisfies this requirement.



Rate designs incorporating an Inflow/Outflow foundation have an advantage over other potential DG billing methods, in that both COS allocators and the billing/credit determinants coincide with the core parameters reflecting grid usage, i.e. the bidirectional power inflows and outflows. This attribute directly results in the high level of price transparency and accuracy of the Inflow/Outflow billing mechanism. These parameters can be independently measured and recorded by “smart” meters incorporated in utility Advanced Metering Infrastructure (AMI).

Because the billing determinants are consistent with cost causation, the Inflow/Outflow billing mechanism itself can provide equity of cost recovery, not only between DG customers who have diverse load characteristics, but also between DG customers and full-requirement customers of the underlying rate class.

The Inflow/Outflow billing mechanism also allows the full retail rate of the underlying sales rate-schedule to be used to price DG customer inflows, while ensuring that DG customers are assessed for their fair and reasonable use of the grid. This in fact is Staff’s recommended starting place for setting DG rates in the permanent DG program (authorized by Act 341) that replaces the interim net metered billing currently in place.

The following chart shows an example rate structure using metered power inflows and outflows as billing determinants where the rate schedule includes a demand charge.

## Inflow & Outflow Pricing Model

[Commodity and demand based rate-design]

Uses Inflow and Outflow to calculate the customer bill:

$$\begin{aligned} &\text{Customer Charge} + \\ & (kWh)_{Inflow} \times \left( \frac{\$}{kWh} \right)_{\text{Distribution \& Power Supply}} + (kW)_{Inflow} \times \left( \frac{\$}{kW} \right)_{\text{Distribution \& Power Supply}} \\ & - [(kWh)_{Outflow} \times \left( \frac{\$}{kWh} \right)_{\text{Value of Energy}}] - \text{Capacity Credit}_{Outflow} \end{aligned}$$

Based on Outflow, not Nameplate Capacity:

e.g.

$$ELCC \times Capacity_{Nameplate} \times Outflow_{Capacity Factor}$$

Because of the direct connection between the key parameter defining grid usage (power inflow) and (1) cost of service allocators and (2) billing determinants, separate and distinct rate-schedules for DG customers are not needed to meet the statutory mandate that rates recover a “fair and equitable use of the grid.” As a result, and in order to commence the new Inflow/Outflow billing mechanism that replaces net metering, only a retail rate rider (attached to the underlying sales rate-schedule) that defines the program rules and conditions is needed.

It is acknowledged that in future years, cost-of-service studies underlying general rate cases may be designed to allocate costs to specifically identified DG classes with corresponding unique rate schedules (or subclasses, with corresponding retail-rate adjusters). The long-term procurement of detailed *register* and *interval* data from the AMI system will facilitate both numerical analysis and decision-making supporting the cost allocation and rate design at such future time. This will enable the fine-tuning of rates, if needed.

It should be recognized that although quantification of specific rates was undertaken in the MPSC Staff study, this endeavor was undertaken only to understand the workings of various existing and potential DG billing methods and related cost-of-service study

(COSS) impacts. Actual rates for DG customers of individual utilities would be determined in future electric utility general rate cases.

Solar photovoltaic (PV) is the most critically impacted renewable-generation technology with respect to the structure of alternative billing mechanisms implemented under the DG program. For this reason, Staff focused its analysis on methods to quantify the economic impact to solar PV customers of various alternatives, including NEM, modified NEM, Buy-All Sell-All and Inflow/Outflow. Staff is confident that the Inflow/Outflow billing mechanism is the most reasonable method to ensure cost-based rates for DG customers going forward.

Economic analysis by the Commission Staff indicates that under the cost-based Inflow/Outflow billing mechanism, new DG customers will continue to see a positive net present value and economic payback of solar PV within the expected useful life of the generation systems (see **Appendix C and D**). Although customers will see higher monthly bills than under the prior NEM billing mechanisms, the difference is solely attributable to recovery of a DG customer's "equitable cost of service" and "fair and equitable use of the grid" as required by Act 341. For net-zero residential customers, the difference in average customer bills under the new cost-based Inflow/Outflow billing mechanism approach (vis-à-vis NEM) is approximately \$16.50 per month, or \$198 annually, assuming compensation for power outflows at \$0.10 per kWh per **Appendix E**.

Staff considered the option of complying with the statutory mandate for the DG program to recover the cost-of-service by adding a fixed grid-charge to NEM. Staff recommends against this approach for two reasons. First, it is difficult to accurately calculate a grid charge on a COS basis, since bidirectional power flows needed for a COS analysis are generally not available from NEM programs. This deficiency significantly impacts the accurate quantification of such grid charge. Secondly, NEM is unable to accommodate transparent and accurate price signals, since the billing determinants are nearly invariant to a customer's actual grid usage. These two issues are intrinsically linked. The matter is further addressed in Section VII of the report, **Appendix C**, and **Appendix D**.



It should be noted that Act 342 prohibits credits for net excess generation from reducing any grid charge. To this effect, Sec. 177 (5) of Act 342 states:

A charge for net metering and distributed generation customers established pursuant to section 6(a) of 1939 PA 3, MCL 460.6a, shall not be reduced by any credit or other ratemaking mechanism for distributed generation customers.

On the other hand, if the Commission were to adopt Staff's recommendation to implement a DG tariff based on the Inflow/Outflow billing mechanism, then all costs emanating from a DG customer's *fair and equitable use of the grid* would be fully recovered by the application of distribution charges (e.g. demand and energy based) to billing determinants based on the customer's metered power inflow. In this case, there would not be a need for any supplemental "grid charge" to recover the COS. Staff believes the Inflow/Outflow billing mechanism satisfies Sec. 175 (5) under any rate design construct, since no grid "charge" exists (or the grid charge could be thought of as being numerically equal to zero).

However, Staff is cognizant that Outflow credits could at times equal or exceed Inflow charges, resulting in a *de minimis* or negative customer bill. For this reason, Staff recommends that Outflow credits not be applied against the monthly customer charge, but rather be carried over to the next billing month. This ensures the utility will receive at least the monthly customer charge each month, and, that the DG program does not induce any income-tax liabilities for DG customers.

## **V. Credits for DG Customer Power Outflows**

One of the foundational objectives of the MPSC Staff's study is establishing a crediting mechanism for the customer credits for power outflows of generation not used by the customer on-site. It should first be noted that an outflow crediting mechanism (outflow is all kWh exported to the utility) differs fundamentally from crediting net excess generation (net excess generation is inflow – outflow) as part of NEM. The netting process, regardless of the netting interval, always results in a generation export that

diverges from the true level of export, and a retail purchase level that is inconsistent with the actual level of power inflows, and thus the true level of grid use.<sup>8</sup>

Having defined the primary DG regulatory structure (i.e. Inflow/Outflow billing mechanism using the underlying rate schedule for pricing power inflows), the associated methodology for valuation of DG customer power-outflows can be determined.

The compensation methodology is something that could change over time to meet evolving regulatory and policy objectives, although major changes in compensation methodology should be contingent on existing customers having an opportunity to lock in the prevailing rates/method for at least a 10-year period. This stability in compensation method is critical to supporting capital investment in distributed solar PV systems.

A fair valuation method for DG resources injected into the grid by DG customers consists of two parts: (1) an avoided capital and energy cost; and (2) all other avoided cost or benefit elements such as avoided distribution line losses, transmission and distribution costs, avoided air emission and environmental costs, the solar-fuel price hedge, and reactive supply and voltage control. Many DG workgroup stakeholders were also of the view that all avoided costs and other benefits must be included to set a fair compensatory rate.

Unfortunately, neither Staff nor any DG workgroup stakeholders have had the opportunity to rigorously quantify a total valuation. In addition, from a legal perspective, externalities having a high uncertainty of being incurred by a utility as a current or future expense may be difficult to assess and recover from customers ultimately receiving DG power outflows (e.g. full requirements customers). What is available at this time is a proxy generation plant calculation of energy and capacity, grossed up for avoided distribution line losses, and that value is approximately 10 cents per kWh (See **Appendix E**).

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<sup>8</sup> Some jurisdictions (e.g. California) refer to a DG billing method called “Net Billing”. The Net Billing method is structurally related to Modified Net Metering as defined in Act 342, Section 5 in that it involves a cash-out of net excess generation over certain intervals. The netting process inherent to the Net Billing method implicitly overstates the level of generation that is used onsite, thus masking the true level of grid use.

In its recent order considering PURPA rates for Consumers Energy, the Commission has recognized the validity of including other avoided costs along with the core capacity and energy compensation. Thus, one option the Commission could consider is to use such proceedings as the basis to set compensation under the Inflow/Outflow mechanism.

Compensation of DG customer power outflows at the avoided cost as established for power outflows of qualifying PURPA generators is an easy connection to make, considering that small DG facilities ( $\leq 150$  kW, methane digesters  $\leq 550$  kW) meet eligibility requirements as qualifying facilities under PURPA (although due to their small size, most are exempt from any federal filing requirements for qualifying facilities).

Currently, PURPA rates for the two largest Michigan utilities are calculated using a *proxy generation plant* methodology (i.e. a two-part hybrid proxy-plant model, whereby the value of capacity is defined by the capital cost of a simple-cycle gas turbine; and the value of energy, as selected by the qualifying facility, may be based on: (1) a wholesale rate (locational marginal price (LMP)) according to the time of delivery, (2) a forecasted wholesale price or (3) the forecasted variable operating cost of a natural-gas combined-cycle (NGCC) facility). All energy rates include an adder equal to the difference in capital cost of an NGCC facility and the capital cost of a simple-cycle gas turbine.

Staff believes that recognition of approved PURPA rates as a proxy for establishing DG program credits is administratively efficient, provides an equitable valuation of energy/capacity resources provided to the grid, and is fair to the balance of full requirements customers who pay for such resources as part of the utility's resource portfolio.

In addition, the use of avoided costs derived from the proxy generation plant model (as calculated in the PURPA proceedings) to set outflow credits is a logical approach considering that the DG program resources, in aggregate, provide a long-term power-supply resource, and thus can be considered a "virtual" power plant having a multi-decade operating life.

As the DG tariff is under consideration in utility rate cases filed after June 1, 2018, more information may be available to include pilot programs which incorporate locational pricing, load control, energy waste reduction and/or battery storage benefits into the outflow credit.

In addition, Staff notes that a material departure from the full retail rate that is implicit in the current *true* NEM program could have adverse impacts to the Michigan solar industry, DG market players and utility customers contemplating installation of solar PV systems. In this matter, the Commission could add an interim *market transformation* adder to the base avoided cost used to compensate DG customer outflow.

Although Staff proffered what it believes is a fair compensation approach, the issue was controversial among workgroup participants. As a result, Staff is recommending that the Commission establish a new contested proceeding establishing a uniform *outflow compensation method* for regulated utilities. In particular, this would give an opportunity to take a closer look at the issue of additional avoided costs and benefits (beyond energy and capacity) associated with DG power outflows into the distribution grid. The methodology approved in such a proceeding would be incorporated into future general rate cases filed after June 1, 2018.

Under this approach, there may be a possibility that a utility receives a Commission order in a general rate case filed after June 1, 2018, in which an order establishing a uniform outflow compensation method has not been issued in time to incorporate into the cost-based DG tariff approved in the rate case. In such cases, it is recommended that a interim compensation price for power outflows be set at the DG customer's power supply component of the retail rate.

In evaluating outflow compensation methods for DG resources injected into the grid, Staff had to resolve a core issue: whether credit for generation capacity/energy should be reflected on a class basis (i.e., outflow as a negative cost allocator in a COSS); or on an individual customer basis (i.e., as individual bill credits for DG capacity/energy available to the grid (per kWh or kWh & kW credit). The class credit approach was suggested by Douglas Jester of Five Lakes Energy. Mr. Jester provided a detailed

analysis during the Workgroup public meetings. His analysis included a per-customer-based COSS derived from Consumers Energy's most recent rate case (MPSC Case No. U-17990).

Although using outflow as a negative allocator in the COSS could be a viable valuation method that can be incorporated into an Inflow/Outflow based rate design, the approach has a downside, in Staff's opinion, with respect to initial implementation.

The "class" credit approach requires the COSS allocations for DG customers to be determined on a distinct DG class basis (separate and apart from full-requirements customers). This precludes the simpler COSS and rate design option of using the underlying retail rate as the charge for DG customer inflows. Nonetheless, Staff performed a COSS analysis of DG customers as a distinct customer class, which is covered in the next section.

## **VI. Commission Staff Cost-of-Service Analysis- 2014 NEM as a Distinct Customer Class**

Commission Staff undertook a cost-of-service analysis to compare the residential customer class as a whole to residential NEM customers as a distinct customer class, using 2014 numbers provided by DTE Electric Company. By way of background on how a cost-of-service study works, a utility makes investments in production, distribution, general and intangible assets. The total cost of these assets along with an allowance for working capital comprise the utility's rate base. The utility is legally allowed an opportunity to earn a return on its investment in rate base (minus that already depreciated) equal to its approved cost of capital. This is the utility's "return on" capital. Depreciation is the utility's "return of" capital. The utility also needs to recover its operating expenses and income taxes. The utility's revenue requirement should be sufficient to provide an opportunity to earn its return on and return of capital, as well as other operating expenses.

The utility's revenue requirement is recovered mainly through the amounts that it bills its customers. DTE has over 2 million customers and each customer is unique in the demands that it places on the system, and in the resulting costs that it causes the utility to incur to meet electricity demands. While each customer is unique, many customers

are similar enough to each other and dissimilar enough from other customers that they can be grouped together for the purposes of designing rates for that class. The main classes are the residential, commercial/secondary and industrial/primary classes.

This grouping of customers will necessarily result in much diversity between individual customers within a class. The electric use of a residential customer with a 12,000 square foot home will be different from a customer with a 2,000 square foot home. A residential customer with a 3,000 square foot home with no air conditioning will have a different electric demand than the equivalent customer with a 3,000 square foot home with air conditioning. Even so, there is likely less diversity between the customers in the residential class than there is when comparing a residential customer to an industrial customer. DG is one of the many items that causes diversity within a rate class.

The utility's total revenue requirement needs to be apportioned to each class. Rates can then be designed for that class to recover the revenue requirement for which it is responsible. The main tool used to apportion revenue requirement to the rate classes is a COSS. The first step in preparing a COSS is the classification of costs. This step involves sorting all the utility's costs and putting similar costs in the same cost bucket. This step is mostly accomplished through a utility's accounting system and the use of the uniform system of accounts where like costs are recorded in the same account number. These classified costs are then input into the COSS as rate base and revenue and expense elements. (For DTE this would involve about 300 inputs). Then each of these inputs is functionalized. This step requires splitting each input into two parts, either production-related or distribution-related. The result is a computation of a production and distribution revenue requirement. This step is important as some of a utility's distribution customers do not buy their electricity from the utility and are not responsible in the same way as a full-service customer for the utility's production revenue requirement.

The last step in preparation of a COSS is the assignment and/or allocation of the functionalized inputs to the rate classes. If a cost benefits only one class, it can be assigned directly to that class and that class is 100% responsible for its effect on the utility's revenue requirement. Most utility costs are indirect and benefit more than one

rate class. A judgment call must be made on how much each class contributed to the need to incur a cost that benefitted more than one class. This study group was comprised of many parties. As such, each party can look at the allocation of a given indirect cost and, using their best judgment, arrive at different allocation decisions, each of these decisions potentially having merit. One party might view the responsibility for causing a cost differently than another. One party might view the benefits and beneficiaries of a cost differently.

DTE uses over 60 different allocators in the allocation of its 300 COSS inputs. The starting point on the production side is the selection of the production allocator on which the majority of the production revenue requirement is directly or indirectly allocated. Act 341, Sec.11. (1) provides guidance. "The commission shall ensure that the cost of providing service to each customer class is based on the allocation of production-related costs based on using the 75-0-25 method of cost allocation and transmission costs based on using the 100% demand method of cost allocation. The commission may modify this method if it determines that this method of cost allocation does not ensure that rates are equal to cost of service."

The 75-0-25 ratio indicates that 75% of the production allocator would be based on a class's contribution to coincident peak demand measured in kW (total system-wide kilowatts of energy demanded during the hour of highest use). The other 25% of the production allocator would be based on a class's yearly energy use (inflow) measured in kWh (total system-wide kilowatt-hours used during the 8,760 hours of the year). While it is clear the Act allows for the Commission to select an alternative, for the purposes of this study, the currently approved 75-0-25 production allocator was maintained.

While the Act gave specific guidance for the allocation of production and transmission costs, only general guidance was provided for distribution. Not every customer class uses all portions of the distribution system. For cost allocation purposes, the distribution system is broken down into subsystems. The subsystem costs are allocated based on some measure of the rate class's contribution to that subsystem peak. These non-coincident peaks (NCPs) occur at different hours than the system peak (CP).

There are many methods to account for DG. The method chosen will influence the development of the distribution allocators. Staff chose the inflow/outflow billing mechanism. This method requires a COSS step and a step that is accomplished in the billing process. The COSS step would allocate distribution costs based on the energy customers pull from the grid (inflow) and how this energy use contributes to the CPs and NCPs. This will determine a class's distribution revenue requirement. The customers in a class would pay for the energy they consume and their contribution to peaks based on the rates developed from the COSS distribution revenue requirement. A separate mechanism (a billing credit) would be used to compensate the DG customer for all energy it puts back on the grid (outflow). The development of this credit is discussed in Section V of this report.

DTE prefers a different method for accounting for DG and developed distribution allocators on an inflow + generation – outflow basis. Under this method, outflow would be netted against inflow + generation in developing the distribution allocators in its COSS. Other parties have proposed additional methods. All the parties will have an opportunity to offer and debate their preferred method in future rate cases.

The results of Staff's COSS (based on DTE's 2014 inflow NEM data) indicate that on both the production and distribution side, a DG customer would be responsible for a lower total revenue requirement than a similarly-sized non-DG customer. This is intuitive as a DG customer would be using its own generation on some of the peak hours (CP and NCP) and would lower the peak measurement for the DG class. The following table shows the average hour of system peak use for the last 5 years for every month for both DTE and CE, with the summer months highlighted. While the system peaks during the summer months are well-aligned with solar production, other months are not.



<b>Monthly System Peak Hours</b> <b>(5-year average)</b>		
<b><u>Month</u></b>	<b>DTE</b>	<b>Consumers Energy</b>
Jan	7 PM	7 PM
Feb	7 PM	8 PM
Mar	6 PM	8 PM
Apr	11 AM	Noon
May	4 PM	3 PM
<b>Jun</b>	<b>4 PM</b>	<b>3 PM</b>
<b>Jul</b>	<b>4 PM</b>	<b>4 PM</b>
<b>Aug</b>	<b>3 PM</b>	<b>3 PM</b>
<b>Sep</b>	<b>3 PM</b>	<b>4 PM</b>
Oct	2 PM	5 PM
Nov	6 PM	7 PM
Dec	7 PM	7 PM

The production allocator is developed using the system peak for the months of June through September. On an average, for both DTE and CE, this system peak falls during the 3PM or 4PM hour when solar panels are generating power. The effect is the reduction of the DG contribution to the system peak for every hour used to develop the production allocator. This benefit is diluted for a distribution allocator developed using all 12 hours (12CP) as many winter system peaks occur when or after the sun is setting. DG solar does not shave the system in those winter hours, but the DG class would still benefit from an allocator based on 12CP due to the shaving of the peaks in the summer and shoulder months. Much of the distribution system is allocated on NCP allocators which are not shown in the above table. Though not necessarily the same in magnitude, the effect of solar would be in the same direction in reducing a DG portion of an NCP.

Even after meeting much of their annual electricity needs with their own generation, the average 2014 DTE DG residential customer still pulled more energy from the grid than the average non-DG residential customer. This suggests that the average 2014 DG customer is much larger (from an electricity use standpoint) than the rest of the residential class. As such, it is not meaningful to compare the average DG revenue requirement with the average residential revenue requirement as it would be comparing apples to oranges. The results of the COSS using Inflow data are shown in the tables below (the equivalent amounts for the non-DG customer are also shown due to the interest expressed by many parties):

Residential Inflow COSS Revenue Requirement per Customer

	<u>Production</u>	<u>Distribution</u>	<u>Total</u>
DG	\$545.40	\$574.14	\$1,119.54
Non-DG	\$646.88	\$515.71	\$1,162.59

Residential Inflow Deficiency (Sufficiency) per Customer

	<u>Production</u>	<u>Distribution</u>	<u>Total</u>
DG	(\$105.74)	\$67.50	\$(38.24)
Non-DG	\$ 11.61	\$13.73	\$ 25.34

When the DG customers are broken out into their own class in the COSS, The COSS shows that the average DG residential customer would be responsible for a production revenue requirement of \$545 and a distribution revenue requirement of \$569 for an average \$1,120 total annual revenue requirement. Assuming it were appropriate to split DG customers into their own class, on an annual basis, the DG customer would be allocated \$106 too much on the production side and \$68 too little on distribution side for a net annual overallocation of \$38. In addition to this annual revenue responsibility of \$1,120, the DG customer would receive recompense for the value of their outflow.

There are data availability issues with any approach of setting rates for DG customers that depends on separating DG customers into their own rate class for purposes of COSS and rate design. Due to the relatively small number of existing DG customers currently, and the high level of power-flow diversity within the small DG group, the use of limited historical data (of early adopters who are grandfathered net metering customers) to predict inflow and outflow profiles of DG customers that qualify for the new tariff is a questionable methodology.

Staff considers that a possible workaround to this problem is to substitute computer models (e.g. DOE *System Advisor Model*, NREL-*PVWatts*) to predict inflows and outflows on an 8760-hour basis. This would allow regulatory experts to perform a COSS that allocates costs/credits to the unique DG subclass, and to quantify rates under the Inflow/Outflow billing mechanism. This is the basic approach that Mr. Jester used in his analysis, and the approach Staff used in its modeling of various DG billing methods.

However, despite the fact that a reasonable analytical approach is available to create separate COS rate classes for DG customers, methods for setting DG rates that require withdrawing DG customers from the greater class-COS allocations in a COSS create a significant regulatory-policy inconsistency. Similarly, significant diversity between other full requirement customer subgroups has not been considered by the Commission as rising to a level that would justify the parceling out of the overall (e.g. residential class) into various subclasses.

For example, it is generally agreed that residential customers with air-conditioning have a distinctly different load (inflow) profile than non-air conditioning customers. The same with customers that work during the day vs. those that are at home all day, such as the elderly. In Staff's opinion, the differences between load profiles of other full requirement customer 'subgroups' are just as significant as the difference between the DG subgroup and average full requirement customers.

Staff strongly believes that separating existing COS rate classes into customer subgroups is a slippery slope that should be carefully considered so as not to harm the greater public interest. Separating customers having significant commonality into unique COS subclasses begs the question of when to stop the subdivision process. For

example, even within the DG subgroup, there can be large differences in load profiles that are a function of the level of generation capacity vis-à-vis total annual load. Further increasing the complexity of a potential class subdivision process is the expectation that DG customers may install energy storage systems that modify their load profile. The issue of when to stop the division process could become intractable once regulators move down that path.

As noted earlier, DG is only one of many items that cause diversity within a class. Currently in a COSS study, there are no separate classes for DG customers. Given that there are relatively few DG customers, COSS theory would not support splitting those customers into a separate class. DTE has just under 2 million residential customers of which DG customers number about 1,500. With a class composed of 2 million customers, the differences between individual customers are smoothed out and reasonable rates can be designed. There is a legitimate concern that if a COSS class is created for a relatively small group of customers because they have the DG characteristic in common, other non-DG characteristics that they do not have in common could result in rate design that adversely affects some of the customers within the class.

## **VII. Concerns with the Ability of NEM to be able to Recover Costs for Customers' "Fair and Equitable Use of the Grid"**

NEM at its core is a *billing method*, and thus a form of *rate design*. True net metering provides for a (kWh) netting of the bi-directional flow of energy during each monthly billing period, or time-of-use period, with a kWh carry-forward of the cumulative excess generation to the next period. In effect, true net metering can be thought of (approximately) as applying the full retail rate of a customer's underlying rate schedule to net excess generation. In contrast, modified net metering provides for a cash-out of net excess generation at a rate less than the full retail rate. Pursuant to PA 295, the cash-out of net excess generation, under modified net metering, was restricted to the average locational marginal price (LMP) (during the billing period or time-of-use pricing period) or the power supply component of the full retail rate, and this was carried forward in Sec. 177 (4) of Act 342.

Because, true net metering as it has been traditionally implemented, does not recover the fair and equitable use of the grid, concerns about the fairness of net metering have been raised, not only in Michigan, but in other states, and have prompted regulatory activity and reports. David LaRoy, a private citizen and DG Workgroup participant, provided an extensive list of such reports in his comments on the draft concept tariff and made a presentation to the workgroup.<sup>9</sup> Information describing some of the DG regulatory activity in other states is provided in **Appendix F**.

Because the cash-out provisions of modified net metering compensate customers at less than the full retail rate, modified net metering recovers a greater level of revenues for the utility. However, it is still a net energy metering method, and thus has the same defects as true net metering, such as incorrect price signals and its lack of cost of service basis. Modified net metering can be thought of as a midway point between true net metering and the Inflow/Outflow billing mechanism.

The lack of price transparency of the NEM billing method is directly related to the fact that costs under NEM are assessed by billing determinants that do not accurately reflect a customer's actual level of grid use. If cost recovery is modified by the addition of a fixed grid-charge (that is invariant with a customer's actual grid use), and if that charge recovers a significant level of the total cost-of-service, then such rate design will only compound the lack of price transparency inherent in NEM. Significantly, the lack of segregated inflow and outflow data from NEM customers not only precludes an accurate determination of the COS allocators in a COSS, but also an accurate determination of the level of costs to be recovered by a potential fixed NEM grid-charge itself.

Thus, despite the fact that it is technically possible to create a NEM rate design that adds a fixed charge to all such DG customers, this approach has difficulty satisfying the requirement that the rates created under the billing method will assess customers for their "fair and equitable use of the grid" as required by Act 341.

In contrast, Staff posits that its Inflow/Outflow methodology is the optimal DG billing method. Its ability to set COS based rates, and its inherent price transparency sets the

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<sup>9</sup> See David LaRoy presentation and comments at [http://www.michigan.gov/mpsc/0,4639,7-159-80741\\_80743-406256--,00.html](http://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406256--,00.html)

framework for the “utility of the future” and the associated new interaction between the utility and customer. It is also the key to customer participation in future utility load-control, demand-response, and energy waste-reduction programs.

### **VIII. Metering and Billing for an Inflow/Outflow Billing Mechanism - Exclusions for Small Utilities**

Under an Inflow/Outflow billing mechanism, metering data must be collected for the inflows and outflows. As discussed elsewhere in this report, inflow is the electricity delivered by the utility to the customer and outflow is the electricity generated by the customer’s project that is not used on-site. The additional cost, resources, and increased complexity of adding a second meter to measure the customer’s generation is not required under the Inflow/Outflow billing mechanism. The tariff proposal is appropriate for rate schedules with flat rates for power supply and distribution, time-based rates and demand rates. The customer is billed for inflow quantities according to their rate schedule. Outflow energy quantities receive a credit.

Both DTE Electric and Consumers Energy have nearly completed deployment of AMI meters for the residential and small commercial customer classes. These meters are fully capable of measuring and recording time-based, hourly inflows and outflows and obtaining the necessary billing determinants for all residential and small commercial rate schedules. A “meter configuration” is created for each specific set of billing determinants needed to bill customers under a particular rate schedule. For DG customers, meter configurations must be established to collect the billing determinants related to the customer’s inflow and outflow.

Alpena, Indiana Michigan, Northern States Power (Xcel), UMER<sup>10</sup> and UPPCo<sup>11</sup> do not have AMI meters deployed. Moving beyond basic net metering to an Inflow/Outflow billing mechanism may not be possible with the current meters and billing systems in place to accommodate true net metering. These utilities should determine the costs and benefits to install the appropriate meters (capable of measuring and recording

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<sup>10</sup> Wisconsin Electric is intentionally omitted due to having only one large, industrial customer and will no longer serve Michigan customers after 2019.

<sup>11</sup> UPPCo’s Category 1 (20 kW and under) net metering program became full and was closed to new customers in July 2016.

bidirectional power flows) for DG customers and provide such information in their next general rate cases.

However, installing AMI meters for a subset of customers may be too costly and difficult to manage with the utility's billing system. Eventually, these utilities may decide to install AMI meters for all residential customers. At the end of 2016, these five utilities reported a total of 238 customers participating in the net metering program.

For those utilities (among the five small utilities) that do not have the ability to cost effectively meter and bill based on Inflow/Outflow billing mechanism, Staff recommends a monthly net billing approach that uses the Outflow Compensation Mechanism (emanating from the upcoming contested proceeding recommended by Staff) to calculate net excess generation credits.

## **IX. Conclusion**

The form of DG tariff being recommended in this report is called an Inflow/Outflow billing mechanism. It is this conceptual framework that is recommended to be submitted by regulated utilities (in any general rate cases filed after June 1, 2018), to implement cost-of-service based rates for DG customers pursuant to Act 341.

For the initial implementation of the new Inflow/Outflow billing mechanism, Staff is recommending that DG customers not be segregated into a separate subclass for cost-of-service study purposes. Thus, implementation of the Inflow/Outflow billing mechanism, will be made using the DG customer's underlying retail rate schedule (including both commodity and demand charges, if applicable). Under this approach, DG customers will pay for their fair use of the distribution grid according to cost of service-based rates.

The new Inflow/Outflow billing mechanism is proposed to be applicable to all distributed generation projects (new projects and those which have been participating for 10 years or more) within the legally defined system capacity cap (i.e. 150 kW, unless the generator is a methane digester, where the system capacity cap is less than or equal to 550 kW) and will replace both the former *true* NEM and *modified* NEM billing methods which were originally authorized by Act 295 of 2008, and which were

continued on an interim basis until a new cost-based “tariff” is approved by the Commission. Consequently, the threshold (of 20 kW) delineating between true NEM and modified NEM would no longer have relevance as all new DG program customers (i.e., customers entering the DG program after the new cost-based tariff is adopted, or existing DG program customers who transition to the cost-based tariff after 10 years under the previous program) would be under the same Inflow/Outflow billing mechanism. It should be noted that the 20kW threshold delineating between the in-state peak-load participation caps defined by Act 342 Sec. 173 (3) remain intact.<sup>12</sup>

In addition, since standby charges under Section 7(i) of Act 342 are an integral part of the modified NEM billing method, and because under Staff’s proposal, no new DG customers would take service under such billing method, no statutory requirement exists regarding the imposition of standby charges to customers taking service under the Inflow/Outflow billing method. Fortunately, the Inflow/Outflow “tariff” meets the fair and equitable requirements of Act 341, recovering the full COS, therefore such charges would be unnecessary.

The new cost-based tariff recommended in this report is in the form of a conceptual framework (i.e. the Inflow/Outflow billing mechanism), as the actual retail rates for each regulated utility will be determined in electric utility rate cases filed after June 1, 2018 (in accordance with Act 341).

The recommended billing framework would only be applicable to new DG customers who enroll in the DG program on and after the effective date of the new cost-based tariff. It would also be applicable to existing NEM customers that have participated in the NEM program longer than 10 years.

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<sup>12</sup> Under PA 342, there is an overall DG program participation cap of 1% of an electric utility’s or alternative electric supplier’s average in-state peak load for the preceding 5 calendar years. This 1% cap is allocated as follows:

- (a) No more than 0.5% for customers with an eligible electric generator capable of generating 20 kilowatts or less.
- (b) No more than 0.25% for customers with an eligible electric generator capable of generating more than 20 kilowatts but not more than 150 kilowatts.
- (c) No more than 0.25% for customers with a methane digester capable of generating more than 150 kilowatts.



On this matter, it is recommended that the Commission clarify that enrollment in the existing NEM program closes upon the effective date of the new DG tariff, and that enrollment means the filing of an application to participate in the net metering program and/or interconnect under the existing NEM program. It is recommended that any existing NEM customer have the option to take service under the new program.

It should be noted that the new Inflow/Outflow billing mechanism is not a replacement for the entire DG “program” detailed in Act 342, but only a replacement for the NEM billing methods contained within that program (e.g. true NEM and modified NEM). The balance of the DG program as authorized by Act 342 remains intact, e.g. enrollment capacity caps, interconnection requirements, enrollment qualifications, etc..

In summary, three key recommendations follow from the Staff’s study:

(1) In any general rate case filed after June 1, 2018, utilities should be instructed to file the attached concept tariff-rider, which includes an Inflow/Outflow pricing mechanism as a foundational framework. The utilities may file additional proposals if desired. Any existing NEM tariff-riders would be amended to indicate that the NEM program is closed to new DG customers upon the effective date of the new tariff.

(2) Upon approval of the Inflow/Outflow concept tariff (on or before April 20, 2018), a new contested proceeding should be established by the Commission to set a uniform *outflow compensation method* for all regulated utilities.

(3) If the Commission adopts the Inflow/Outflow concept tariff as recommended by Staff, all rate regulated utilities should be ordered to file a report, within 60 days, describing their ability to meter and bill according to the Inflow/Outflow mechanism, and incorporate time-based rates for both power inflows and power outflows. Utilities should provide an estimate of the cost to modify billing infrastructure, if necessary, to accommodate the new tariff.

Staff’s recommendations satisfy all requirements set forth by Act 341 regarding the new cost-based tariff for the DG program.

The efforts of DTE Electric and Consumers Energy to provide cost of service models and data contributed greatly to our understanding of distributed generation customer cost of

service and are appreciated. The DG Workgroup process was greatly enhanced by the contributions of the participants. Many traveled significant distances to attend the meetings in person while others used the webinar services to participate remotely.

Staff thanks all DG Workgroup participants and acknowledges the effort of those who prepared studies, analyses and presentations.

- Douglas Jester, 5 Lakes Energy
- Rob Rafson, Chart House Energy
- Chuck Hookam, Consumers Energy
- Brad Klein, Environmental Law and Policy Center
- Alison Williams, Edison Electric Institute
- Katie Hsia-Kiung, Enphase Energy
- Alain Godeau
- David LaRoy
- Jackson Koeppel, Mark Templeton, Robert Weinstock, Rebecca Boyd, Leah Garner, Jamie Lee, Soulardarity/Abrams Environmental Law Clinic
- Andy Haun, Schneider Electric
- Tom Beach, Vote Solar/Crossborder Energy

## **Appendix A: MPSC Staff**

### **Proposed Distributed Generation Program Concept Tariff**

The combination of the customer's retail rate schedule and this conceptual rider (Rider) constitutes the cost-based distributed generation (DG) tariff pursuant to PA Act 341 of 2016 Section (6) (a) (14). The customer is billed according to their retail rate schedule for all Inflow and receives a credit in dollars, rather than kWh, based on the Outflow Credit provision shown on the Rider.

The credit for outflow during the billing month is applied to the total monthly bill less the monthly customer charge. The customer will always pay the monthly customer charge. Any unused outflow bill credit is added to any unused bill credit from previous months and carried forward to the next month. The utility will not issue a check for unused bill credit unless the customer leaves the DG program.

#### **C11. DISTRIBUTED GENERATION PROGRAM**

- A. The Distributed Generation Program is offered as authorized by 2008 PA 295, as amended, 1939 PA 3, as amended by 2016 PA 341, Section (6) (a) (14), and the Commission in Case No. U-\_\_\_\_\_.
  
- B. Distributed Generation Definitions
  - (1) A Category 1 distributed generation customer has one or more Eligible Electric Generators with an aggregate nameplate capacity of 20 kWac or less that use equipment certified by a nationally recognized testing laboratory to IEEE 1547.1 testing standards and is in compliance with UL 1741 scope 1.1A located on the customer's premises and metered at a single point of contact.
  - (2) A Category 2 distributed generation customer has one or more Eligible Electric Generators with an aggregate nameplate capacity greater than 20 kWac but not more than 150 kWac located on the customer's premises and metered at a single point of contact.
  - (3) A Category 3 distributed generation customer has one or more methane digesters with an aggregate nameplate capacity greater than 150 kWac but not more than 550 kWac located on the customer's premises and metered at a single point of contact.
  - (4) Eligible Electric Generator – a renewable energy system or a methane digester with a generation capacity limited to no more than 100% of the customer's electricity consumption for the previous 12 months and does not

exceed the following:

- a. For a renewable energy system, 150 kWac of aggregate generation at a single site
  - b. For a methane digester, 550 kWac of aggregate generation at a single site
- (5) Inflow – the metered inflow delivered by the Company to the customer during the billing month or time-based pricing period.
- (6) Outflow – the metered quantity of the customer’s generation not used on site and exported to the utility during the billing month or time-based pricing period.
- (7) Renewable Energy Resource – a resource that naturally replenishes over a human, not a geological, timeframe and that is ultimately derived from solar power, water power or wind power. Renewable energy resource does not include petroleum, nuclear, natural gas, or coal. A renewable energy resource comes from the sun or from thermal inertia of the earth and minimizes the output of toxic material in the conversion of the energy and includes, but is not limited to, all of the following:
- (i) Biomass
  - (ii) Solar and solar thermal energy
  - (iii) Wind energy
  - (iv) Kinetic energy of moving water, including the following:
    - (a) waves, tides or currents
    - (b) water released through a dam
  - (v) Geothermal energy
  - (vi) Thermal energy produced from a geothermal heat pump
  - (vii) Any of the following cleaner energy resources:
    - (a) Municipal solid waste, including the biogenic and anthropogenic fractions
    - (b) Landfill gas produced by municipal solid waste
    - (c) Fuel that has been manufactured in whole or significant part from waste, including, but not limited to, municipal solid waste. Fuel that meets the requirements of this subparagraph includes, but is not limited to, material that is listed under 40 CFR 241.3(b) or 241.4(a) or for which a nonwaste determination is made by the United States Environmental Protection Agency pursuant to 40 CFR 241.3(c). Pet coke, hazardous waste, coal waste, or scrap tires are not fuel that meets the requirements of this subparagraph.

#### C. Distributed Generation Program Availability

The Distributed Generation Program is available for eligible Distributed

Generation customers beginning with the first day of the \_\_\_\_\_ 2019 Bill Month.

A customer participating in a net metering program approved by the Commission before *(date of the rate case order approving this tariff)* shall have the option to take service under this tariff at the time service under the terms and conditions of the previous net metering program terminates in accordance with MCL 463.0183(1).

The Distributed Generation Program is voluntary and available on a first come, first served basis for new customer participants or existing customer participants increasing their aggregate generation. The combined legacy net metering and DG program size is equal to 1.0% of the Company's average in-state peak load for Full-Service customers during the previous 5 calendar years. Within the Program capacity, 0.5% is reserved for Category 1 Distributed Generation customers, 0.25% is reserved for Category 2 Distributed Generation customers and 0.25% is reserved for Category 3 Distributed Generation customers. The Company shall notify the Commission upon the Program reaching capacity in any Category.

D. Customer Eligibility

In order to be eligible to participate in the Distributed Generation Program, customers must generate a portion or all of their own retail electricity requirements with an Eligible Electric Generator which utilizes a Renewable Energy Resource, as defined in Rule C11.B, Distributed Generation Definitions.

A customer's eligibility to participate in the Distributed Generation Program is conditioned on the full satisfaction of any payment term or condition imposed on the customer by pre-existing contracts or tariffs with the Company, including those imposed by participation in the Distributed Generation Program, or those required by the interconnection of the customer's Eligible Electric Generator to the Company's distribution system.

E. Customer Billing on Inflow – Category 1, 2 and 3 Customers

(1) Full Service Customers

The customer will be billed according to their retail rate schedule, plus surcharges, and Power Supply Cost Recovery (PSCR) Factor on metered Inflow for the billing period or time-based pricing period.

(2) Retail Open Access Customers

The customer will be billed as stated on the customer's Retail Open Access Rate Schedule on metered Inflow for the billing period or time-

based pricing period.

F. Customer Billing – Outflow Credit

The customer will be credited on Outflow for the billing period or time-based pricing period. The credit shall be applied to the current billing month and shall be used to offset total utility charges (exclusive of the monthly customer charge) on that bill. Any excess credit not used will be carried forward to subsequent billing periods. Unused Outflow Credit from previous months will be applied to the current billing month, if applicable. Outflow Credit is non-transferrable.

(1) Full Service Customers

The Outflow compensation methodology will be established by the Commission in a contested case proceeding.

(2) Retail Open Access Customers

The Outflow Credit will be determined by the Retail Service Supplier.

G. Application for Service

In order to participate in the Distributed Generation Program, a customer shall submit completed Interconnection and Distributed Generation Program Applications, including the application fee of \$50 to the Company.

The Distributed Generation Program application fee is waived if the customer is transitioning from the Net Metering Program.

If a customer does not act or correspond on an application for over 6 months, when some action is required by the customer, the application may be voided by the Company.

H. Generator Requirements

The Eligible Electric Generator(s) must be located on the customer's premises, serving only the customer's premises and must be intended primarily to offset a portion or all of the customer's requirement for electricity.

The customer's requirement for electricity shall be determined by one of the

following methods:

- (1) The customer's annual energy usage, measured in kWh, during the previous 12-month period
- (2) In instances where complete and correct data is not available or where the customer is making changes on-site that will affect total usage, the Company and the customer shall mutually agree on a method to determine the customer's annual electric requirement

The aggregate capacity of Eligible Electric Generators shall be determined by the aggregate projected annual kWh output of the generator(s).

The customer is required to provide the Company with a capacity rating in kW of the generating unit and a projected monthly and annual Kilowatt-hour output of the generating unit when completing the Company's Distributed Generation Program Application.

The customer need not be the owner or operator of the eligible generation equipment, but is ultimately responsible for ensuring compliance with all technical, engineering and operational requirements suitable for the Company's distribution system.

#### I. Generator Interconnection Requirements

The requirements for interconnecting a generator with the Company's facilities are contained in Rule B8., Electric Interconnection and Distributed Generation Standards, the Michigan Electric Utility Generator Interconnection Requirements and the Company's Generator Interconnection Supplement to Michigan Electric Utility Generator Interconnection Requirements. All such interconnection requirements must be met prior to the effective date of a customer's participation in the Distributed Generation Program. The customer must sign an Interconnection and Operating Agreement with the Company and fulfill all requirements as specified in the Agreement. The customer shall pay actual interconnection costs associated with participating in the Distributed Generation Program, subject to limits established by the Michigan Public Service Commission.

#### J. Metering Requirements

Metering requirements shall be specified by the Company, as detailed below. All metering must be capable of recording inflow and outflow and all parameters metered on the customer's otherwise applicable retail rate schedule, for both Full Service and Retail Open Access customers.

K. Distribution Line Extension and/or Extraordinary Facilities

The Company reserves the right to make special contractual arrangements with Distributed Generation Program customers whose utility service requires investment in electric facilities, as authorized by the Company's Rule C1.4, Extraordinary Facility Requirements and Charges, Rule C1.6, General Provisions of Service, and Rule C6., Distribution Systems, Line Extensions and Service Connections, as set out in the Company's Electric Rate Book. The Company further reserves the right to condition a customer's participation in the Distributed Generation Program on a satisfactory completion of any such contractual requirements.

L. Customer Termination from the Distributed Generation Program

A participating customer may terminate participation in the Company's Distributed Generation Program at any time for any reason on sixty days' notice. In the event that a customer who terminates participation in the Distributed Generation Program wishes to re-enroll, that customer must reapply as a new program participant, subject to program size limitations, application queue and application fees.

The Company may terminate a customer from the Distributed Generation Program if the customer fails to maintain the eligibility requirements, fails to comply with the terms of the operating agreement, or if the customer's facilities are determined not to be in compliance with technical, engineering, or operational requirements suitable for the Company's distribution system. The Company will provide sixty days' notice to the customer prior to termination from the Distributed Generation Program, except in situations the Company deems dangerous or hazardous. Such notice will include the reason(s) for termination.

Upon customer termination from the Distributed Generation Program, any existing credit on the customer's account will either be applied to the customer's final bill or refunded to the customer. The Company will refund to the customer any remaining credit in excess of the final bill amount. Distributed Generation Program credit is non-transferrable.

M. Company Termination of the Distributed Generation Program

Company termination of the Distributed Generation Program may occur upon receipt of Commission approval.

Upon Company termination of the Distributed Generation Program, any existing credit on the customer's account will either be applied to the customer's final bill or refunded to the customer. The Company will refund to the customer any remaining credit in excess of the final bill amount. Distributed Generation Program credit is non-transferrable.



N. Distributed Generation Program Status and Evaluation Reports

The Company will submit an annual status report to the Commission Staff by March 31 of each year including Distributed Generation Program data for the previous 12 months, ending December 31. The Company's status report shall maintain customer confidentiality.

O. Renewable Energy Credits

Renewable Energy Credits (RECs) are owned by the customer.

The Company may purchase Renewable Energy Credits from participating Distributed Generation Program customers who are willing to sell RECs generated if the customer has a generator meter in place to accurately measure and verify generator output. REC certification costs are the responsibility of the customer.

The Company will enter into a separate agreement with the customer for the purchase of any RECs.

## **Appendix B**

### **Comments Received**

Comments Received on the Draft Report (January 2018)

Detailed Comments

[http://www.michigan.gov/documents/mpsc/Detailed\\_Responses\\_612317\\_7.pdf](http://www.michigan.gov/documents/mpsc/Detailed_Responses_612317_7.pdf)

General Comments

[http://www.michigan.gov/documents/mpsc/General\\_Responses\\_612319\\_7.pdf](http://www.michigan.gov/documents/mpsc/General_Responses_612319_7.pdf)

Comments Received During the Draft Tariff Comment Period (November 2017)

[http://www.michigan.gov/mpsc/0,4639,7-159-80741\\_80743-406256--,00.html](http://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406256--,00.html)

**A Reasoned Analysis**  
**For a New Distributed-Generation Paradigm**  
***The Inflow & Outflow Mechanism***  
**A Cost of Service Based Approach**

**By Robert G. Ozar P.E.**

**August 24, 2016**

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## Abstract

Net Energy Metering (NEM) is a balancing method that allows electric utility customers the ability to generate on-site intermittent renewable resources, like rooftop solar PV, that deviate significantly from the customer's actual electric load: but receive credit on their utility bills as if the grid was a giant battery, storing and releasing net excess generation as needed. NEM is intrinsically a subsidized balancing service, and customers whose generation output is nominally equal to the customer's annual electric load can obtain essentially free grid-services. In contrast, the Buy all – Sell all method that is often considered as a replacement, errors in the opposite direction, overcharging customers for their actual grid usage and over-crediting the same customer for the portion of generation that is injected into the utility grid. The *Inflow & Outflow* mechanism is the only regulatory alternative to Net Energy Metering that is a true cost-of-service based approach. The *Inflow & Outflow* mechanism is uniquely simple, being based upon actual metered power-inflows from the grid, and actual metered outflows to the grid. The *Inflow & Outflow* mechanism requires a bi-directional meter (smart meter). The method results in a rate structure that can yield accurate price signals inducing optimal operation, especially when the distributed generation is combined with battery storage, or advanced inverters allowing for demand response services. Finally, pursuant to the *Inflow & Outflow* mechanism, traditional rate design and cost allocation methods, procedures, and principles, can be used to establish rates.

The principles and analysis of this paper were first presented to the Michigan Public Service Commission in February, 2016, and to the Michigan Public Service Commission Stand-by Working Group, in June, 2016.

## The Interface of Distributed Generation Mechanisms and Renewable Energy: Introduction

It is well known that the market share for customer sited solar photovoltaic (PV) has increased dramatically over the past five years. Rapidly declining costs of panels combined with federal tax credits have resulted in a mushrooming of installations on rooftops across America. However, behind the scenes, the almost universal availability of net-energy-metering (NEM) may be nearly as significant to the growth in customer sited distributed generation (DG).

NEM's influence on the rate of installations should not be underestimated. The reason is simple: due to declining costs, the economics of customer sited-solar steadily improved, but absent NEM, rarely provided a full economic-payback over the expected useful-life of the systems.

That solar PV's growth in market share was dependent on utility rate-subsidies was known from its inception. For that reason, many states, Michigan included, set a cap on the aggregate level of net-metering, typically 1% of a utility's retail load. NEM worked remarkably well, and as intended, functioned as a market accelerant, jump-starting the struggling solar PV market.

As installation costs declined, the regulatory mechanism created a positive net-present-value (NPV) for many customers. The improved economics are a direct result of the kWh netting process inherent to NEM. This netting process also facilitates a nearly ideal customer experience, since the local utility takes responsibility for balancing the generation output (which is variable and intermittent) with the customer's load profile.

As the level of NEM approaches (and for some utilities, exceeds the 1% cap), a re-examination of the mechanism is in order.

Re-examination must begin by exposing the regulatory limitations that were germane to the analog-metering world of the early solar-PV industry. The inability to independently measure a distributed generation (DG) customer's power flows to, and from the grid, gave regulators little choice but to capitalize on a technological quirk of old fashioned analog-meters – they could run backward. This ability is the essence of the NEM mechanism. Utilities were thus able to provide a monthly bill that reflected the net difference between a customer's base usage, and the monthly generation output. Unfortunately, it also provided regulators little flexibility, in the way of utility rate-design, to recover the cost of providing NEM services. Fortuitously that defect worked in NEM's favor.

In contrast, modern digital meters, i.e. “smart meters”, are unconstrained, being able to **independently and instantaneously meter power-flows in both directions**. For this reason, the focus of our reexamination of NEM must be directed toward understanding the actual power flows created by DG customers, and how that knowledge can be used to design a true cost-of-service rate structure.

The common characteristic of all DG customers is that their generation system is interconnected and operating “in parallel” with the utility grid. However, the power flows to and from the utility grid are not independent variables, they are a by-product of something more essential and basic to the operation of a DG system. Inquiry into this interplay is the thrust of modeling and analysis behind this paper.

We define the energy output of a DG system that is directly consumed by the customer, as “onsite usage”. Onsite-usage constitutes a direct and physical load-loss to the utility. The level of onsite usage varies on an hourly basis throughout the year, especially with variable and intermittent renewable resources, but modeling can extract the more obscure mathematical relationships needed to make progress on DG program design.

**Because onsite-usage can be quantified by reference to smart-metered power flows, it is the key to unlocking past barriers to implementation of cost-of-service based DG tariffs.**

As we will see, the netting process inherent to NEM has the practical effect of expanding onsite-usage to include the entire solar output of a customer’s DG system, with a commensurate increase in lost utility-revenue. This is a critically important attribute of NEM.

Unlike small power producer programs, such as under the Public Utility Policies Act of 1978, Pub L No. 95-617, 92 Stat 3117 (PURPA), NEM programs generally limit DG capacity to the customer’s annual electric load. Such regulatory limits reflect the essential purpose of DG programs – to allow customers to self-generate their electric requirements. In light of this purpose, the sale of excess power to the utility is never an end-goal of DG operation, but rather a reflection of sub-optimal system operation.

Under NEM, a system sized to meet the nominal annual customer-load can, in theory, result in a total load (and revenue) loss to the utility. In such a case, the revenue impact to the utility is nearly identical to that of a customer that is physically disconnected from the grid, and for this reason it can be said that NEM can create a “virtual” grid defection.

This might seem like strong language, but the lost-sales impact of NEM goes well beyond the commonly suggested issue of non-participating customer subsidies for uncompensated grid-services.

NEM hits at the core of an investor owned utility’s long-term financial objectives, in particular the objective to grow rate-base through system expansion or replacement. It is this characteristic that has seized the attention of utilities across the country.

State regulatory and legislative bodies are responding to utilities’ outcry by considering a patchwork of disparate replacement programs. Unfortunately, it is clear that an ad hoc regulatory-approach is developing, rather than coalescence toward a new dominant regulatory paradigm. Various forms and combinations of modified NEM, minimum bills, demand charges, and “buy-all sell-all” (BASA) mechanisms are being proposed to restore utility revenues.

## **The Inflow & Outflow Mechanism: Analysis**

As a regulator having a core stake in the controversy, the author asked a fundamental question: would it be possible to develop a new regulatory framework that is cost-of-service based, simple, and can be applied universally?

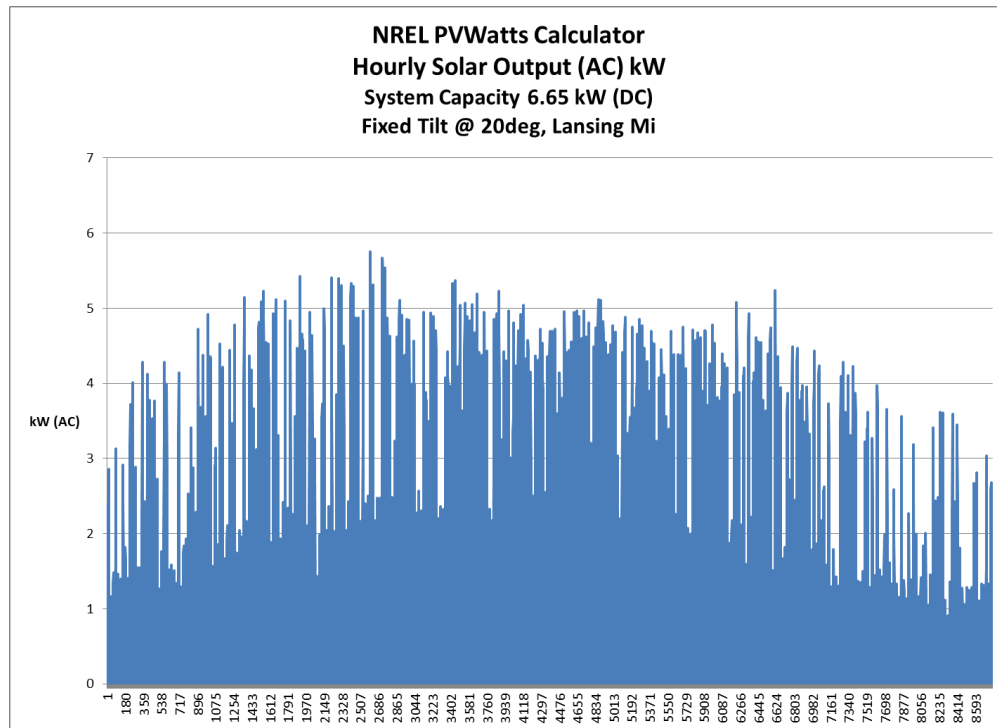
This core question was answered through modelling and analysis, combined with extensive real-world experience developing regulatory mechanisms. **The resulting thesis of this paper, and the opinion of the author, is that the only regulatory mechanism that has all the necessary attributes to qualify as a new paradigm for electric utility DG programs is the Inflow-and-Outflow (I&O) mechanism.** The basis for this mechanism will be reviewed thoroughly in the body of this paper.

Regulators have learned that a little bit of modeling can go a long way toward suggesting an optimal regulatory framework, and distributed generation programs are no exception. A proper characterization of grid usage requires an 8,760 hour model.

Without having to reinvent the wheel, analysis incorporated hourly solar output based on the National Renewable Energy Lab's (NREL's) PVWatts Calculator [for Lansing, Michigan]; and the residential hourly load distribution was derived from the DOE/NREL System advisor Model (SAM) [for Lansing Capital City Airport (TMY3)]. Hourly load data was adjusted so that the cumulative monthly usage matched the historical-average residential consumption for Consumers Energy (CE), of 8,307 kWh, during calendar year 2010.

Chart (1) shows an example of the hourly data for a solar PV system of 6.65 kWh (DC). The aggregate annual generation output of this system size is equivalent to the average-annual residential consumption of 8,307 kWh. Such a NEM customer would effectively have a net zero annual electric bill (excepting the CE access charge of \$7.00 per month).

#### **Chart 1**



The hourly consumption and solar output data generated by the SAM and PV Watts models, was uploaded into an Excel spreadsheet, allowing for extensive sensitivity analysis both upstream and downstream of the utility’s billing meter, e.g. changes in installed solar PV capacity, power inflows, power outflows, onsite usage, netting, and battery-storage impacts. Rate impacts incorporated CE’s most recently approved residential standard and dynamic pricing tariffs.

Although the Excel model was relatively simple, the results proved outstanding, clearly revealing fundamental principles useful to regulatory program design. So let’s begin by looking at the development of the model, and then follow up with the interpretation of the results, economic analysis, and future DG program design.

The two fundamental parameters representing grid usage are power-inflows and power-outflows. In the context of DG program design, and operation, both terms are defined from the point of reference of the customer. INFLOW is power taken off the grid; OUTFLOW is power put onto the grid. Inflow and outflow are exceptionally useful in quantifying grid usage and understanding grid impacts, thus these parameters are the focus of DG modeling efforts.

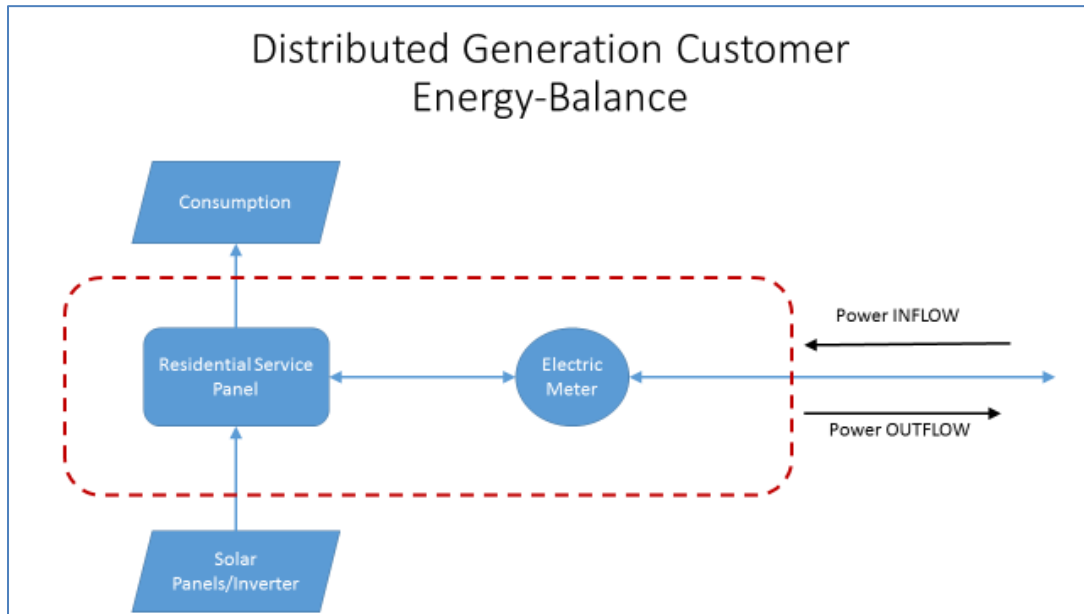
Importantly, inflow and outflow must be derived since the model input consists of hourly solar generation and consumption, not power flows. The derivation of the mathematical relationships between generation and consumption, and power inflows and outflows, starts with an energy balance:

$$\text{[Energy In = Energy Out]} \quad \text{Equation (1)}$$



The energy balance is written to encompass the customer's service panel and the utility meter, as in Chart (2) below.

**Chart 2**



Inserting all energy flows intersecting the energy balance boundary [dashed line in Chart (2)] into Equation (1), yields an exact relationship between the model's key input variables, generation and consumption, and the desired grid parameters, inflow and outflow; i.e.

$$\text{[Generation + Inflow = Consumption + Outflow]} \quad \text{Equation (2)}$$

Or alternately stated;

$$\text{[Inflow – Outflow] = [Consumption – Generation]} \quad \text{Equation (3)}$$

Since the model input consists of hourly values for consumption and generation, the net quantity, [Inflow – Outflow], can be derived on an hourly basis via Equation (3), but independent values for inflow and outflow during each hour are indeterminate. This is where modeling diverges slightly from the actual operations.

Strictly speaking, modern digital smart-meters measure hourly inflows and outflows by integrating the instantaneous power flows. Over the course of any particular hour, then, both inflows and outflows may take place, and be measured.

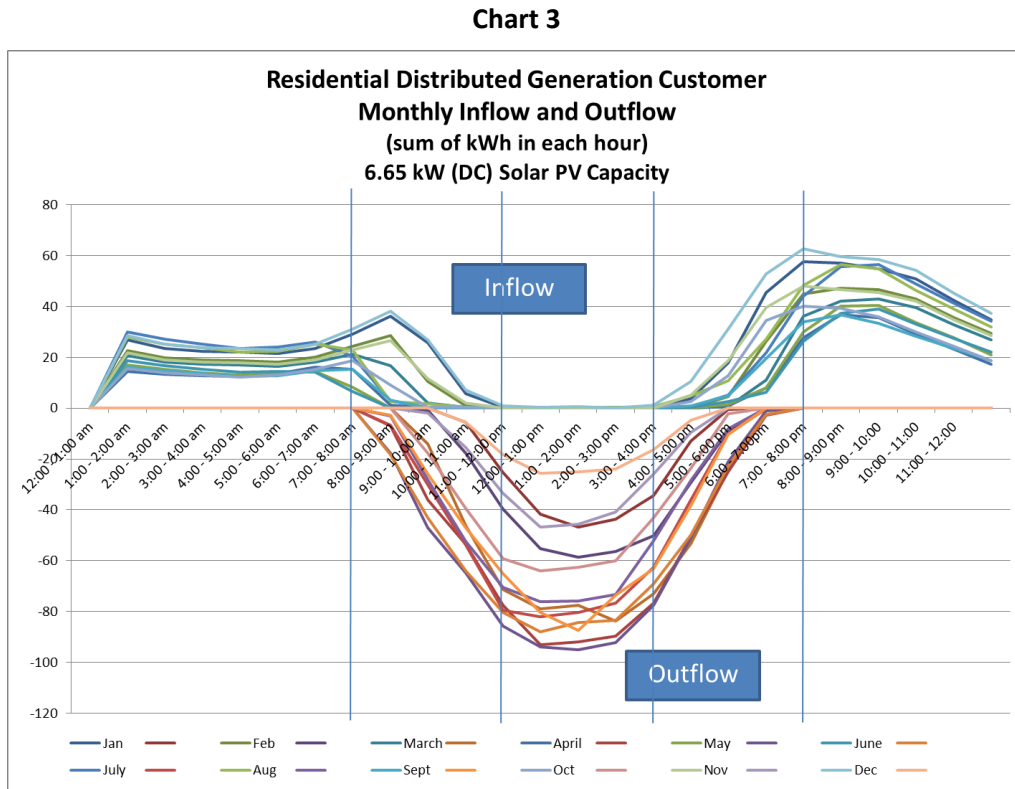
At this point a simplifying assumption must be made for modeling purposes. Since consumption and generation data-output by the SAM and Solar PV models are limited to hourly values, the energy balance is limited in its ability to derive independent [integrated] inflows and outflows during each hour.

A simplifying assumption may be made that a net positive value of [Consumption – Generation] over the course of an hour represents a practical estimate of the integrated hourly inflow for that period. In such

cases, the outflow for that hour is defined as zero. Conversely, a net negative value of [Consumption – Generation] represents an hourly outflow (of excess generation).

In this manner, a stream of 8760 (hourly) inflows and outflows are developed from consumption and generation data. Each hour has an inflow or outflow, but not both.

Chart (3) below, reveals the trend in inflow and outflow values over the course of a 24 hour period and from month-to-month over the course of a year. Inflows peak in the morning and evening, and outflows peak during the mid-afternoon.



It was previously asserted that onsite-usage is fundamental to analysis of DG operation, and that too can be derived from an energy balance. Rearranging Equation (3) yields two identities:

$$[\text{Generation} - \text{Outflow}] = [\text{Consumption} - \text{Inflow}] \quad (\text{Equation 4})$$

These mathematical identities are recognized as representing the “onsite-usage” portion of the generation output.

The identities provide a means to derive onsite-usage, once hourly inflows and outflows have been estimated. Thus, in any given hour:

$$\text{Onsite usage} = [\text{Generation} - \text{Outflow}] \quad (\text{Equation 5})$$

Or if outflow is equal to zero in such hour:

$$\text{Onsite usage} = [\text{Consumption} - \text{Inflow}] \quad (\text{Equation 6})$$

Although for modeling purposes Equations (1) through (6) are used to calculate hourly values, the reader should note that because these equations flow from an energy balance, they are valid over any timeframe. They can be used on an instantaneous basis, or cumulatively, in any given hour, month or year.

We now have means to calculate the core parameters needed to model any type of regulatory DG mechanism. The next step is to restate Equations (5) and (6) into a form that reflects cause and effect, rather than modeling convenience. In this way, additional insight into onsite-usage can be obtained.

Noting that onsite-usage constitutes generation output (kWh) that is immediately taken up by the customer's electric-load, it is clear that it is an independent variable vis-à-vis the downstream (from the customer's meter) power flows; inflow and outflow. The physical flow of power upstream of the utility billing meter thus suggests that onsite-usage is actually a function of generation and consumption, as opposed to the form of Equations (5) and (6). To be specific, if generation is greater than, or equal to, consumption, then onsite usage is equal to consumption. If generation is less than consumption, then onsite usage is equal to generation. Mathematically these concepts can be stated as follows:

$$\text{If Generation} \geq \text{Consumption: Onsite-usage} = \text{Consumption} \quad (\text{Equation 7})$$

$$\text{If Generation} < \text{Consumption: Onsite usage} = \text{Generation} \quad (\text{Equation 8})$$

Thus, the physical electrical system suggests that Equations (5) and (6) be rearranged to a form in which inflow and outflow are the dependent variables:

$$\text{Inflow} = [\text{Consumption} - \text{Onsite Usage}] \quad (\text{Equation 9})$$

And:

$$\text{Outflow} = [\text{Generation} - \text{Onsite Usage}] \quad (\text{Equation 10})$$

This restatement, yields a profound and nearly intuitive relationships between a customer's effective draw of power from the grid (i.e. inflow or outflow), and the level of generation consumed on-site.

These concepts can be visualized by reference to Charts (3) and (4) below which reveals how onsite-usage modifies the power flows resulting from interconnection of a customer-sited DG system to the utility grid.

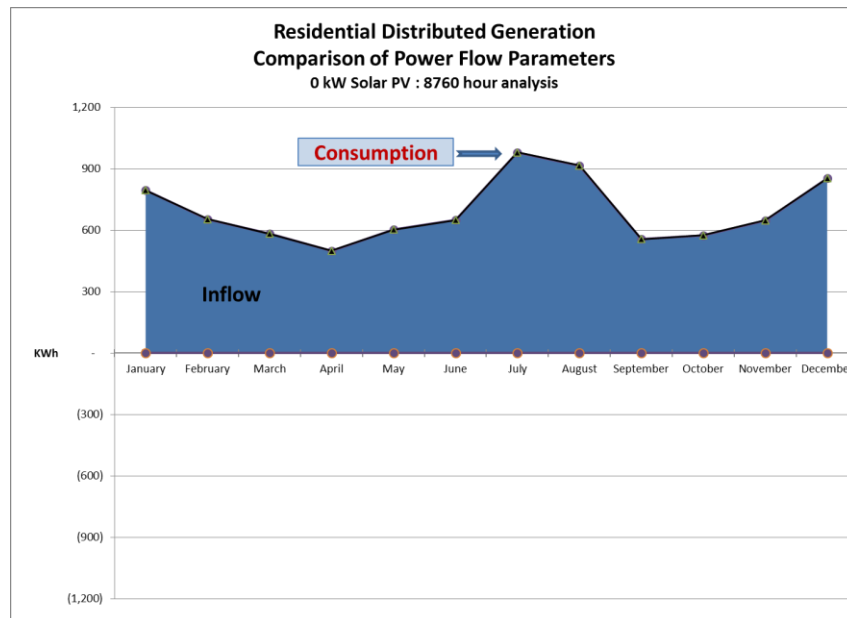
We start by looking at power flows created by a residential customer prior to having deployed a solar PV system. In this case, it is obvious that without generation, both onsite usage and outflow are zero. Absent a generation source, the energy balance, Equation (2), collapses to the simple identity:

**Consumption = Inflow**

**Equation (11)**

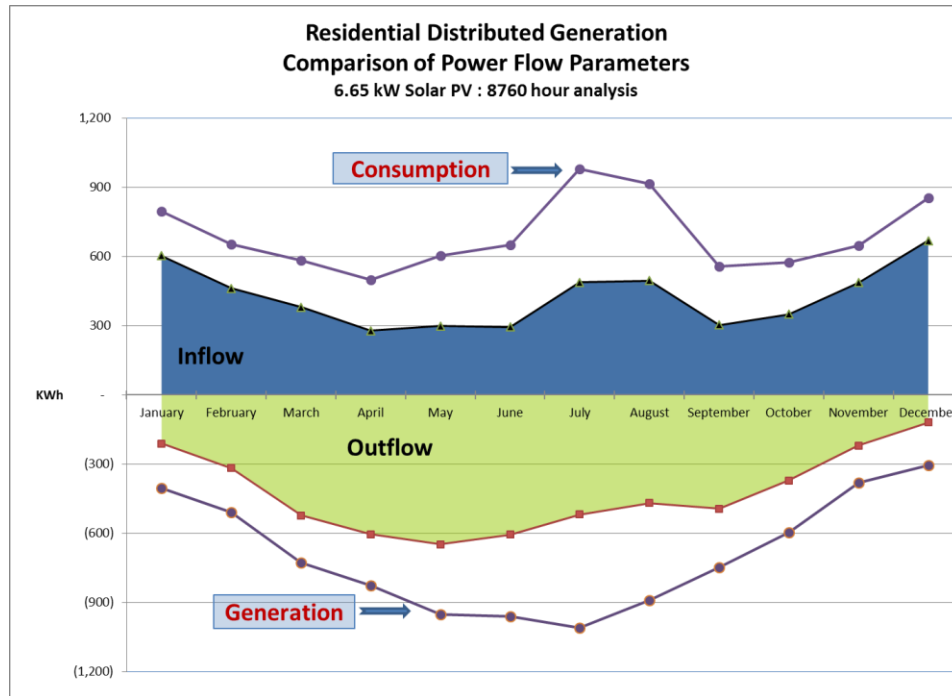
This identity can be seen in Chart (4) below, as the merging of the consumption and inflow curves over the course of the year.

**Chart 4**



Turning to Chart (5) below, we see how power inflows are affected by the addition of a 6.65 kW solar PV system. Cumulative monthly data graphed in Chart (5) represents the four foundational parameters; consumption, generation, inflow and outflow.

Chart 5



Referring to Chart (5), the top and bottom lines represent consumption and generation. The banded blue and green areas represent power inflows and outflows resulting from the consumption and generation profiles. In contrast to Chart (4), notice how the inflow curve is disengaged, and at a lower level from the consumption curve.

Onsite usage is not directly plotted in Chart (5), however, it is clearly evident and consistent with Equation (9), which takes the form:  $\text{Inflow} = [\text{Consumption} - \text{Onsite Usage}]$ . Similarly, Equation (10) states that:  $\text{Outflow} = [\text{Generation} - \text{Onsite Usage}]$ . From these two equations it can be inferred that the two white bands separating consumption from inflow, and generation from outflow, denote the customer's actual onsite-usage.

Chart (5), above, creates a striking visualization of how onsite-usage modifies the power flows between an interconnected DG customer and the grid: first, by reducing the draw of power from the grid; and second, by reducing the level of "excess" generation injected into the grid. Both reductions are equal to the level of onsite-usage.

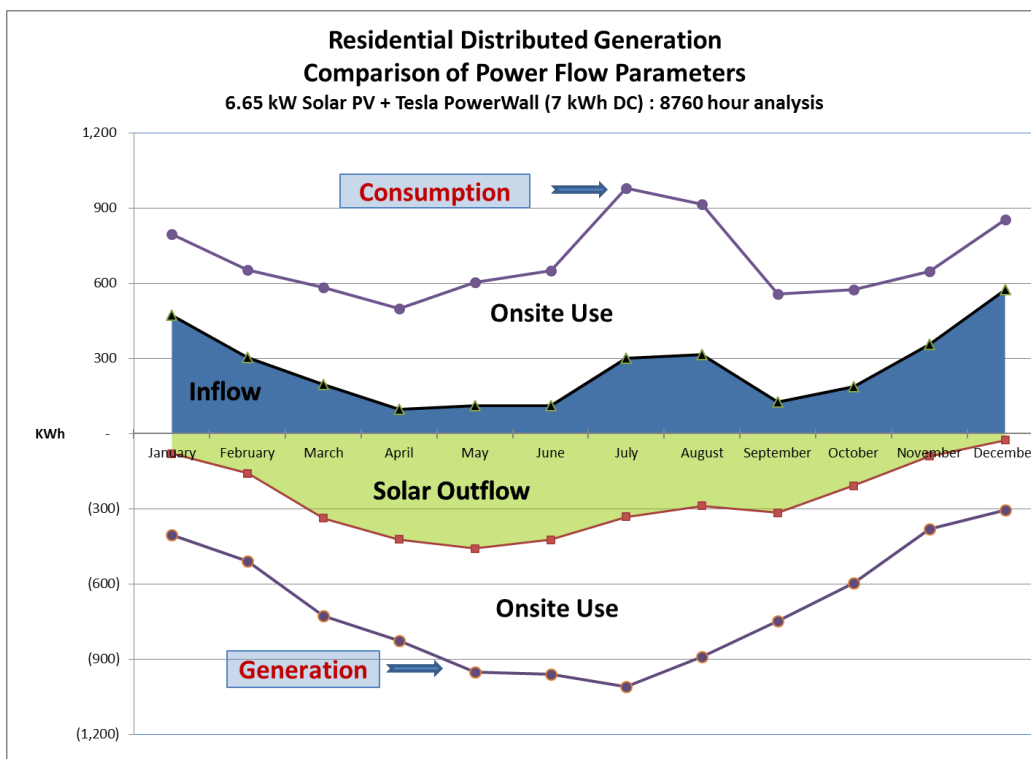
It is logical to conclude that if the level of generation physically used on-site could be increased, then to that extent, more efficient operation of the DG system would be achieved.

Taking this concept to the limit, it can be deduced that **optimal operation of grid-interconnected DG systems occurs when onsite-usage is maximized**. It follows that optimal operation, as thus defined, by

minimizing the purchase of energy from the utility, would as a result, simultaneously minimize “excess” generation (i.e. power outflows). The reduction of retail purchases of energy from the utility, is, after all, the primary reason customers install DG systems. This is consistent with the previous assertion that the purpose of a DG customer program is to allow the self-generation of customer’s electric-load.

A noteworthy example of a change in customer operations, that yields an increased level of onsite-usage, is shown by Chart (6) which adds a 7 kWh Tesla Powerwall to the 6.65 solar PV system represented by Chart (5). The end result is a commensurately increased level of operational efficiency.

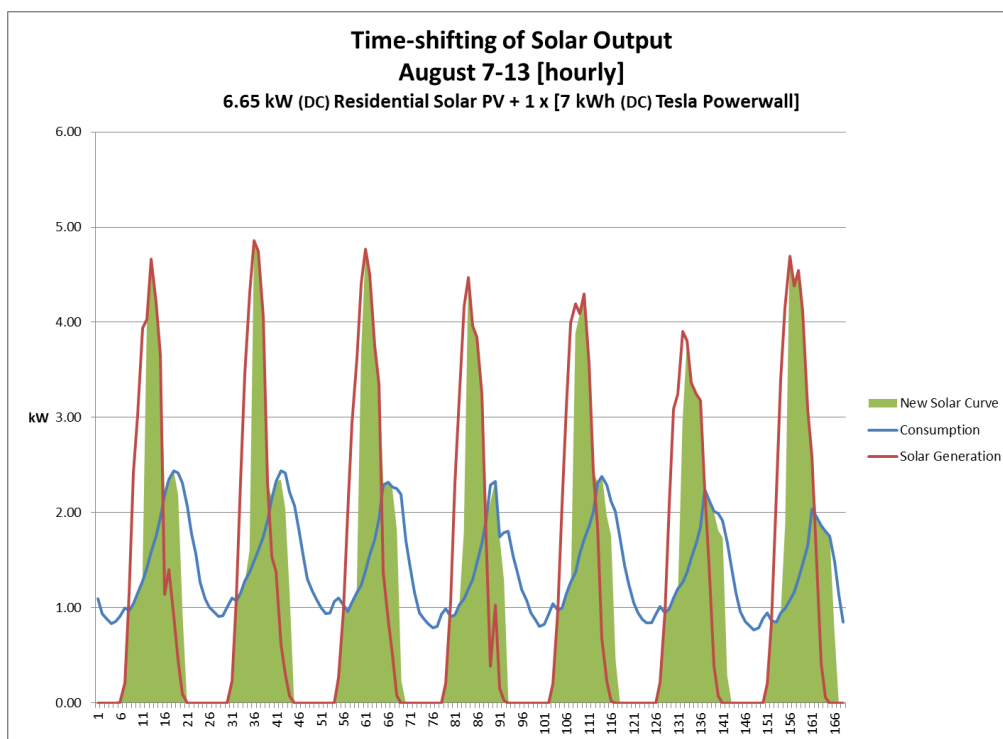
Chart 6



Notice that daily cycling of the battery yields a significant reduction in power inflows vis-à-vis a stand-alone solar PV system as seen in Chart (5). The reduction in power inflows is a direct result of increasing the level of onsite-usage, by charging the battery during periods of excess generation, and discharging during periods of insufficient generation.

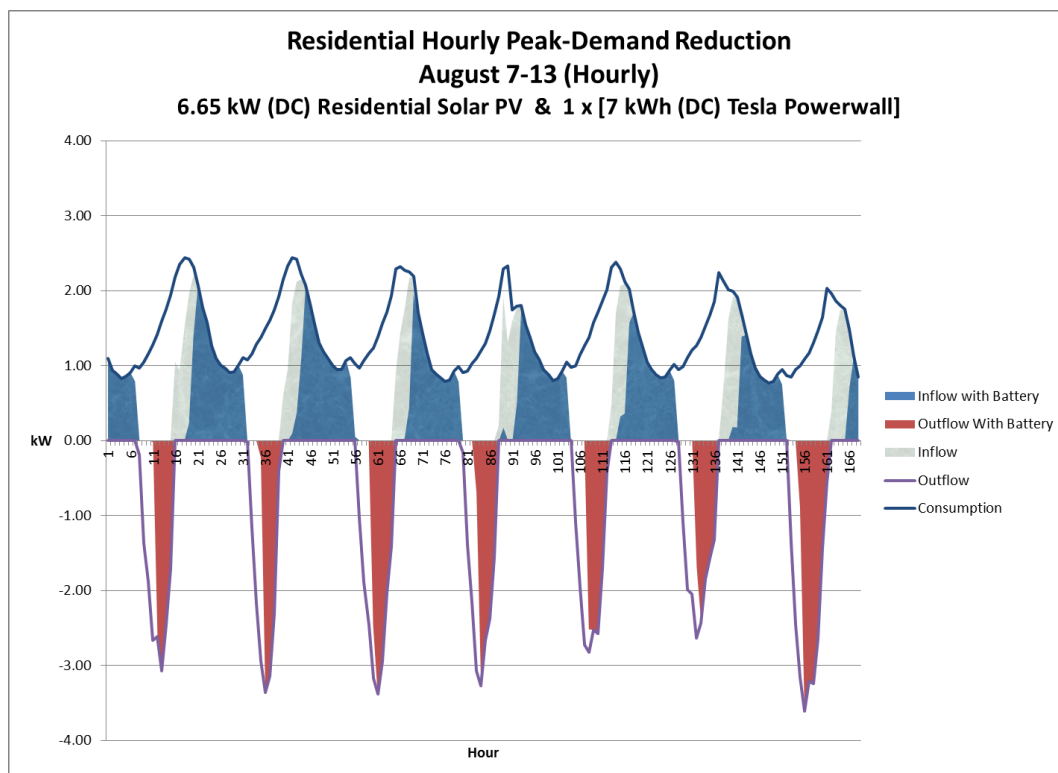
The cause and effect relationship between increased onsite-usage and efficient operation can be seen in more striking detail by graphing the *hourly* power flows of the above residential solar/battery customer, as seen in Chart (7) below. Chart (7) plots consumption and generation on an hourly basis, during the week of August 7-13. The blue line is consumption, the red line is generation. What is of most interest is the “new solar curve” plotted in green.

Chart 7



The new solar curve constitutes a time-shifted generation profile, consisting of hourly solar-output less battery charge, plus battery discharge. Notice that the new solar-output curve begins to follow the consumption curve, especially during the daily peak-demand periods. **The merging of solar/battery output with consumption is a clear indication of enhanced operational efficiency, since it will result in an increased level of onsite usage.** The timing of this occurrence is also a factor leading toward operational efficiency. Chart (7), thus, hints that the draw of power from the grid during the peak-demand period (inflow) should decline in step with the time-shifted generation output, and this can be seen in Chart (8) below, which is a plot of pre and post-battery inflows and outflows.

Chart 8





Notice in Chart (8) the decreased inflows resulting from inclusion of a battery system. The white areas under the consumption curve represents the reduction in inflow stemming from the solar PV system itself. The light blue areas represents further reductions in inflow as a result of the battery storage operations. The relatively small dark-blue areas are the remaining power-inflows resulting from the solar/battery combination. The net difference between the base residential consumption and the remaining hourly inflow is onsite-usage, [as originally seen terms of monthly values in Chart (5) as the white band separating inflow from consumption].

Having now conclusively demonstrated that **the key operational driver toward efficient operations is the level (and timing) of onsite usage**, it behooves both lawmakers and regulators alike to design the regulatory construct for DG programs so that it provides economic benefits to customers who increase their level of onsite usage.

It is entirely rational to use this observation as a test of any proffered DG regulatory mechanism. It can thus be asserted that: **if the economic payback to a customer under a particular regulatory mechanism is indifferent, or nearly indifferent, to the actual level of onsite-usage, then such mechanism is inherently flawed.**

**Because efficient operation tends toward the expansion of onsite usage at the expense of bill credits for excess power**, DG program structure should be designed so that the displacement of utility purchases (via onsite usage) should create the majority of the cash-flow needed to make the investment in customer-sited generation economic over the lifecycle of the system. Bill credits for the “sale” of excess power are merely secondary manifestations of optimal operation. This proposition can also be useful in evaluating the merit of alternative DG mechanisms, such as the Buy all – Sell all (BASA) mechanism. In practice, increasing the level of generation consumed onsite requires active customer involvement.

So, how does a regulatory mechanism promote customer involvement? By providing appropriate economic incentives to DG customers. It can be thus stated unequivocally that **a necessary precondition for achieving appropriate economic incentives is the implementation of a regulatory rate-design that incorporates power-inflows and power-outflows as billing determinants.**

It is highly relevant that cost-of-service ratemaking principles applied to retail DG program design result in the greatest potential for achieving public policy goals associated with “the new power industry” structure. It is the author’s opinion that with respect to DG programs, the *Inflow & Outflow* (I&M) mechanism constitutes the most fundamental platform for cost-of-service ratemaking.

Why is that? The answer is simple, inflows and outflows are the only measured parameters associated with DG operation that inherently reflect the customer’s actual onsite usage. **Without measurement of actual power inflows and outflows, it is impossible to deploy a DG program that unlocks the full potential of customer-sited generation resources.** Unfortunately this truth is often misunderstood or neglected by both regulators and utilities alike.

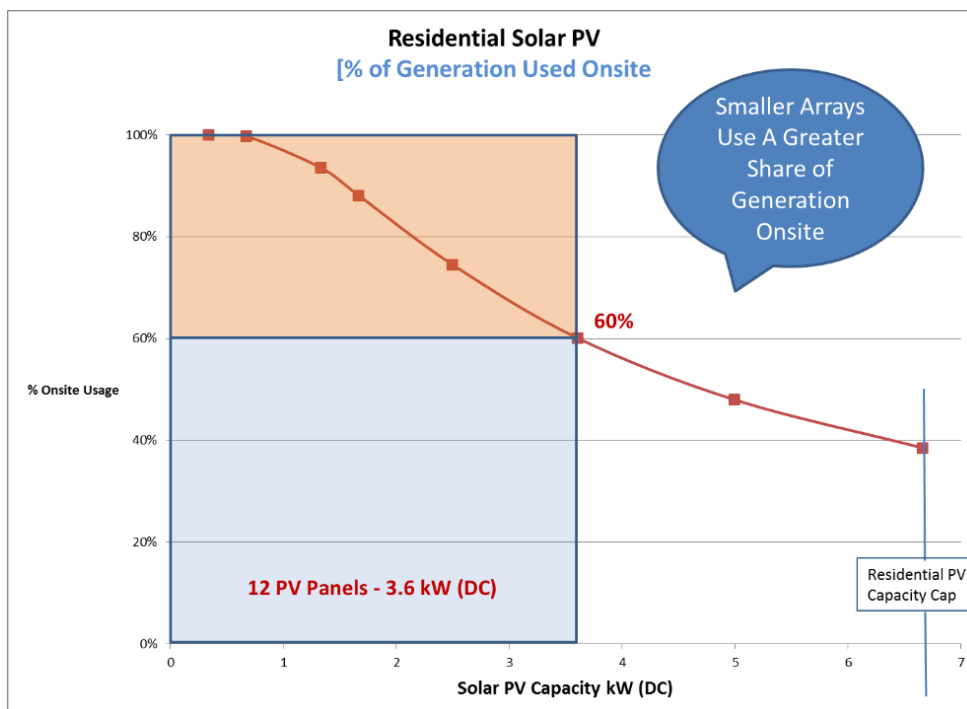
Since recognition of onsite-usage (via metered inflows and outflows) in DG tariff structure is so critical to the achievement of sound public policy objectives, the concept of onsite-usage needs to be explored in more detail.

It should be noted that a pertinent finding derived from modeling residential solar PV is that **the level of onsite usage is an inverse and non-linear function of system-size relative to the customer's base-load**. Small systems (relative to load) result in very high levels of on-site usage. For example, if an average residential customer install only one, or two solar PV panels, modeling demonstrates that nearly all of the power generated is used onsite. Conversely, large systems relative to base-load, result in a lessor, but still significant level of onsite-usage.

The regulatory implications from this finding are noteworthy. It was previously asserted that any DG mechanism that fails to incorporate measured power inflows and outflows as billing determinants, will by its very construct deviate from cost of service. It is further noted by this finding, that this deviation from cost of service is *accentuated* for those customers installing relatively small solar-PV systems (vis-à-vis their base usage).

In the typical NEM tariff, customer-sited generation-capacity is limited to that level producing an aggregate energy output equivalent to the customer's nominal annual-load (i.e. prior to installation of the DG system). This equates to approximately 6.65 kW (DC) for the average residential solar-installation in Michigan. Chart (9) below, reveals how onsite-usage increases dramatically when installed solar PV capacity falls below the effective residential system-capacity cap.

Chart 9



Due to the high installed cost of a solar PV system, many customers install PV capacity at a level below their base-usage. This results in a significantly greater level of onsite usage than would be expected with a system designed to output at the maximum qualifying cap. Twelve panels (about 3.6 kW (DC)) or less has been common in Michigan. It is acknowledged that the practice of under-sizing PV systems is expected to diminish as the solar industry continues to bring installed costs downward. However, it is this author's opinion that there will always be customers who cannot afford a luxury system. Albeit, in light of expected future cost reductions, solar PV capacity will tend to drift higher, toward the cap. The resulting decline in the nominal onsite utilization-rate will approach a minimum of approximately 40% (for solar PV customers similarly situated to Michigan customers).

In view of the desirable phenomenon of onsite usage, it is instructive to consider customer-sited DG as comparable, in effect, to the installation of an energy efficiency measure. Similar to energy efficiency, the reduced demand for grid energy caused by onsite-usage results in two effects: a reduction in retail energy (kWh) purchases by the customer (resulting in lost utility sales) and a commensurate reduction in grid usage associated with utility delivery of such energy.

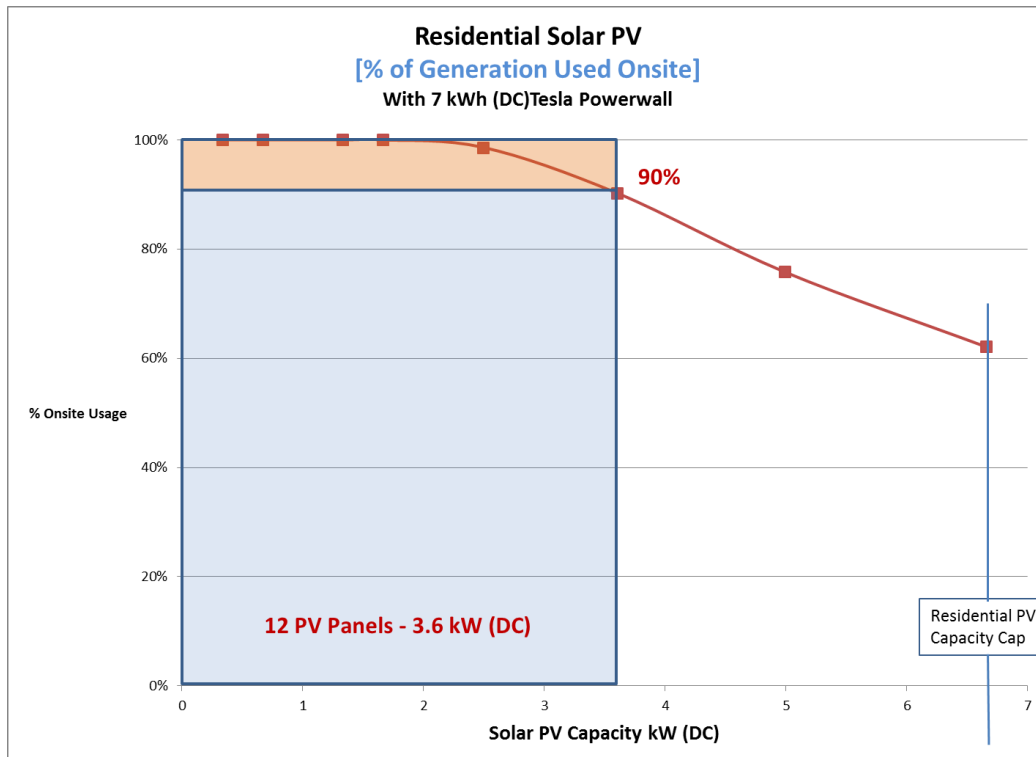
Clearly, the principal distinction between an energy-efficiency measure and customer-sited DG, is the problem-child of excess generation (outflow), due to inability to completely match system output with consumption. This is a key operational issue with customer-sited solar PV.

Load modification, panel tracking systems or orientation adjustment, can yield nominal improvements in onsite usage. However, the only practical solution to completely eliminate excess generation [outflow] is to install a complementary energy-storage system. For residential solar PV, increasing the level of onsite usage to 100% [without extensive load modification] necessarily requires a large and (at this time) prohibitively expensive energy-storage system, and so this would not be an economic choice for a grid-connected solar PV system.

Fortunately, even a relatively small battery system substantially increases onsite usage, and has other demand response benefits as well that could be extracted from any contemplated program design.

Chart (10) shows how the addition of a relatively small battery, a 7 kW (DC) Tesla Powerwall, affects the level of onsite usage for various levels of residential solar PV capacity.

#### **Chart 10**



By comparison to Chart (9), it can be seen that the level of generation consumed onsite increases from 39% to 62% at the tariff-specified generation capacity cap of 6.65 kWh. With a smaller solar PV system (consisting of 12 panels), the utilization rate increases from 60% to 90%. Both results are remarkable, considering the relatively small size of the battery [7 kWh] vis-à-vis an off-grid PV-battery system. The calculations are based on an 8,760 hour analysis, with operational objectives to: (1) time the daily battery charge and discharge cycles in a way to unload the battery during the late-afternoon peak-demand period; and (2) maximize use of the energy capacity of the battery.

In order to better understand how *battery-size* effects grid usage, the author modeled the effect of a progressively increasing battery capacity on both cumulative power inflows and outflows, for a typical residential customer having a solar PV system of 6.65 kW. See Chart (11), below.

**Chart 11**

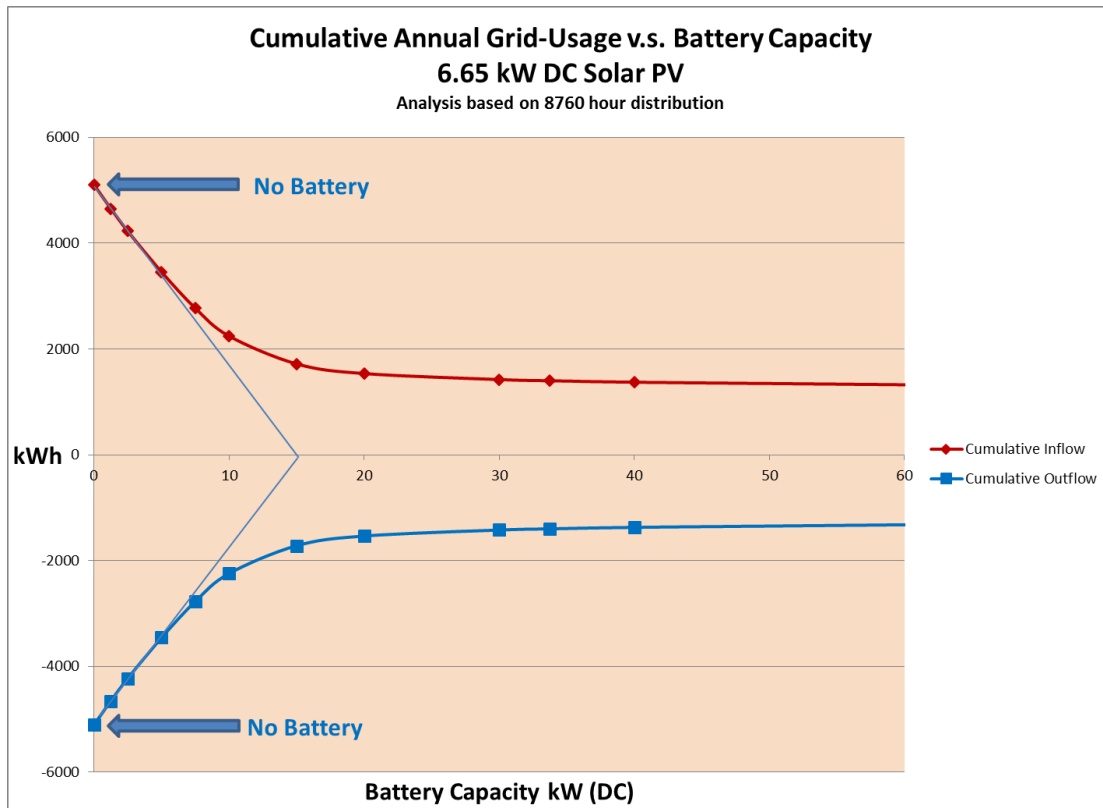
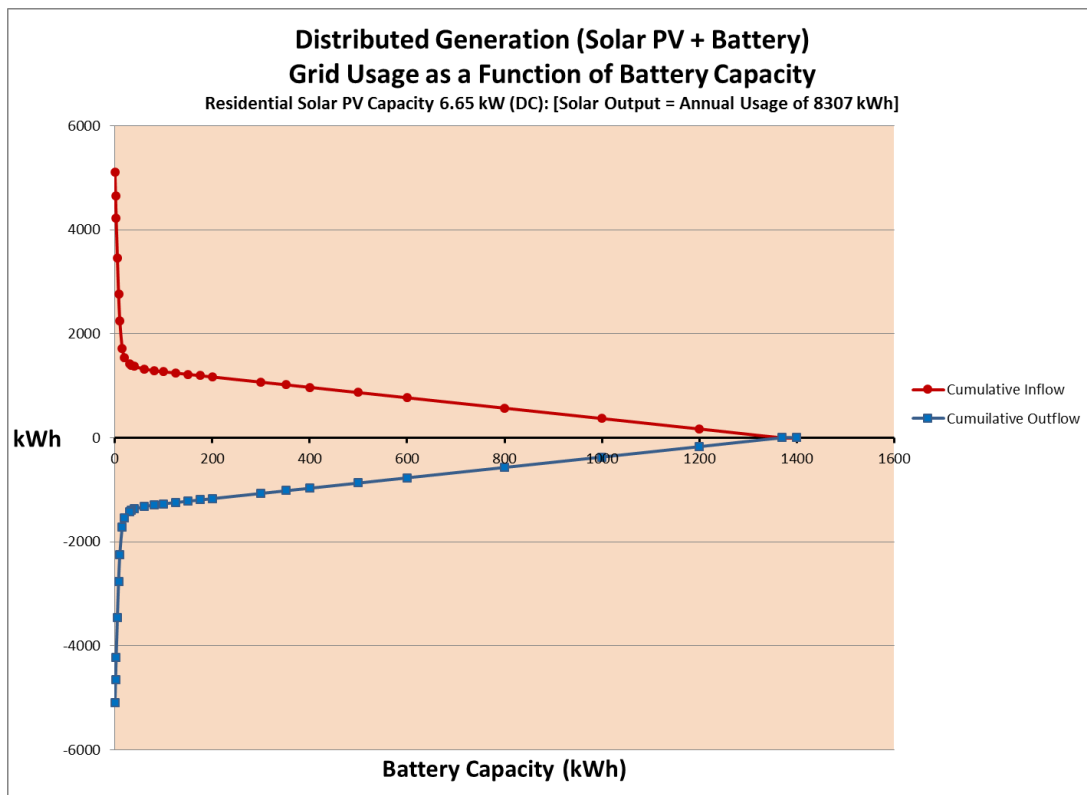


Chart (11) demonstrates that the reduction in power inflows and outflows, with increasing battery capacity, is a steep linear function for small battery sizes. At a battery capacity of approximately 10 kW, the slope of the inflow and outflow curves flatten substantially, indicating a rapidly declining impact of additional battery capacity. At this point, the Law of Diminishing Returns asserts itself, as battery capacity increases to the point that both cumulative inflows and outflows are reduced to zero. In light of this information, **for residential demand-response purposes, one could view a battery capacity of 10kW, or less, as the optimal zone of a grid-interconnected battery/DG system.**

At the other extreme, the state of having zero cumulative power inflows and outflows (over an annual period) is a significant metric because it is the technical requirement for off-grid operation. Chart (12), below, denotes an expanded view of Chart (11) whereby battery capacity is progressively increased until cumulative annual inflows/outflows are reduced to zero.

**Chart 12**



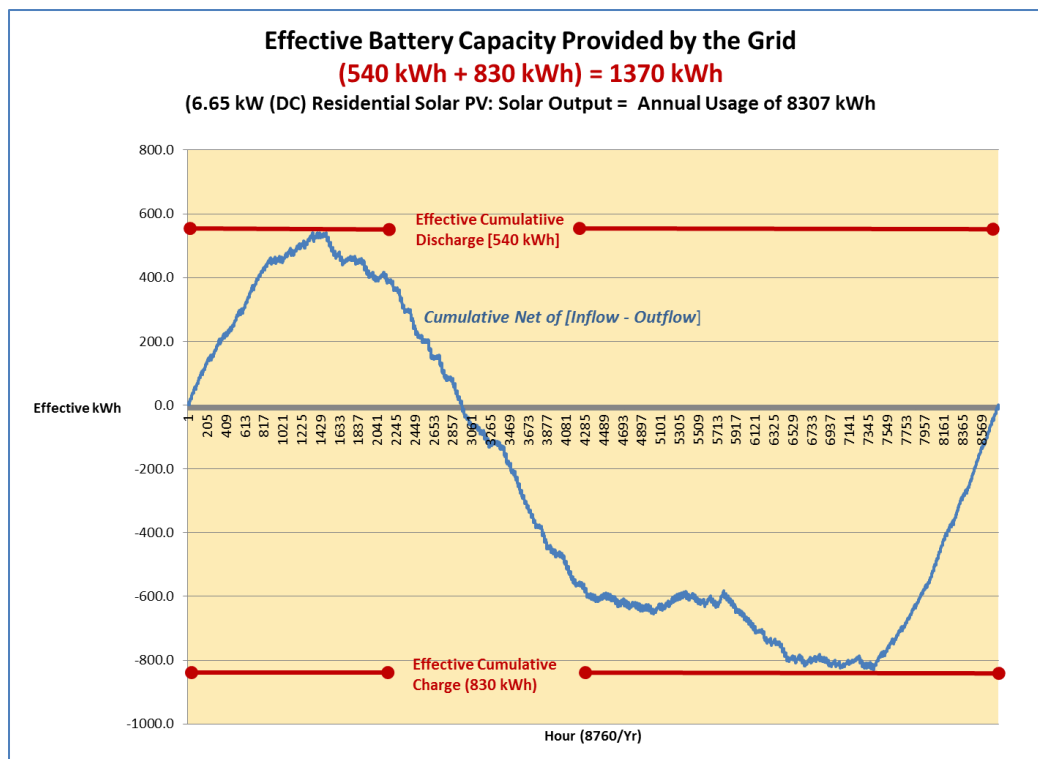
Contrary to popular misconception, the battery capacity needed to reduce power inflows/outflows to zero is very large, given two caveats that are frequently ignored when discussing the grid-defection issue: (1) there is no load modification by the customer, and (2); that no auxiliary generation is used. Given these two conditions, a customer-sited battery capacity of approximately 1,370 kWh is necessary to maintain both power inflows and outflows, at zero over the course of a year. With a battery of this capacity, a customer would be “off grid” capable. The required 1,370 kWh battery capacity was calculated on the basis of a residential customer in Michigan, having an typical annual load of 8,370 kWh, and a solar PV system with an equivalent annual output of 8,370 kWh (6.65 kW) ]. All values, including battery charge and discharge rates, inflows and outflows, and consumption and generation, were modeled on an hourly basis.

This is a surprisingly large required battery capacity. However, given the two constraints imposed, (no load modification or auxiliary generation), this system would be cost prohibitive as an actual off-grid pathway. The modeling exercise, on the other hand, is instructive, because such an onsite battery is equivalent to the *effective battery capacity provided by the grid*, via the NEM mechanism.

Chart (13) allows a direct calculation of such *effective battery capacity* for an average residential customer with a 6.65 kW solar PV system. The chart consists of a plot of the cumulative net of (Inflow – Outflow), on an hourly basis, over the course of a year. Note that the net of (Inflow – Outflow) is the foundational billing deterrent for a true NEM mechanism. Notice too, that the end-of-year net of

(Inflow – Outflow) is zero. Consequently, comparable to the off-grid pathway, the kWh balancing intrinsic to NEM would also result in an effective net-zero utility bill.

**Chart 13**



Referring to Chart (13), the maximum “positive” cumulative net-metered quantity, (540 kWh), constitutes the cumulative net draw from the grid following the 1<sup>st</sup> day of the year, up to the seasonal switch to net outflows. But under a NEM mechanism, it also represents the “grid battery” balance needed at the beginning of the calendar year to offset such late-winter power inflows. Coincident with this net “discharge” reaching its maximum point, the virtual battery balance is zero. Later in the year, the point in time that the maximum “negative” cumulative net outflow occurs, (-830 kWh), the virtual grid battery is at its peak capacity. The difference between the two values [540 - (-830) = 1,370 kWh, represents the *effective battery capacity provided by the grid* under the NEM mechanism.

What is striking, but not unexpected, is that this effective battery-capacity is equivalent to the customer-sited battery-capacity, of 1,370 kWh, previously calculated by adjusting hourly charge and discharge rates to yield zero power inflows and outflows, i.e. off-grid operation.

Establishing this equivalency is vital to understanding, and quantifying, the level of grid services being provided by NEM. Clearly, a significant balancing service is being provided by the utility pursuant to a NEM mechanism.

In light of the demonstrated equivalency, we can now say that **the effect on a customer's annual utility bill from the balancing service provided by NEM, is equivalent to the customer's use of an onsite-battery capable of reducing power outflows to zero.** This equivalency holds irrespective of the size of the generation system, as long as its output does not exceed the customer's annual base-consumption. Importantly, **the action of reducing power outflows to zero [by means of an energy storage system] is achieved by increasing onsite usage to the point that it equals the full generation output.**

We have now come full circle, having established the basis for the assertion (at the beginning of this paper) that the kWh netting process inherent to NEM has the same effect on customer bills (and utility revenues) as if the customer consumed the full solar PV output onsite.

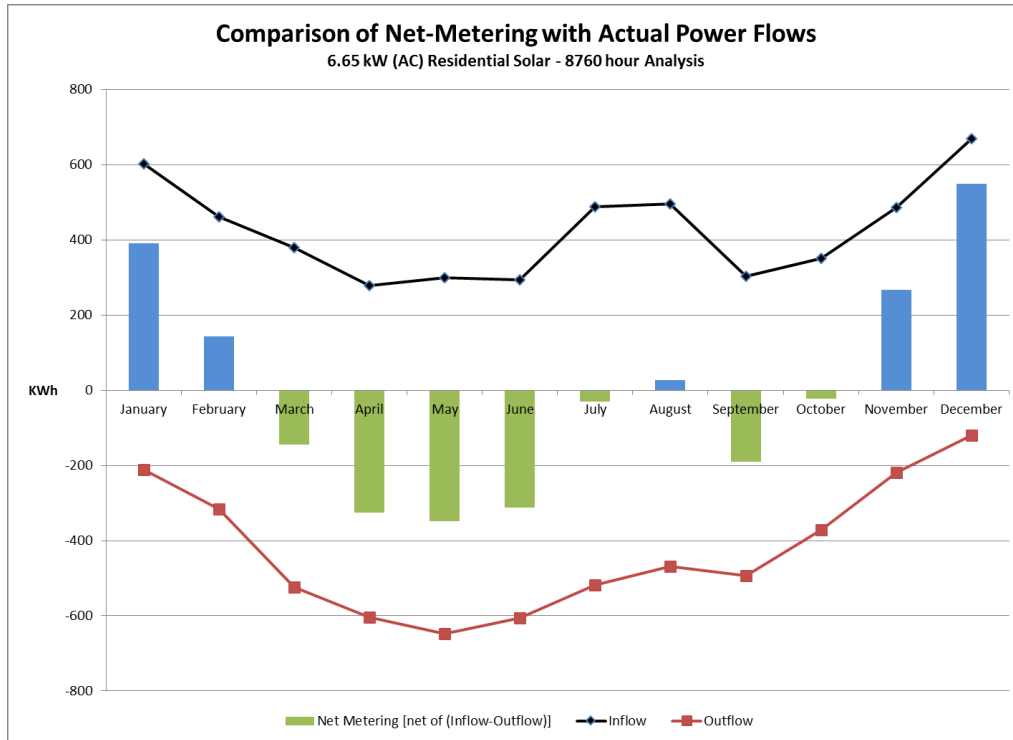
For example, a customer that installs a single solar panel, creates a physical load-reduction equal to the customer's actual onsite-usage. However, a NEM tariff induces an additional "virtual" load-reduction, such that the sum of the two (actual plus virtual) is equivalent to the entire output of the single-panel generation-system over the course of an annual period. Similarly, at the other extreme in system size, namely a customer having a generation system that has an output equal to the customer's base annual consumption, NEM can induce a total load-loss to the utility, i.e. a "virtual" grid defection.

It is obvious that regulatory induced load-loss is a core issue with NEM. But the heart of NEM deficiencies can only be seen from an operational-efficiency perspective. NEM heavily distorts pricing-signals that could otherwise drive efficient customer behavior. As a result, the author strongly asserts that NEM cannot be relied upon as a regulatory platform for attaining goals associated with the "future electric-power industry", such as those related to expanded use of distributed generation, customer-sited energy storage, or enhanced demand-response resources.

Chart (14) below, juxtaposes NEM's billing determinant, with cumulative monthly inflows and outflows. The chart reveals strong deviation between the two.



Chart 14



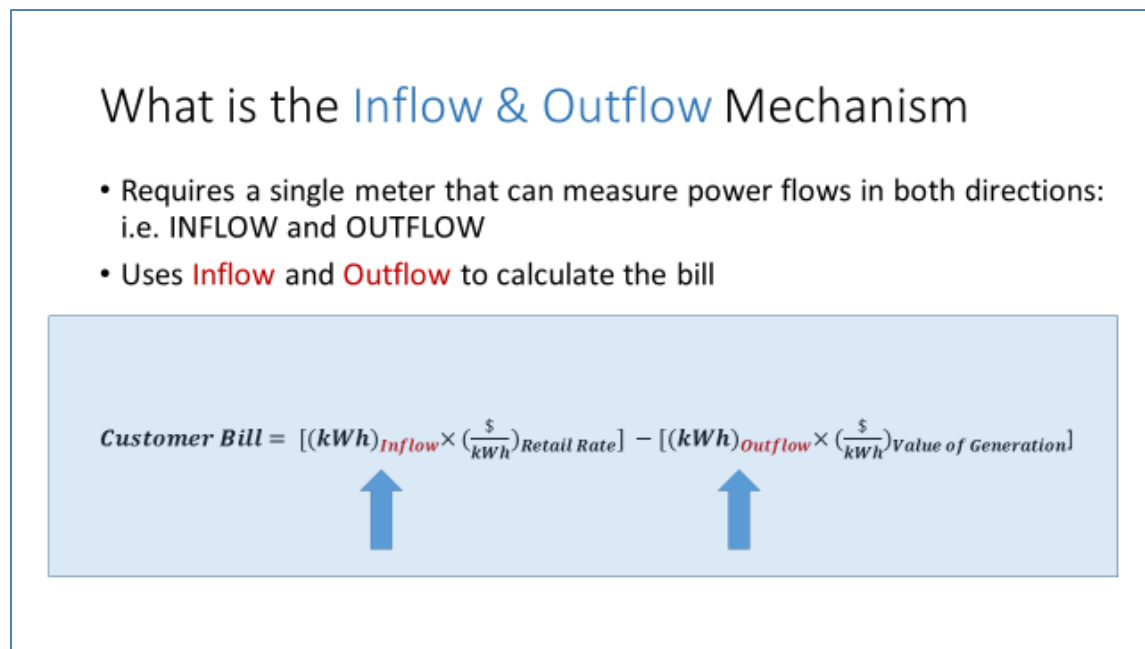
True NEM is implemented by netting over the billing period associated with the customer’s retail sales rate-schedule. Obviously, netting over monthly billing-periods thoroughly obfuscates inflow and outflow related price-signals, rendering NEM ineffective as a tool to achieve 21 century energy-policy goals. True NEM cannot be described as anything but “long in the tooth”.

Some utilities have implemented a “modified” net metering for commercial and industrial DG customers in which netting occurs over *time-of-use* billing blocks. If the modified NEM takes a step further, and prices carry-forward [from one netting period to the next] at a reasonable value-of-generation, the mechanism could be viewed as an I&O “lite” mechanism. However, seeing that no additional complexity is required to implement a true I&O mechanism vis-à-vis a modified NEM, there exists no real impediment to move directly to a true I&O mechanism, particularly in light of the fact that the modified NEM falls short of providing the full panoply of tools and economic incentives for customers to optimize DG operations, that are derived from a true I&O mechanism.

At this point, a fundamental proposition of this paper will be restated: **a DG mechanism that does not use metered power inflows and outflows as billing determinants is in conflict with true cost-of-service principles.** Utility rate schedules may very well include sophisticated elements such as dynamic pricing and/or demand charges, but if the DG mechanism yields customer bills based on: (1) inferred (base) consumption; (2) generation; or (3) the net of [inflow – outflow], it will fail to capture the true cost-of-

service, and will convey inaccurate pricing-signals that induce sub-optimal customer behavior. Chart (15) below delineates the Inflow & Outflow mechanism for a simple commodity based rate design.

Chart 15



These findings have implications for regulators considering the Buy-all Sell-all (BASA) mechanism as a replacement for NEM. The BASA mechanism, similar to the NEM mechanism, does not reference actual (metered) power inflows or outflows in the calculation of charges and credits, and thus is invariant to changes in the level of onsite usage in the calculation of retail rates. Like NEM, the BASA mechanism fails to transmit price signals that drive efficient operation. Chart (16), below, defines the mechanism for a simple commodity-based rate-design.

Chart 16

## What is the Buy All – Sell All Mechanism

- Requires two meters: one bidirectional and one generation meter
- Uses Inferred Consumption, and Generation to calculate the bill

$$\text{Customer Bill} = [(kWh)_{\text{Consumption}} \times (\frac{\$}{kWh})_{\text{Retail Rate}}] - [(kWh)_{\text{Generation}} \times (\frac{\$}{kWh})_{\text{Value of Generation}}]$$


The BASA mechanism is based on a deeming process. All generation is deemed to have been injected into the utility grid, and likewise, all consumption is deemed to have been served by utility system-supply. As a result, the rate structure of the BASA mechanism requires two utility meters. This enables the calculation of two billing determinants; metered generation, and inferred consumption.

Metered generation is invariant to the level of onsite usage on its face. For example, a solar PV system would be interconnected to a utility generation-meter (typically at cost to the customer) directly downstream of the inverter, and as a result reflects gross AC output. It is logical that the customer's base consumption is also invariant, since it constitutes the actual electric-load sans generation offset, (i.e. sans onsite usage).

Unfortunately, a DG customer's actual electrical load cannot be physically metered, and must be inferred by quantities that can be metered. There may be some question as to whether or not "inferred" consumption is also invariant, and it can be shown that it is, as follows.

The process of inferring base consumption is a calculation, based on the energy balance:

$$[\text{Generation} + \text{Inflow} = \text{Consumption} + \text{Outflow}] \quad \text{Equation (12)}$$

Rearranging:

$$\text{Consumption} = \text{Generation} + [\text{Inflow} - \text{Outflow}] \quad \text{Equation (13)}$$

Equation (13) is used to infer consumption, using the two metered quantities: generation and [inflow – outflow]. Depending on whether or not the BASA mechanism uses time-based pricing, the latter variable can be measured by a vintage analog meter, or a digital smart meter. The sum of the two metered

quantities constitutes the customers actual electrical load, and is used as the “consumption” billing determinant.

Regarding Equation (13), it has previously been shown that:

$$\text{Inflow} = [\text{Consumption} - \text{Onsite Usage}] \quad \text{Equation (14)}$$

And:

$$\text{Outflow} = [\text{Generation} - \text{Onsite Usage}] \quad \text{Equation (15)}$$

It is clear that by subtracting Equation (15) from Equation (14), that onsite-usage cancels out of the term [Inflow – Outflow]. Thus the net-metered quantity [inflow – outflow] is itself invariant to the level of onsite-usage. The upshot being that the overall mathematical expression for “inferred” consumption is invariant to the level of onsite-usage.

The BASA mechanism’s deficiencies can be visualized by referring to Chart (17) below.

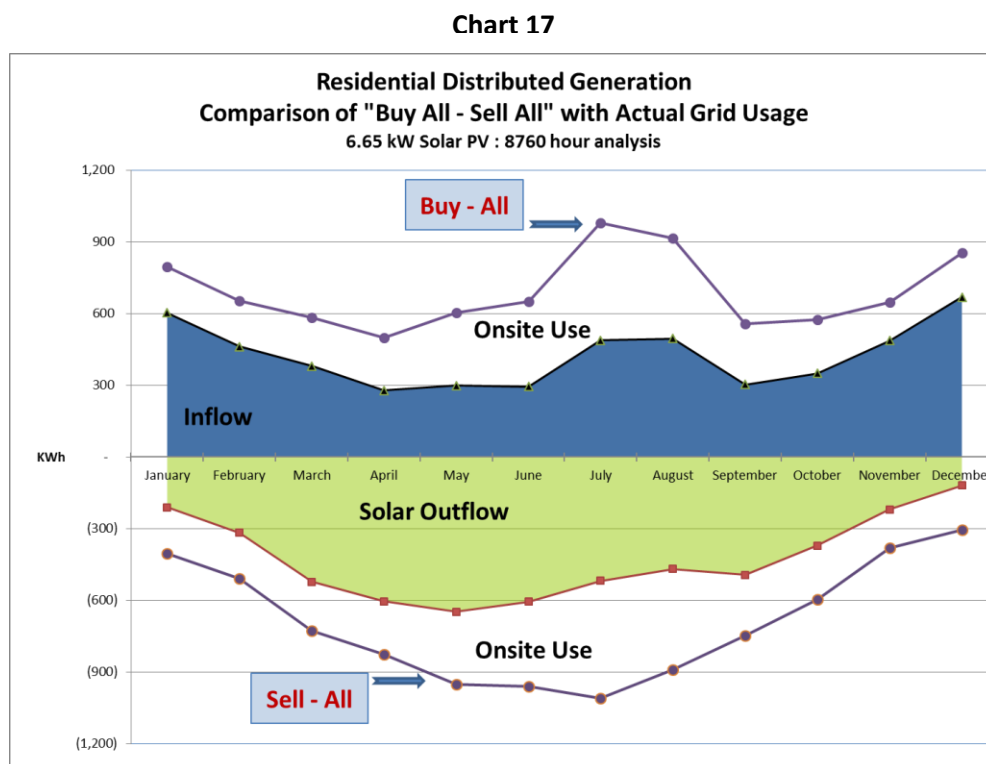


Chart (17) is the same as Chart (5) except that it has been relabeled. The BASA billing determinants can be seen as the top and bottom lines, which are consumption and generation, respectively.

With reference to Chart (17) It is apparent that the BASA billing determinants [consumption and generation] diverge from the cost-of-service based billing determinants, [inflow and outflow], by the (kWh) level of onsite-usage (the white bands) separating the two sets of billing determinants from each

other. It is clearly apparent that the net customer bill is calculated from the BASA billing determinants as if none of the generation was consumed onsite. **The BASA mechanism overstates the consumption bill (which should be based on the smaller metered inflow) and likewise overstates the credit (which should be based on the smaller metered outflow).**

Although Chart (17) conveys the existence of these two deviations from cost-of-service, it provides insufficient information to understand the combined impact on a BASA customer's bill, especially considering that the two errors interact from opposite directions. For this, it is necessary to take a mathematical approach as follows.

First, we assume that the full (per kWh) retail rate for both the inflow and consumption are identical, since technically they are both "inflow" from the perspective of utility grid operations. It is also assumed that the same energy and capacity credits (\$/kWh and \$/kW) for utility purchases of excess generation applies. These assumptions are made to simplify the expressions, and have no impact on the conclusions reached.

With these assumptions, under the BASA and I&O mechanism, typical residential customer bills are respectively:

**Customer Bill under the *Buy all – Sell all (BASA)* mechanism:**

**Equation (16)**

$$= \text{Customer Charge} + (kWh)_{\text{Consumption}} \times \left( \frac{\$}{kWh} \right)_{\text{Full Retail Rate}} \\ - (kWh)_{\text{Generation}} \times \left( \frac{\$}{kWh} \right)_{\text{Value of Generation}} - \text{Capacity Credit}_{\text{BASA}}$$

**Customer Bill under the *Inflow & Outflow* mechanism:**

**Equation (17)**

$$= \text{Customer Charge} + (kWh)_{\text{Inflow}} \times \left( \frac{\$}{kWh} \right)_{\text{Full Retail Rate}} \\ - [(kWh)_{\text{Outflow}} \times \left( \frac{\$}{kWh} \right)_{\text{Value of Generation}}] - \text{Capacity Credit}_{\text{I\&O}}$$

Subtracting Equation (12) from Equation (11) results in an expression equivalent to the BASA deviation from cost of service:

**BASA Deviation from Cost of Service**

**Equation (18)**

$$= [(kWh)_{\text{Consumption}} - (kWh)_{\text{Inflow}}] \times \left( \frac{\$}{kWh} \right)_{\text{Retail Rate}} - [(kWh)_{\text{Generation}} - (kWh)_{\text{Outflow}}] \\ \times \left( \frac{\$}{kWh} \right)_{\text{Value of Energy}} - [\text{Capacity Credit}_{\text{BASA}} - \text{Capacity Credit}_{\text{I\&O}}]$$

By means of the energy balance: [Consumption - Inflow] = Onsite Usage; and [Generation – Outflow] = Onsite Usage, the deviation from cost of service, Equation 18, can be simplified to:

**BASA Deviation from Cost of Service**

**Equation (19)**

$$= [(kWh)_{\text{Onsite Usage}} \times \left( \frac{\$}{kWh} \right)_{\text{Retail Rate}} - [(kWh)_{\text{Onsite Usage}}] \times \left( \frac{\$}{kWh} \right)_{\text{Value of Energy}} - [Capacity Credit_{BASA} - Capacity Credit_{I\&O}]$$

Equation (19) constitutes the deviation from true cost-of-service associated with the BASA mechanism. However, the relationship between the capacity credits can also be expressed in terms of onsite usage as follows

For a solar PV system the effective capacity (kW) provided by the DG system is a function of the system's nameplate capacity and its *effective load carrying capacity* (ELCC).

$$(kW)_{\text{Effective}} = (kW)_{\text{Nameplate}} \times ELCC$$

**Equation (20)**

Under a BASA mechanism, the entire generation capacity is “sold” to the utility. Thus, capacity credits are readily calculated as:

$$Capacity Credit_{BASA} = (kW)_{\text{Nameplate}} \times ELCC \times \left( \frac{\$}{kW} \right)_{\text{Value of Capacity}}$$

**Equation (21)**

Capacity credits under a BASA mechanism are necessarily larger than under an I&O mechanism since the former reflects gross-generation capacity, and the latter reflects actual power outflows, which are necessarily smaller, since onsite usage needs to be netted from gross generation. The difference between the two can be approximated through application of an additional fractional multiplier:

$$\left[ \frac{Cumulative Outflow}{Cumulative Generation} \right]$$

Thus:

$$Capacity Credit_{I\&O} = [Capacity Credit_{BASA} \times \frac{Cumulative Outflow}{Cumulative Generation}]$$

**Equation (22)**

or

$$= [(kW)_{\text{Nameplate}} \times ELCC] \times \frac{Cumulative Outflow}{Cumulative Generation} \times (kW)_{\text{Value of Capacity}}$$

**Equation (23)**

Inserting Equation (21) and Equation (23) into Equation (19) yields:

**BASA Deviation from Cost of Service**

**Equation (24)**

$$= [(kWh)_{\text{Onsite Usage}} \times \left(\frac{\$}{kWh}\right)_{\text{Retail Rate}} - \left\{ [(kWh)_{\text{Onsite Usage}}] \times \left(\frac{\$}{kWh}\right)_{\text{Value of Energy}} + \right. \\ \left. (kW)_{\text{Nameplate}} \times ELCC \times \left[1 - \frac{\text{Cumulative Outflow}}{\text{Cumulative Generation}}\right] \times \left(\frac{\$}{kW}\right)_{\text{Value of Capacity}} \right\}$$

Simplifying Equation 24:

**BASA Deviation from Cost of Service**

**Equation (25)**

$$= [(kWh)_{\text{Onsite Usage}} \times \left(\frac{\$}{kWh}\right)_{\text{Retail Rate}} - \left\{ [(kWh)_{\text{Onsite Usage}}] \times \left(\frac{\$}{kWh}\right)_{\text{Value of Energy}} + \right. \\ \left. (kW)_{\text{Nameplate}} \times ELCC \times \left[\frac{\text{Onsite Usage}}{\text{Cumulative Generation}}\right] \times \left(\frac{\$}{kW}\right)_{\text{Value of Capacity}} \right\}$$

Pursuant to a BASA mechanism, **the entire deviation from cost-of-service is related to generation used onsite**. Equation (25) demonstrates that the cost-of-service errors associated with the BASA mechanism combine in such a way that the net deviation is equivalent to the utility charging-back each DG customer the full retail rate for reduced (i.e. lost) utility revenues associated with that specific customer's actual load reductions, offset by the capacity value of generation used onsite. Thus, the DG customer is both overcharged and over-credited.

Clearly, Equation (25) demonstrates that the BASA mechanism necessarily results in **utility lost sales [i.e. onsite usage] being charged-back directly to the distributed generation customer that reduced their retail electric purchases**, rather than being recovered in a general rate proceeding as an allocation to the customer class as a whole (e.g. the residential customer class). This explains the large divergence in customer bills between the BASA mechanism and the I&O mechanism (i.e. cost-of-service).

Advocates of the BASA mechanism, with good intention, intend to address the core issue of the NEM program: that participation in NEM program results in significant reduced utility revenues associated with utility load-losses. Unfortunately, the BASA solution to restore revenues goes beyond parity with cost-of-service and violates a longstanding regulatory principle related to retroactive ratemaking, i.e. the direct billing of lost-revenues to a customer.

It was previously mentioned that onsite-usage may be thought of as analogous to energy efficiency, in that it results in a direct reduction in retail (kWh) purchases by the customer and commensurately reduced power inflows from the utility distribution grid. The generally accepted regulatory method of dealing with energy efficiency program lost-revenues is through a general rate case, or possibly via a decoupling mechanism, such as a lost sales tracker. In fact, both methods could be used to make a utility whole from DG induced lost revenues, **but in either case lost-revenues are never billed back to individual customers**.

Regarding compensation for "excess" generation, the development of principles leading to a fair "value-of-generation" (including mathematical algorithms for quantifying) is a distinctly different matter than the issue of laying a foundation for DG program structures, and will not be addressed in this paper.

Suffice to say, it is the author's opinion that efforts to establish a fair compensation are necessary, but premature if the regulatory mechanism being considered is not a cost-of-service based foundation.

Thus, the determination of the "value of generation" remains as a controversial issue, even if the I&O mechanism is selected to replace NEM. However, the I&O mechanism is the only regulatory alternative that limits the impact of mispricing generation credits to the actual power outflows injected into the distribution grid. Any error in setting of a "value of generation" credit is compounded by a DG program structure that does not use metered outflows as billing determinants.

With non-cost-of-service based DG programs, such as the BASA mechanism, the net bill, in practice, needs a significant adjustment to the fair "value of generation" credit, to encourage customer-sited DG installations, and this adjustment is the direct result of overstating grid usage by equating it to inferred consumption.

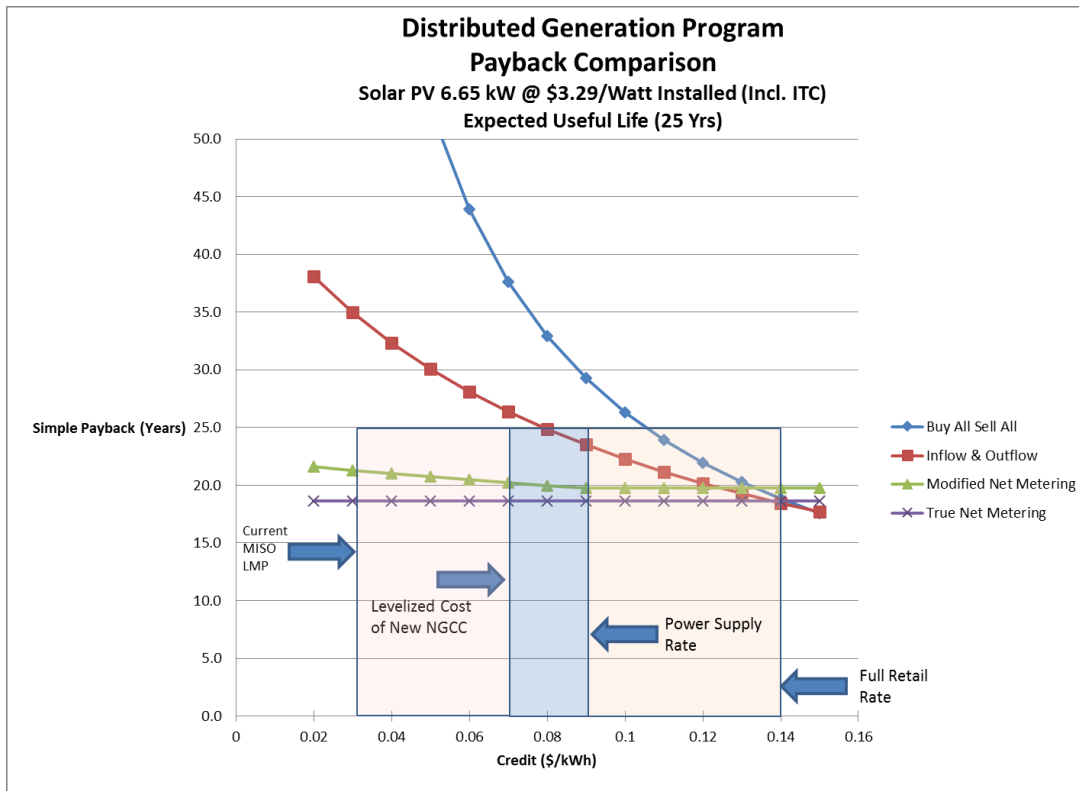
An example of this adjustment was the initiative in Maine to determine a value of generation, with an incentive adder to improve customer payback. The Maine proposal, proffered by the Maine Public Service Commission incorporates a well-reasoned effort to determine the value-of-generation. However, since the credit is inserted into a BASA rate structure [that necessarily overstates inflow and outflow via the use of imputed consumption and total generation], the proposal resorts to incentive payments for the "sale" of DG generation output in order to make some semblance of economic payback for customer-sited solar.

This underscores the BASA mechanism's focus on bill credits for generation. Economic incentives under a BASA mechanism is singular. The only financial incentive exclusively related to efficient operation of the DG system is the incentive to maximize output, and to do so at the time periods where the "value of generation" is priced the highest. Therein lies the hitch. The mechanism distorts the innate measure of operational efficiency - which is to reduce power inflows, and to do so at the times of highest retail rate. It is true that a BASA customer can modify their load profile. However, since the consumption bill is the same as any similar situated non-DG customer, the financial incentive to do so is identical to that of a full-requirements customer.

The author has modeled the various forms of DG programs to see how they compare on a simple payback basis for various levels of value-of-generation. Chart (18) below delineates the result.

#### **Chart 18**





Referring to Chart (18), the box represents a viable range of simple paybacks, recognizing that the nominal expected useful life of a residential solar PV system is approximately 25 years. It is bounded on the left, by the current average (energy only) MISO wholesale electric rate. The upper bound is the full residential retail rate for Consumers Energy. Significantly exceeding the full retail rate generally requires the recognition of external benefits and was not modeled. The I&O mechanism can be considered cost-of-service, and thus the standard for comparison.

All DG mechanisms converge (approximately) with true NEM at a credit equal to the full retail rate. As expected, true NEM, is invariant to the level of credit, because it is a kWh balancing structure. It results in the shortest payback periods. Modified NEM has marginally longer paybacks, closer to the cost-of-service DG structure, because it converts the monthly carry-forward to a dollar based credit, thus mimicking the pricing of power inflows in a I&O mechanism. It was also assumed that Modified NEM also limits credits to the following month's Power Supply Cost Recovery (PSCR) charges, resulting in a bend in the curve at the PSCR. It can be seen that the BASA mechanism results in substantially longer paybacks than resulting from cost-of-service, especially with credits at or below the levelized cost of a new Gas Combined Cycle Power Plant (NGCC).

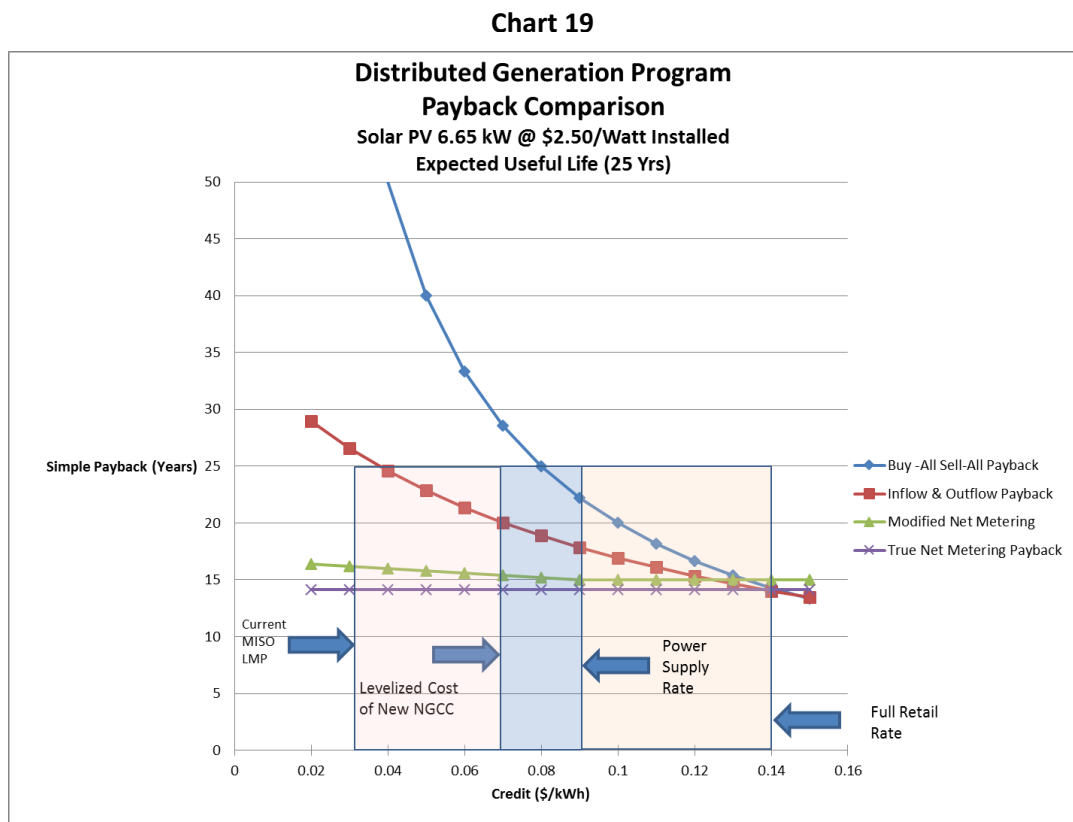
Surprisingly, the I&O mechanism did not result in a valid payback at a credit level near the proxy plant credit. This is a near miss, but significant nonetheless. The proxy plant method, is a foundational pricing method often used for DG sales pursuant to PURPA, and which can be viewed as a simple analog for long-term wholesale market prices. The failure to pay back at the proxy plant rate, using a cost-of-

service DG mechanism, is clearly a manifestation of the difficulty of residential solar PV to compete with retail electric rates in Michigan - at this time. With continued reductions in the all-in cost of solar PV, cost of service based distributed generation programs should provide a positive net present value.

Referring again to Chart (18) the BASA mechanism, in contrast, is so far out of bounds that it would essentially collapse the emerging residential solar PV industry in Michigan (and those states similarly situated). At the proxy plant credit level, the simple payback for BASA is approaching 40 years. Even at a credit level approximately equal to the total Consumers Energy PSCR (including fixed capacity costs and transmission costs) of approximately 9 cents per kWh, the BASA mechanism results in an untenable payback of near 30 years.

A lower installed cost of solar PV (at \$2.50 per watt) was also modeled, and the I&O mechanism demonstrated a solid payback. An I&O based DG mechanism should be expected to be a long-term solution, helping to drive down installed solar PV costs. If necessary, regulators could transition to a cost-of-service based DG mechanism by including a limited-term adder to the value-of-generation.

See Chart (19) below for solar PV payback at the lower installed cost of \$2.50 per watt.



With a credit at the current levelized cost of a new NGCC plant, of approximately 7 cents per kWh, the I&O mechanism results in a reasonable payback of 20 years. However, irrespective of the numerical value of the fair value-of-generation, both Chart (18) and Chart (19) suggest that the I&O mechanism lies

in the sweet spot, midway between NEM and the BASA mechanism. It is the author's opinion that the I&O mechanism could be a reasoned compromise between those wanting to retain NEM, and those advocating for a BASA option.

### **The Inflow & Outflow Mechanism: Conclusion**

It should be clarified, that though the I&O mechanism has been referred to as a compromise regulatory structure, this does not imply that the BASA mechanism is merely a matter of preference. The BASA is a failed regulatory mechanism. It is fundamentally inconsistent with the actual grid usage of DG customers and cannot yield a cost-of-service based DG tariff. It is difficult, if not impossible for BASA mechanisms to get both cost and compensation right. Because it intrinsically over-estimates billing determinants, it necessarily leads to efforts to substantially overcompensate for the value of generation. If incentives are needed or desired to stimulate developing markets for customer-sited renewable energy, then it is the author's opinion that the logical starting point to quantify such incentives is the true cost-of service, and that cannot be determined without reference to a DG customer's power inflows and outflows.

Several undesirable outcomes prevail when NEM alternatives are created without a proper understanding of the relationship of power inflows, outflows and grid usage. Without true cost-of-service principles as a starting point, arbitrary rate designs ensue; examples include minimum bills, or arbitrarily large deviations from reasonable value-of-generation credits.

Principles of good rate-design dictate that minimum bills always be a last choice, when no other options are workable. Customers fall into a bell curve, and those at the tail are significantly impacted by minimum bills. Without reference to actual grid usage, measured as power inflows, minimum bills constitute an arbitrary proxy to recover the cost of grid services uncompensated by NEM.

Demand charges only applied to residential DG, but not to full-service customers are another pitfall, since such approaches create a tilted playing field. This is another arbitrary method of recovering the uncompensated cost of grid services associated with NEM.

This paper started with a discussion of the recent flurry of activity to replace true NEM with a DG mechanism that corrects for revenue losses being incurred by utilities, and that are being borne by non-DG customers. The NEM related revenue losses seen by electric utilities are the result of complex interactions. We have seen that breaking DG system dynamics into its components is the only way to understand the deficiencies of NEM, and the road to developing a workable replacement. The Inflow & Outflow Mechanism strikes the best balance, and is inherently a cost-of service based DG program foundation.

MSU IPU  
ADVANCED REGULATORY STUDIES PROGRAM:  
RATEMAKING, ACCOUNTING, FINANCE, AND ECONOMICS  
2017

**A Reasoned Analysis for a New Distributed-Generation Pricing  
Mechanism for Electric Utilities**

Robert G. Ozar P.E.  
Assistant Director, Electric Reliability Division  
Michigan Public Service Commission  
October 4, 2017

# Outline

- 1. Introduction**
2. Foundations
3. Modeling overview
4. Onsite-usage analysis
5. Cost-of-Service implications of DG study results
6. Economic & payback analysis



# Legislative Directives to the Michigan Public Service Commission

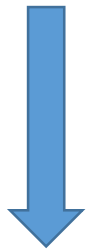
PA 341 Sec. 6 (a) (13)

...**the commission** shall conduct a study on an appropriate tariff reflecting an equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program under the clean and renewable energy and waste reduction act...

...**the commission** shall approve such a tariff for inclusion in the rates of all customers participating in a net metering or distributed generation program...

# Hierarchy of Legislative Directives

The commission shall conduct a study:



- on an appropriate tariff
- reflecting an equitable cost of service
- for utility revenue requirements

for customers who participate in a net metering program or distributed generation program

“tariff”

DG Pricing  
Mechanism

# Primary Objective

**To develop a new approach to replace Net Energy Metering\*  
for renewable generation under 150 kW, and for methane digesters up to  
550 kW**

- That allows for **traditional cost-of-service** methods to allocate costs, and thus determine a fair cost-of-service
- That has **billing determinants that strongly connect to actual grid usage**, and thus provides **accurate and transparent price signals**:
  - Inducing optimal DG system operations
  - That fairly monetizes the value of customer participation in **demand response, load control**, and **energy efficiency** actions, and thus equitably contributes toward the purchase of advanced technologies that allow such activities
- Retains DG as a reasonable/economic option for customers

\* Subject to PA 342, Sec. 183



# Secondary Objectives

- To determine if it is necessary to create **specific DG rate classes** for “solar, solar/battery, or other renewable energy systems” for allocating costs in a COSS
- To determine a **valuation method** for customer-sited generation that is injected into the grid (excess generation)
- To determine whether **credit for generation capacity/energy** should be reflected:
  - ***on a class basis*** [ i.e. outflow as an offset to demand/energy allocations (inflow) in the COSS]; or
  - ***on an individual customer basis***, [i.e. as bill credits for DG capacity/energy available to the grid (per kWh and kW credit)]

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# Distributed Generation (DG) Program Regulatory Principles

All DG pricing mechanisms are variations of three foundational approaches:

- **(1) Grid-based balancing service**
- **(2) Retail customer as Small Power Producer (SPP)**
- **(3) Actual power inflows and outflows as billing determinants**

# DG Mechanisms

- **Balancing services**
  - **True net-metering** operates as an uncompensated (free) kWh balancing service [grid as battery]
  - **Modified net-metering** is a billing or pricing-period balancing-service in which net excess generation is converted to a \$ credit (applied to future monthly bills)
- **Retail customer as Small Power Producer** (generation is separately metered)
  - **[True feed-in tariff]** Generation is interconnected upstream of the utility billing meter
  - **[Buy-all Sell-all]** Generation is interconnected downstream of the utility billing meter (at the customer's service panel)
- **Inflows and outflows as billing determinants**
  - **[Inflow & Outflow Mechanism]** Power inflows are retail purchases, power outflows credited as if generated by a SPP

# Net Energy Metering Pricing Model

Uses net of **[Inflow – Outflow]** to calculate the customer bill:



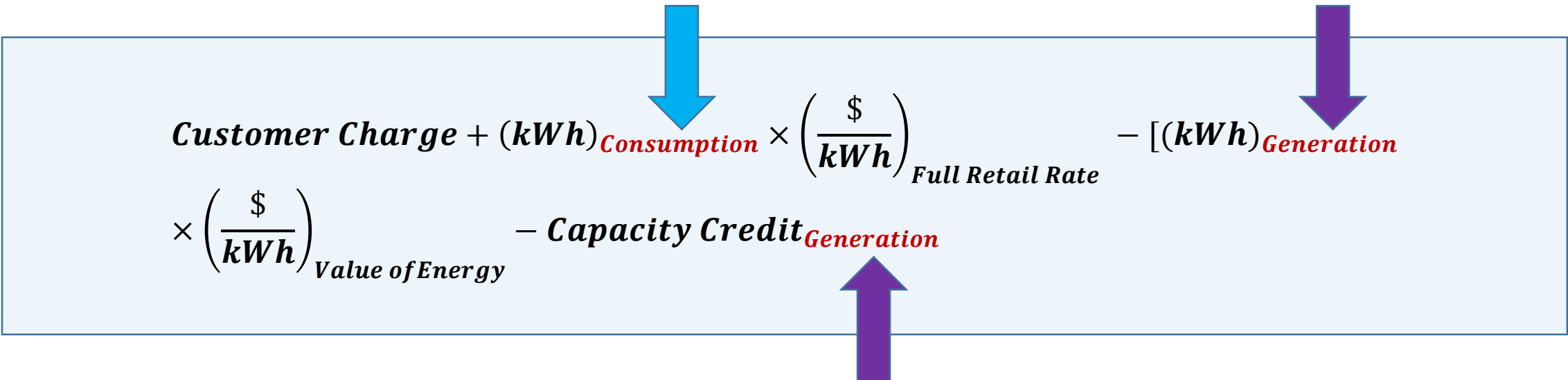
$$\text{Customer Charge} + (\text{kWh})_{[(\text{Inflow} - \text{Outflow}) + \text{CF}]} \times \left( \frac{\$}{\text{kWh}} \right)_{\text{Full Retail Rate}} \quad \text{If } (I - O) + \text{CarryForward} > 0$$

or = *Customer Charge*

*If  $(I - O) + \text{CarryForward} \leq 0$*

# Buy-all Sell-all Pricing Model

Uses **Consumption** and **Generation** to calculate the customer bill:

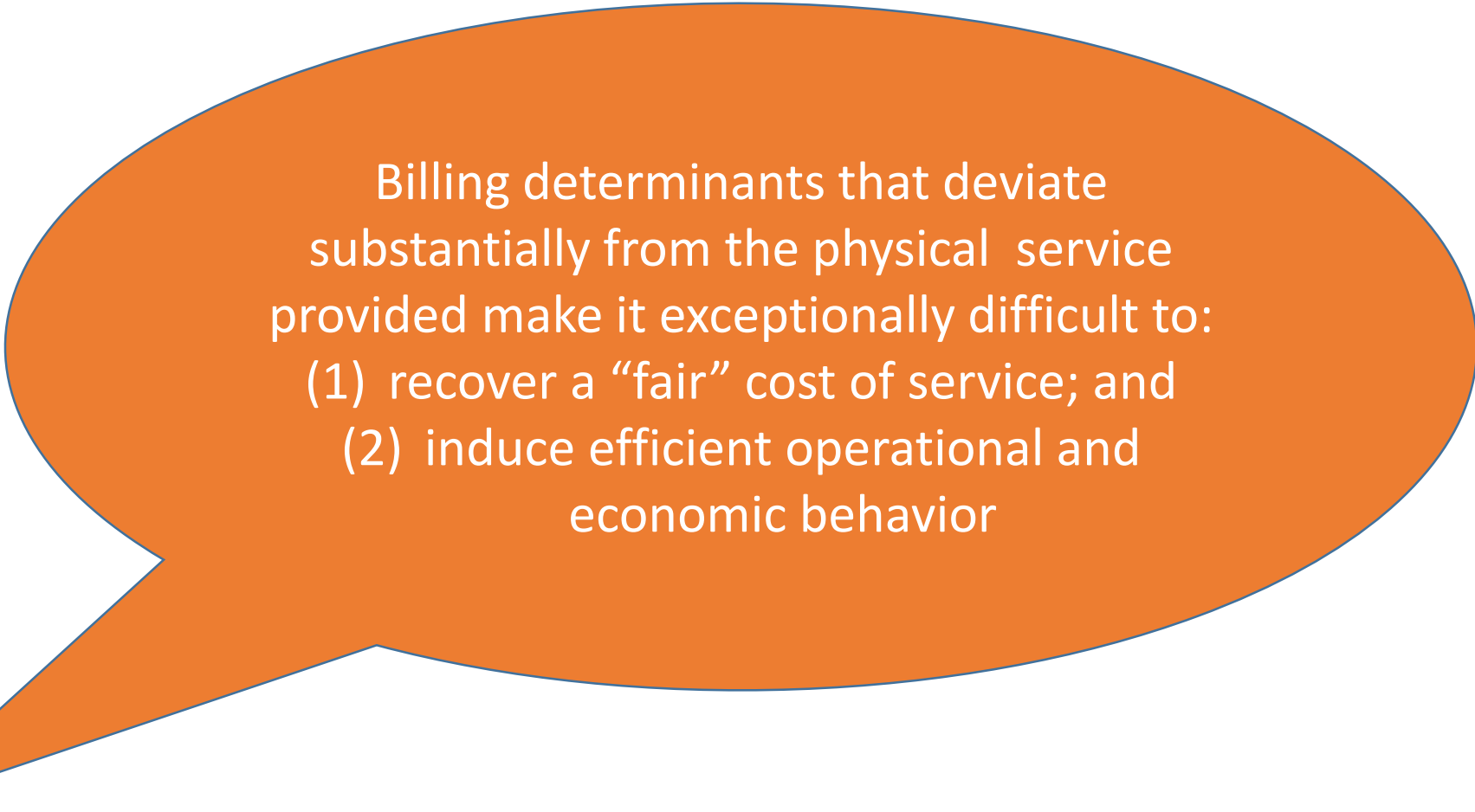

$$\begin{aligned} & \text{Customer Charge} + (kWh)_{\text{Consumption}} \times \left( \frac{\$}{kWh} \right)_{\text{Full Retail Rate}} - [(kWh)_{\text{Generation}} \\ & \times \left( \frac{\$}{kWh} \right)_{\text{Value of Energy}} - \text{Capacity Credit}_{\text{Generation}} \end{aligned}$$

**Based on Nameplate Capacity:**  
**e.g.**  
 $ELCC \times \text{Capacity}_{\text{Nameplate}}$

# Traditional DG Pricing Mechanisms were Designed to Promote Market Adoption of Nascent Renewable Technologies

- **Net Energy Metering (NEM):** *understates* cost-of-service
  - By definition true NEM applies the standard retail-rate to a customer's **net purchases** and that precludes customer bills from reflecting COS
- **Buy-all Sell-all (BASA):** *overstates* COS
  - Uses billing determinants that conflict with actual power flows
  - High “feed in” or “value of solar” credits needed to provide economic payback

# DG Pricing-Mechanism Conundrum

A large orange speech bubble with a blue outline, pointing towards the bottom left. It contains text about billing determinants.

Billing determinants that deviate substantially from the physical service provided make it exceptionally difficult to:

- (1) recover a “fair” cost of service; and
- (2) induce efficient operational and economic behavior

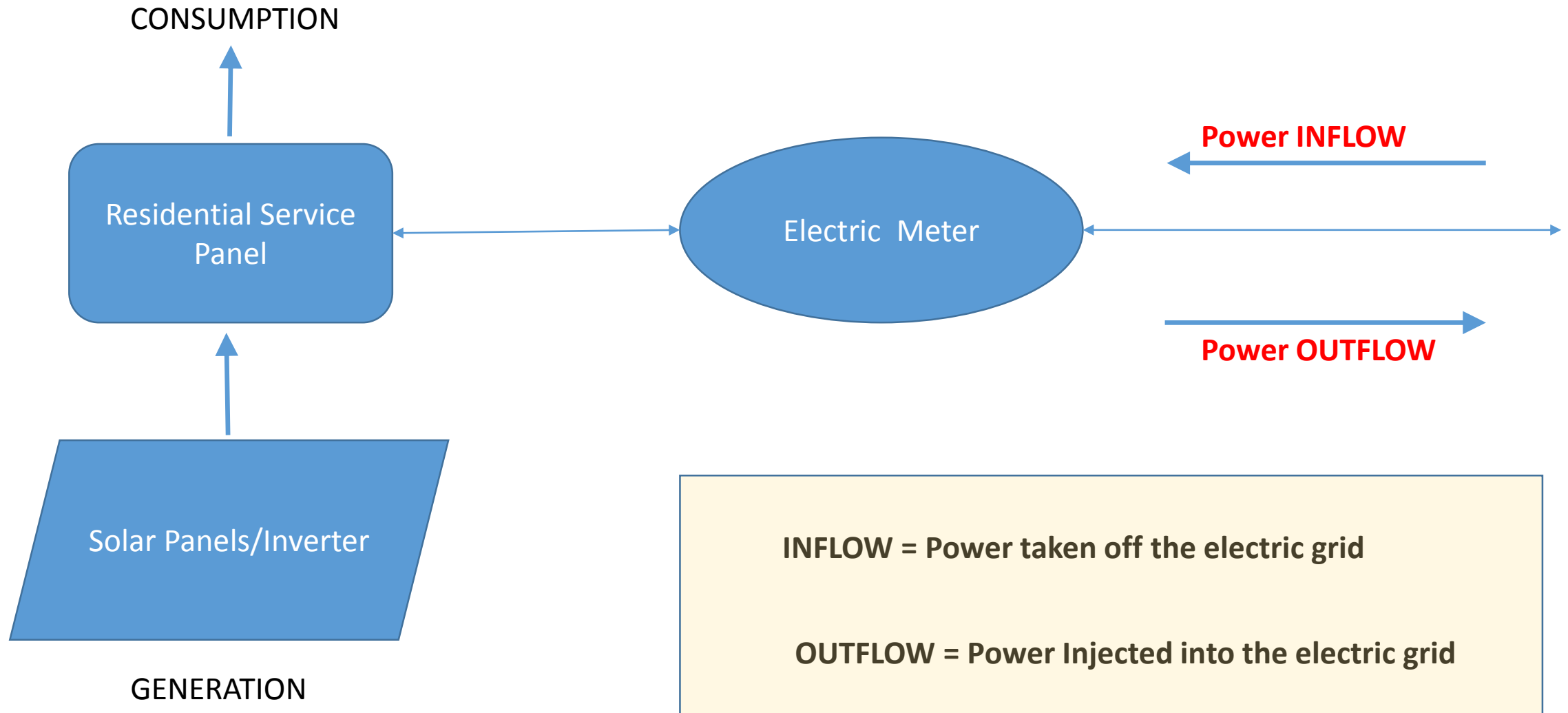
**Core Issue:**



# Solution - Inflow & Outflow Mechanism

- **Supports traditional cost causation analysis**
  - Easiest method to implement *cost-of-service* based rates
  - Allows for dynamic pricing, dynamic credits, value of energy or avoided-cost credits, and demand charges (distribution and power supply)
- **Customer bills are highly correlated with actual power flows** at the customer's interconnection with the distribution grid
  - Can send clear and accurate pricing signals to customers
- **Flexible platform is “future proof”** with respect to changing DG technologies and regulatory objectives

# What is INFLOW and OUTFLOW?



# Inflow & Outflow Pricing Model

[Simple commodity based rate-design]

Uses **Inflow** and **Outflow** to calculate the customer bill:

$$\text{Customer Charge} + (kWh)_{\text{Inflow}} \times \left( \frac{\$}{kWh} \right)_{\text{Full Retail Rate}} - [(kWh)_{\text{Outflow}} \times \left( \frac{\$}{kWh} \right)_{\text{Value of Energy \& Capacity}}]$$

Starting Point: Same Retail Rate as Full Requirements Customers

# Inflow & Outflow Pricing Model

[Commodity and demand based rate-design]

Uses **Inflow** and **Outflow** to calculate the customer bill:

$$\begin{aligned} &\text{Customer Charge} + \\ & (kWh)_{\text{Inflow}} \times \left( \frac{\$}{kWh} \right)_{\text{Distribution \& Power Supply}} + (kW)_{\text{Inflow}} \times \left( \frac{\$}{kW} \right)_{\text{Distribution \& Power Supply}} \\ & - [(kWh)_{\text{Outflow}} \times \left( \frac{\$}{kWh} \right)_{\text{Value of Energy}}] - \text{Capacity Credit}_{\text{Outflow}} \end{aligned}$$

**Based on Outflow, not Nameplate Capacity:**

**e.g.**

$$ELCC \times Capacity_{\text{Nameplate}} \times Outflow_{\text{Capacity Factor}}$$

# I & O Mechanism Requirements

- **Billing meter must be capable of measuring power flows in both directions**
  - Extensive smart-meter data allows for progressively more accurate COSS allocators in future general rate-proceedings
  - Reasonable to base implementation on net-metered hourly demand [i.e. net inflow or net outflow]
- Ideal implementation based on independent calculation of **integrated** inflows and **integrated** outflows
  - On an instantaneous basis, there is only a power inflow or outflow
  - In any given hour a customer can have both inflows and outflows
  - Not the same as net-metered hourly demand
  - Consideration for future fine-tuning of I&O mechanism

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# Model Structure

- Excel Model (hourly)
- Model input – residential consumption & solar PV generation

## **DOE/NREL System Advisor Model (SAM)**

### **Residential Hourly Load Distribution**

[Lansing Capital City Airport TMY3 ]

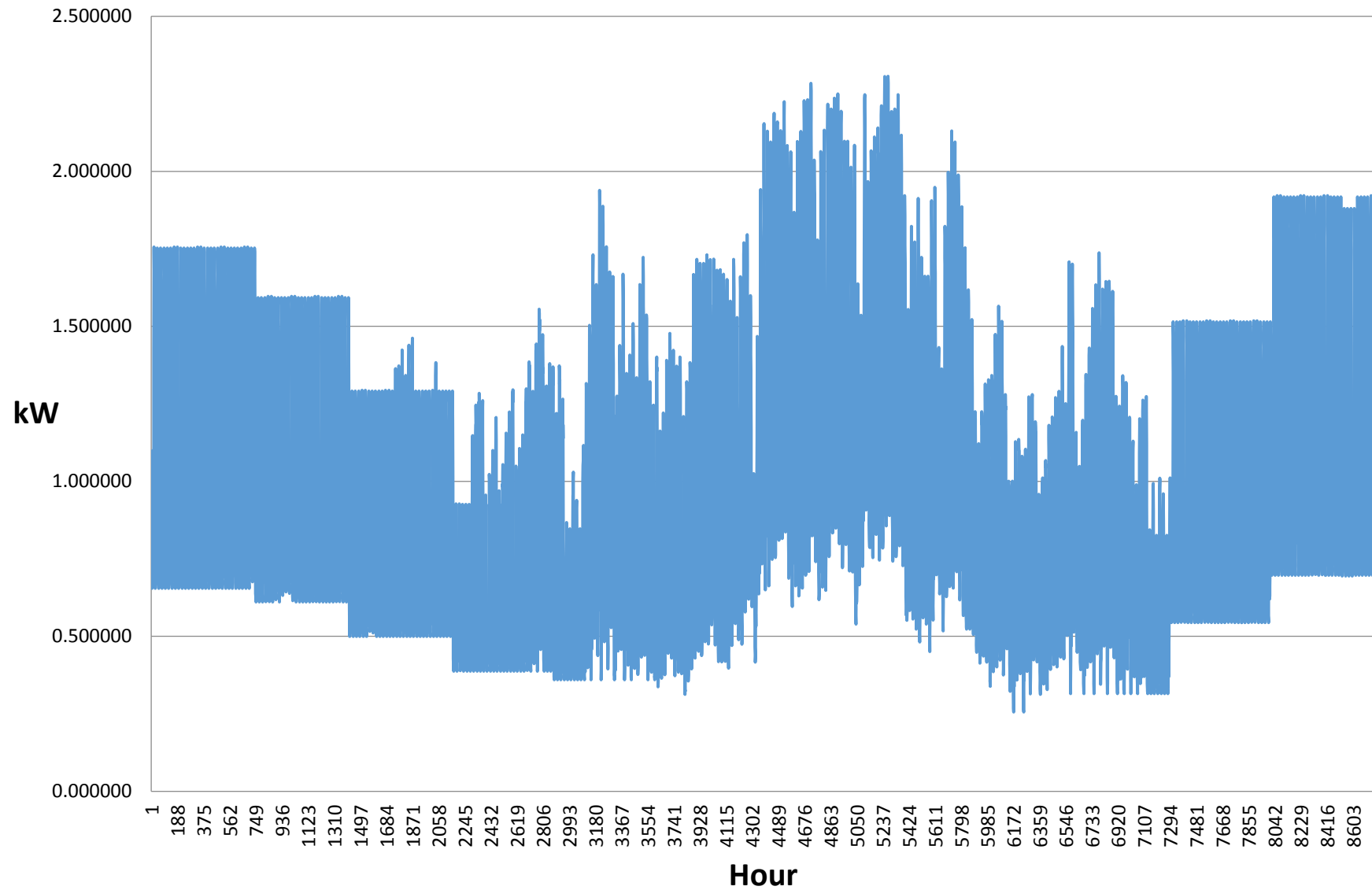
## **NREL PV watts Model**

**(8760 hour) Solar Output kW (AC)**

**Fixed Tilt @ 20deg, Lansing MI**

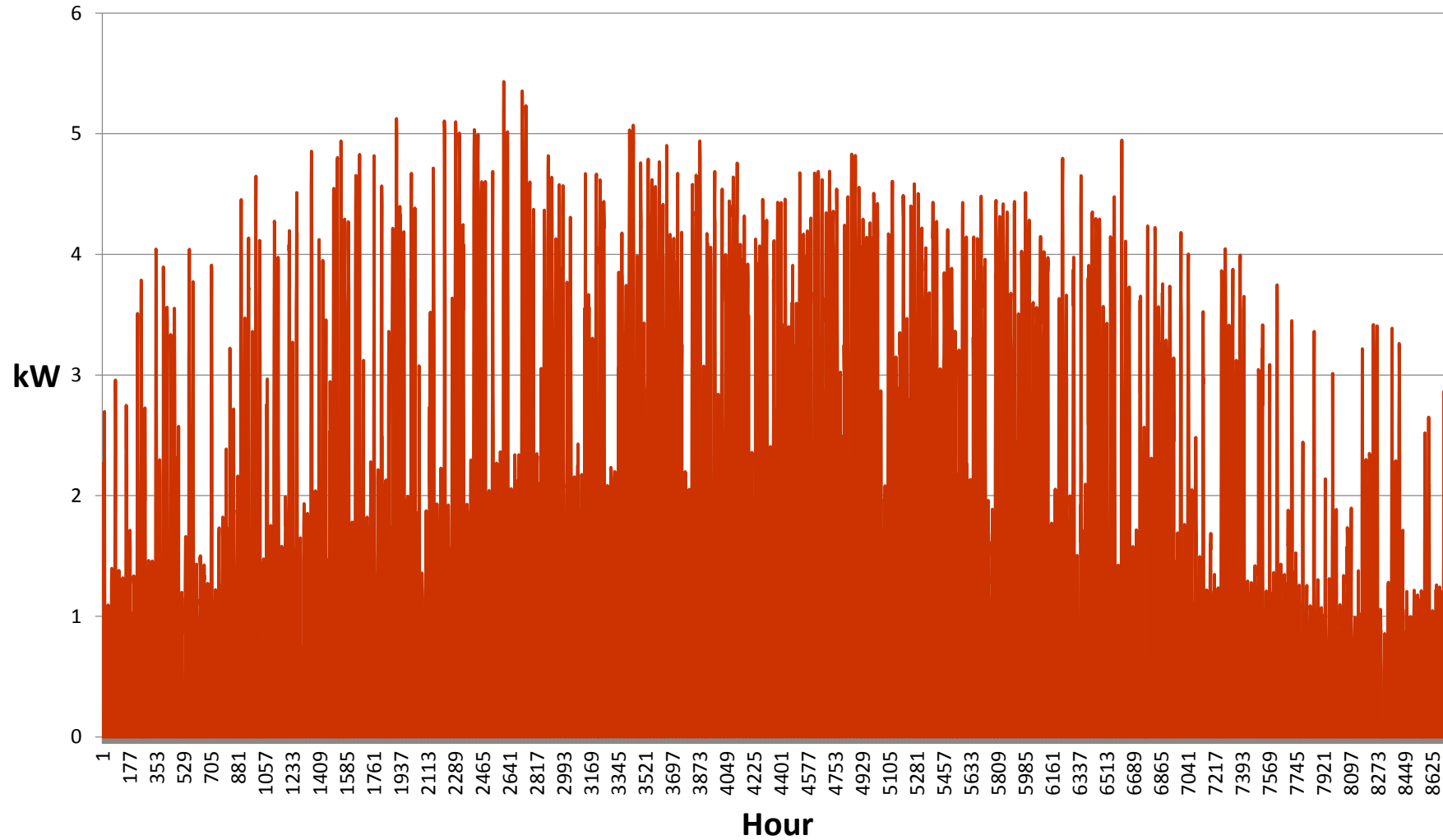
- SAM output calibrated to Consumers Energy's projected 2016 test-year residential annual sales level of 7,844 kWh [U-17990]
- Monthly sales distribution calibrated to match CE's 3-year average residential 4CP (best match uses historical 2010 residential monthly sales distribution)
- **Model Output - power inflow, power outflow, onsite usage, battery charge, and battery discharge**

**Average Residential Usage - Hourly kW/Customer**  
**Annual Load - 7,844 kWh**





**NREL PVWatts Calculator**  
**Hourly Solar Output (AC) kW**  
**System Capacity 6.28 kW (DC)**  
**Fixed Tilt @ 20deg, Lansing MI**



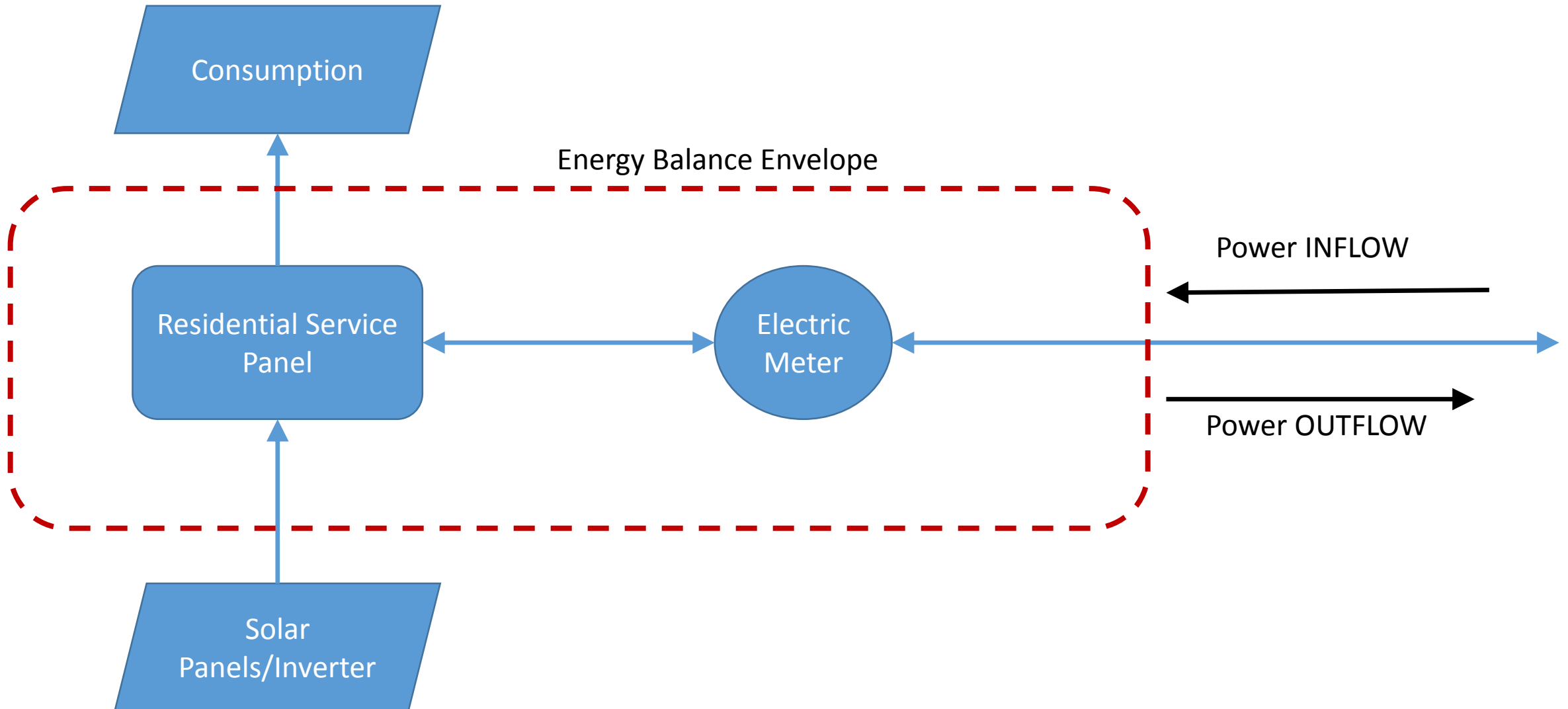
# Modeling Mathematics

- The derivation of the mathematical relationships between generation and consumption, and power inflows and outflows, starts with an energy balance:

$$\text{[Energy In = Energy Out]}$$

**Equation (1)**

# Distributed Generation Customer Energy-Balance



# Energy Balance

- Inserting all energy flows intersecting the energy balance envelope [dashed line] into Equation (1), yields an exact relationship between the model's key input variables, generation and consumption, and the desired grid parameters, inflow and outflow; i.e.

- **[Generation + Inflow = Consumption + Outflow]** **Equation (2)**

- Or alternately stated;

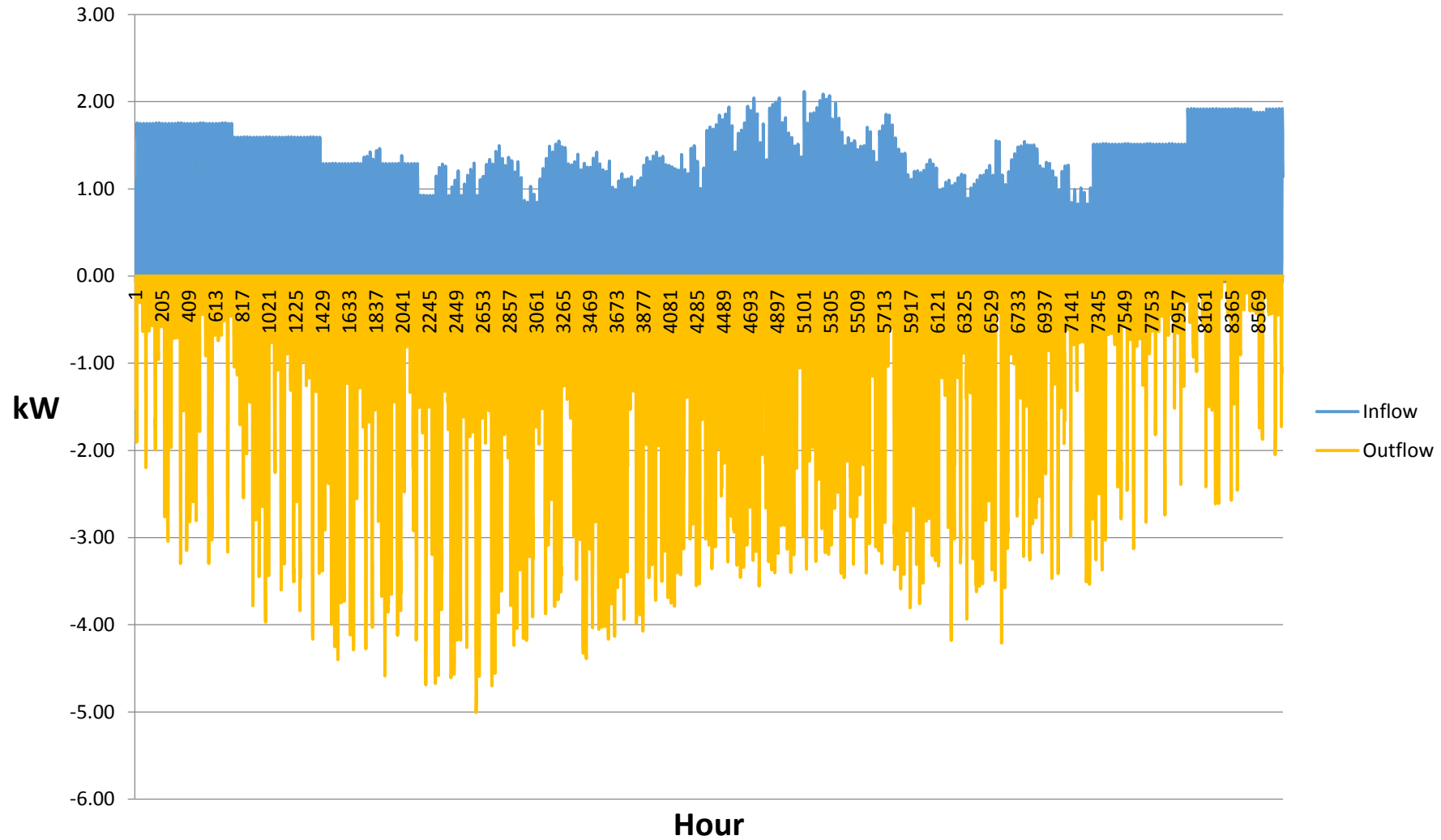
- **[Inflow – Outflow] = [Consumption – Generation]** **Equation (3)**

# Simplifying Assumption

- Consumption and generation data-output by the SAM and PVWatts® models are limited to hourly values.
- A **net positive (or negative)** value of [Consumption – Generation] over the course of an hour represents a practical estimate of the **integrated hourly inflow (or outflow)** for that hour.

In this manner, a stream of 8760 (hourly) inflows and outflows are developed from consumption and generation data.

**Residential Distributed Generation Customer**  
**Hourly Inflow & Outflow (kW)**  
**January -December**  
**Solar PV Capacity 6.28 kW (AC)**



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# Onsite Usage of Distributed Generation

**Because onsite-usage can be quantified by reference to smart-metered power flows, it is the key to unlocking past barriers to implementation of cost-of-service based DG tariffs.**



# Calculation of Generation Used Onsite

Rearranging the energy balance (Eq. 3) yields two identities:

$$\text{[Generation – Outflow]} = \text{[Consumption – Inflow]} \quad \text{Equation (4)}$$

*These mathematical identities are recognized as representing the “onsite-usage” portion of the generation output.*

$$\text{Onsite usage} = \text{[Generation – Outflow]} \quad \text{Equation (5)}$$

And:

$$\text{Onsite usage} = \text{[Consumption – Inflow]} \quad \text{Equation (6)}$$

# Inflow/Outflow as a Function of System Properties

The ***physical electrical system*** suggests that Equations (5) and (6) be rearranged to a form in which inflow and outflow are the dependent variables:

$$\text{Inflow} = [\text{Consumption} - \text{Onsite Usage}]$$

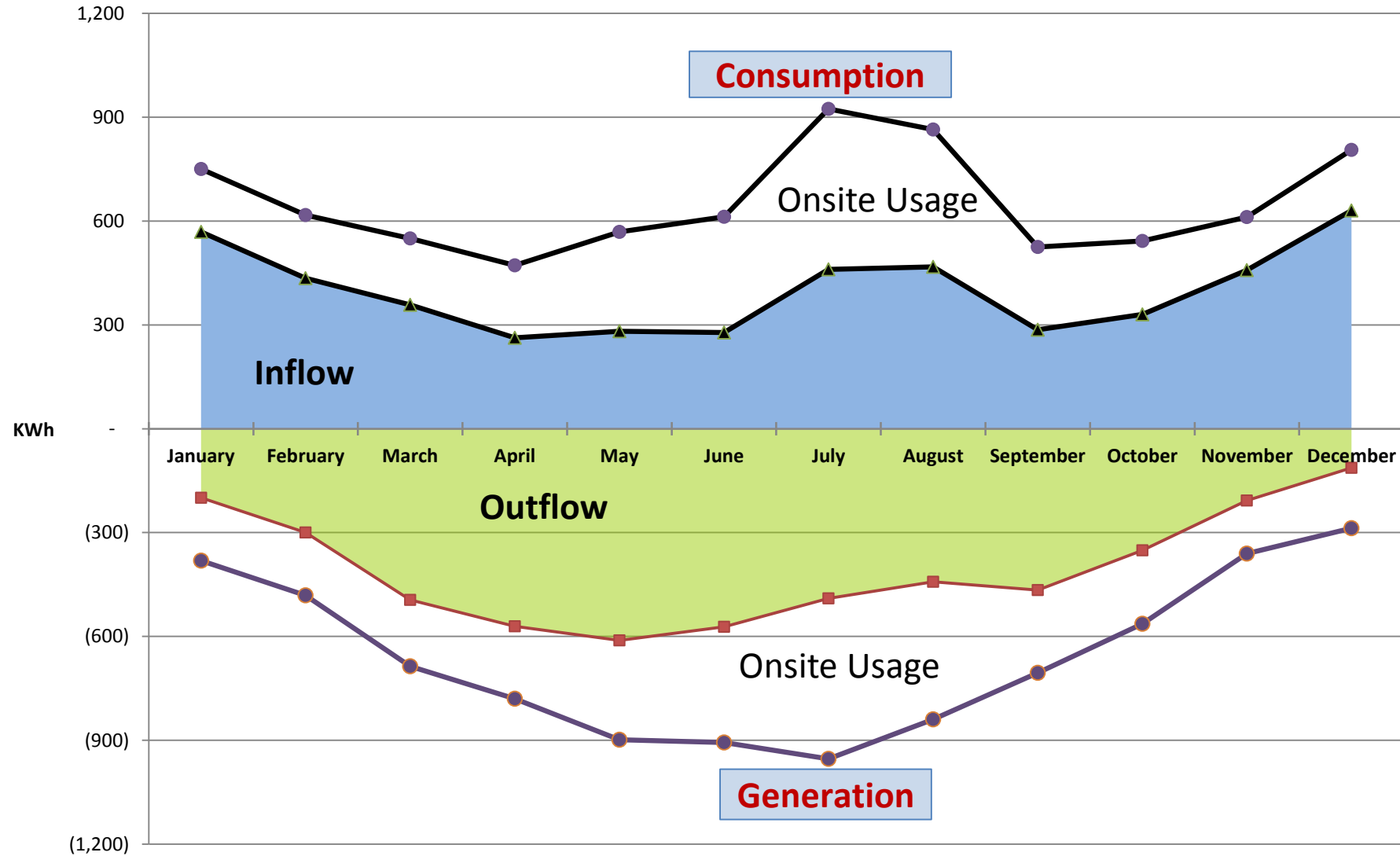
Equation (9)

And:

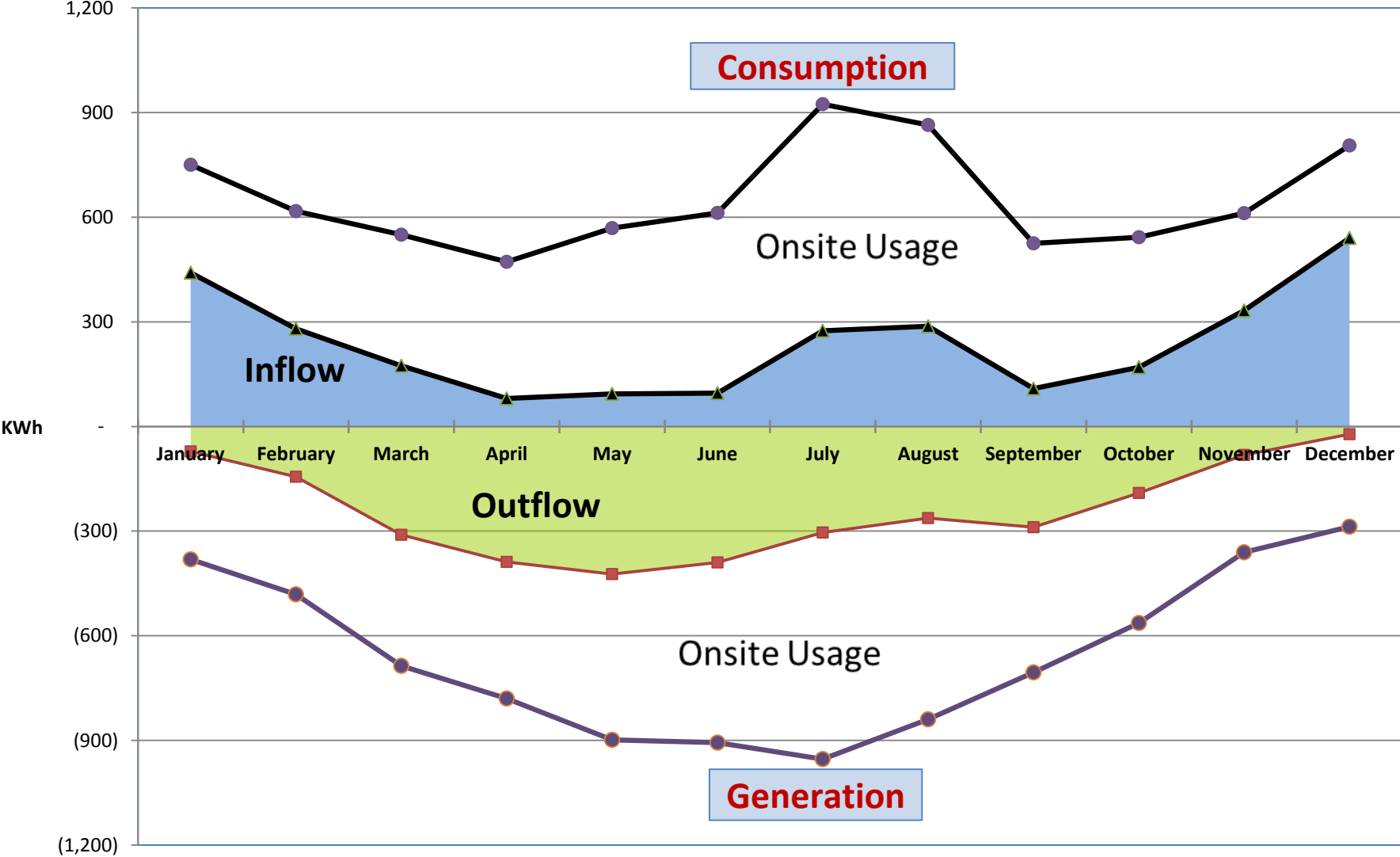
$$\text{Outflow} = [\text{Generation} - \text{Onsite Usage}]$$

Equation (10)

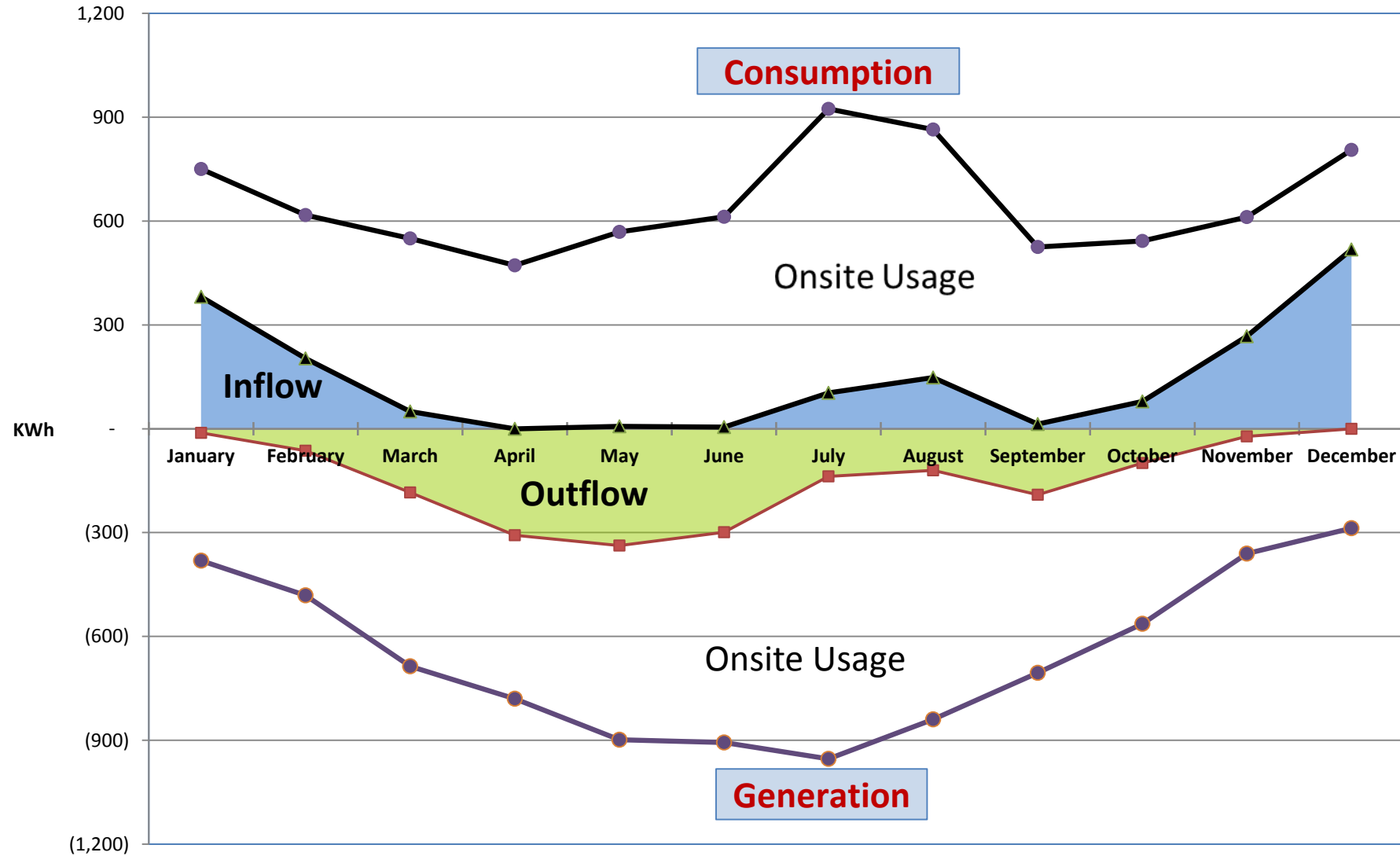
**Residential Distributed Generation**  
**Comparison of Power Flow Parameters**  
6.28 kW Solar PV [100% of Annual Consumption]: 8760 hour analysis



**Residential Distributed Generation**  
**Comparison of Power Flow Parameters**  
6.28 kW Solar PV + 7 kWh Tesla Powerwall 1: 8760 hour analysis



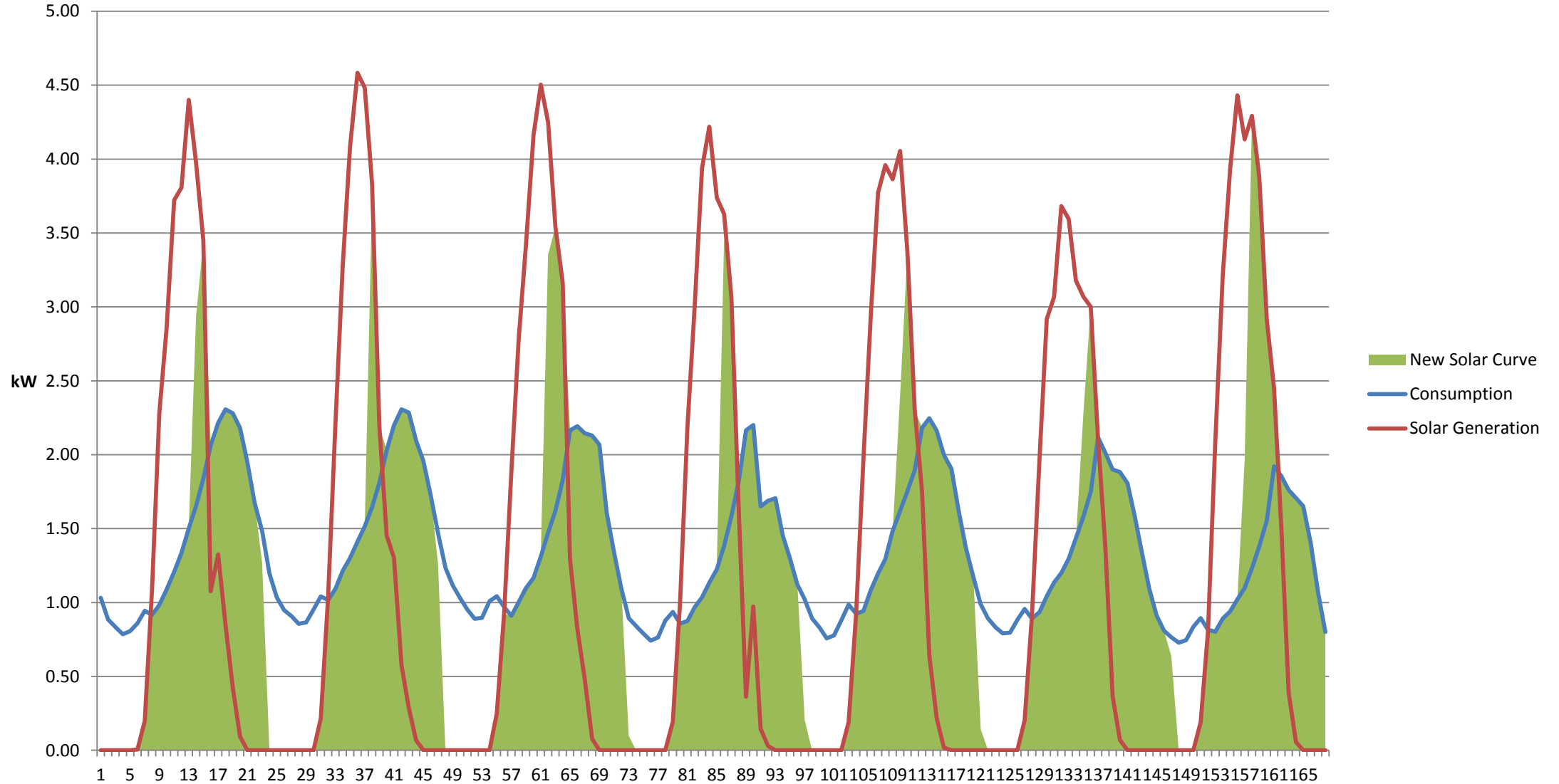
**Residential Distributed Generation**  
**Comparison of Power Flow Parameters**  
6.28 kW Solar PV + 14 kWh Tesla Powerwall 2 : 8760 hour analysis



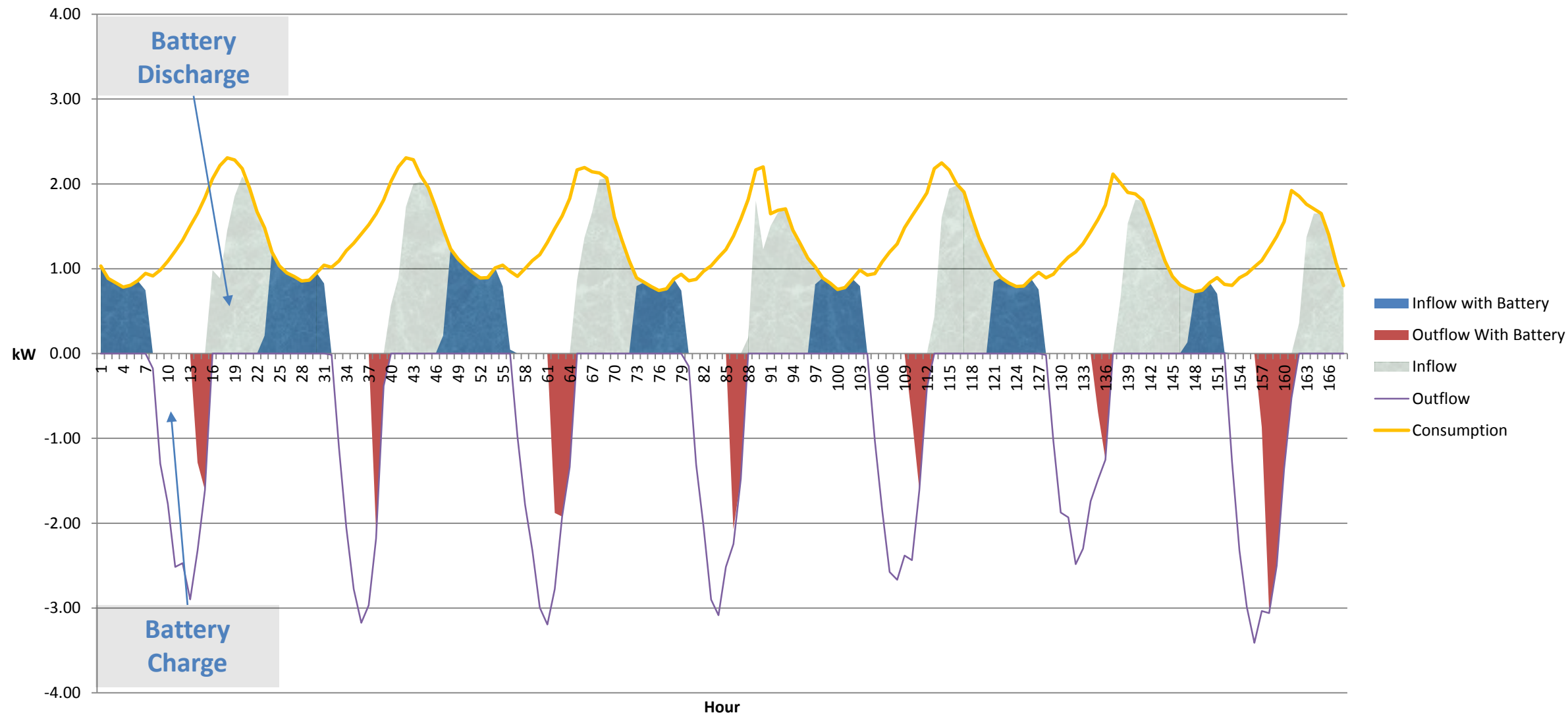
# Time-shifting of Solar Output

August 7-13 [hourly]

6.28 kW (DC) Residential Solar PV + 14 kWh (DC) Tesla Powerwall2



**Residential Hourly Peak-Demand Reduction**  
**August 7-13 (Hourly)**  
**6.28 kW (DC) Residential Solar PV + 14 kWh Tesla Powerwall 2**



## Observations

- **Optimal operation of grid-interconnected DG systems occurs when onsite-usage is maximized [for a given level of PV Capacity]**
  - If the level of generation physically used on-site could be increased, then to that extent, more efficient operation of the DG system is achieved
  - The timing of onsite usage is also a factor leading toward operational efficiency, e.g. peak demand reduction
  - I&O with battery storage mitigates the issue of two-way flows on radial distribution circuits with high penetration of customer sited solar PV

## Conclusions

- **If the economic payback to a customer under a particular regulatory mechanism is indifferent, or nearly indifferent, to changes in the level (and timing) of onsite-usage, then such mechanism is inherently flawed**
  - Net Energy Metering (NEM) is indifferent to changes in the level/timing of generation used onsite
  - Buy-all Sell all (BASA) is indifferent to changes in the level/timing of generation used onsite



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implications of DG study  
results**
6. Economic & payback  
analysis

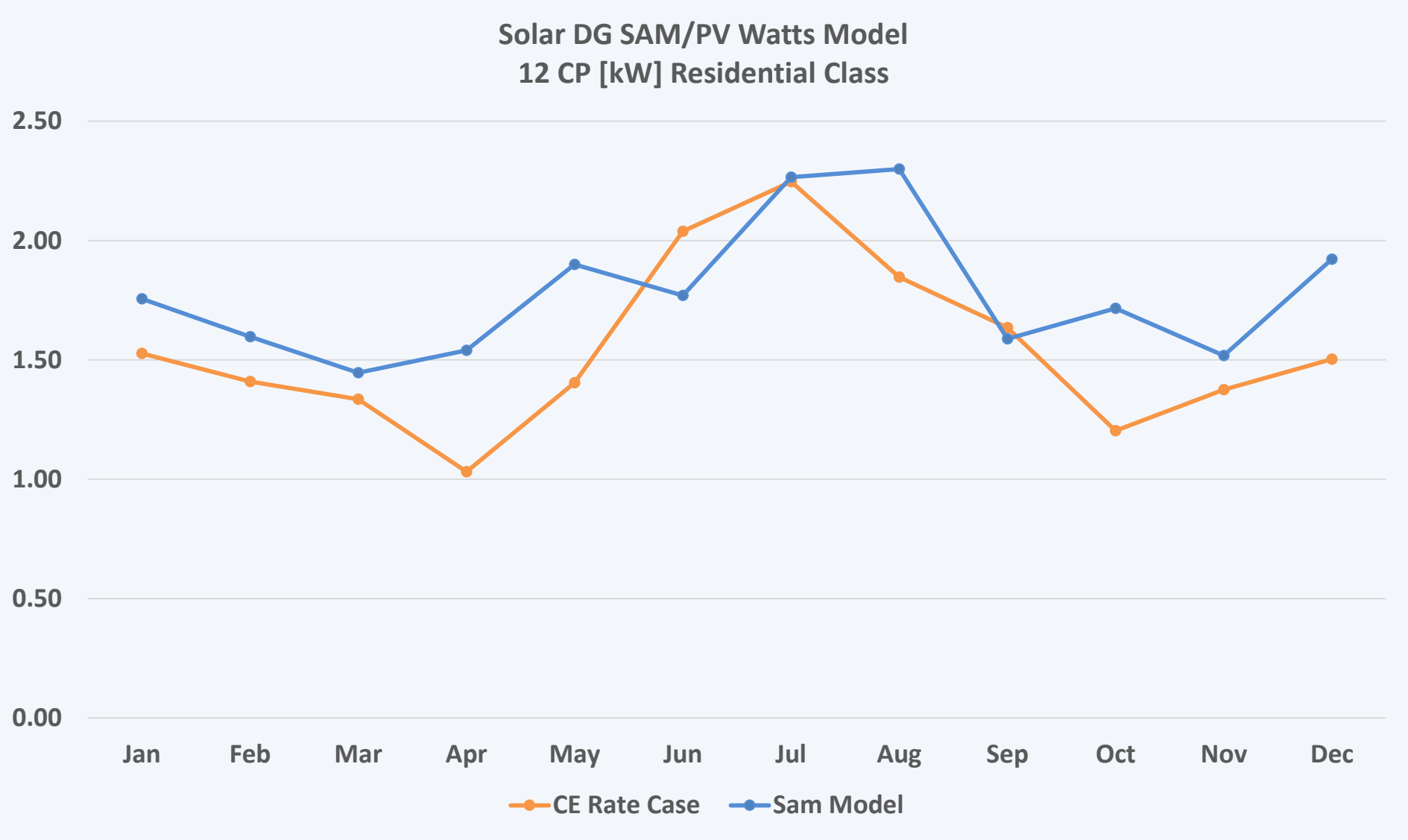


# Findings related to Cost-of-Service

- Load diversity (i.e. power inflows) within the sub-group of residential DG customers can be significant
  - Residential DG peak-demand (inflow) is strongly correlated with the level of solar PV capacity vis-à-vis a customer's annual load
  - Residential DG peak demand can be reduced by onsite energy storage operated to re-dispatch solar output (load following)

# Good Correlation between Model and Rate Case Coincident Peaks

(Consumers Energy U-17990)

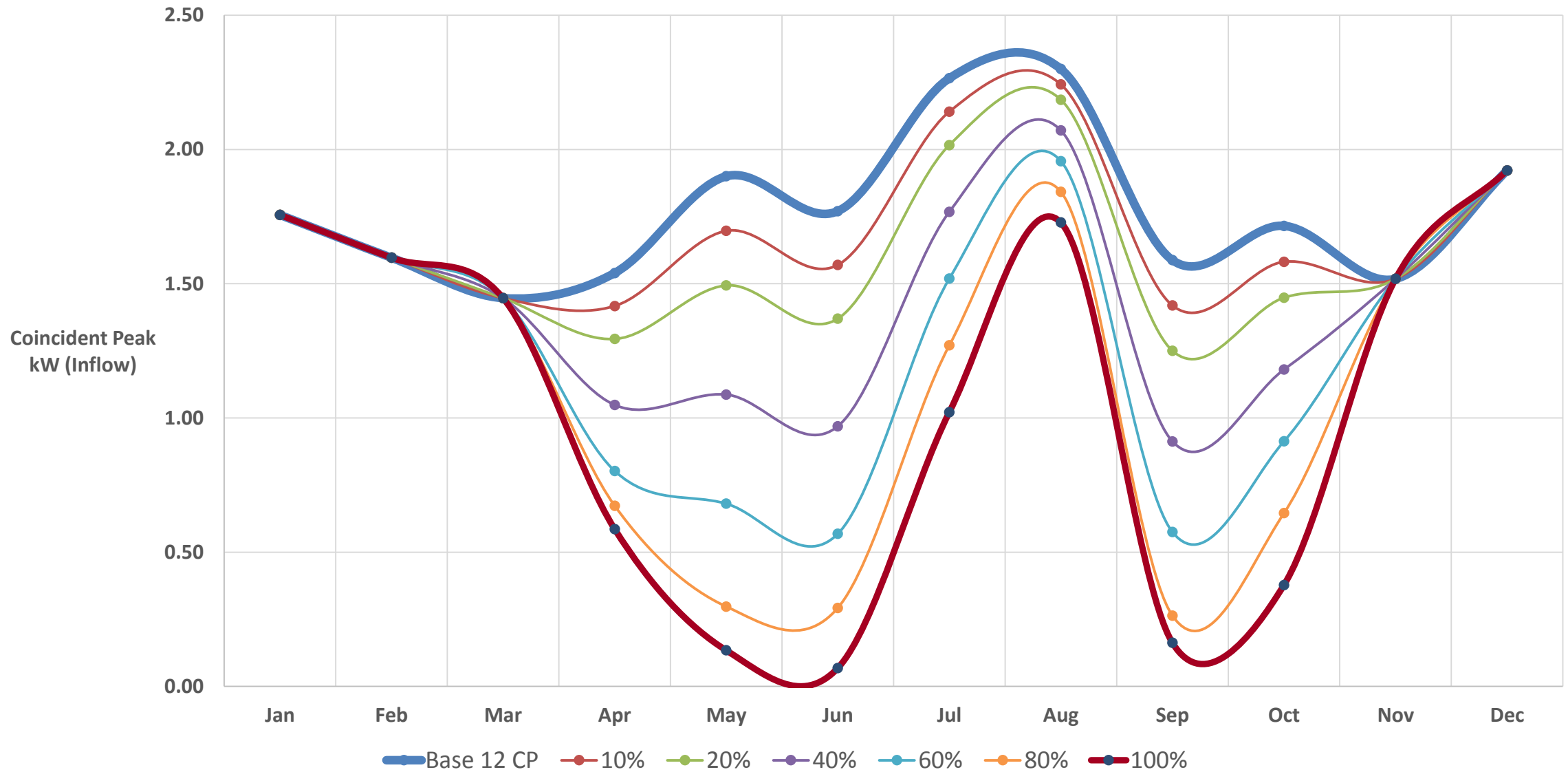


# Comparison of 8760 Hour Model To Approved Residential 4CP [CE U-17990] Solar PV System Capacity [100% of Annual Consumption]

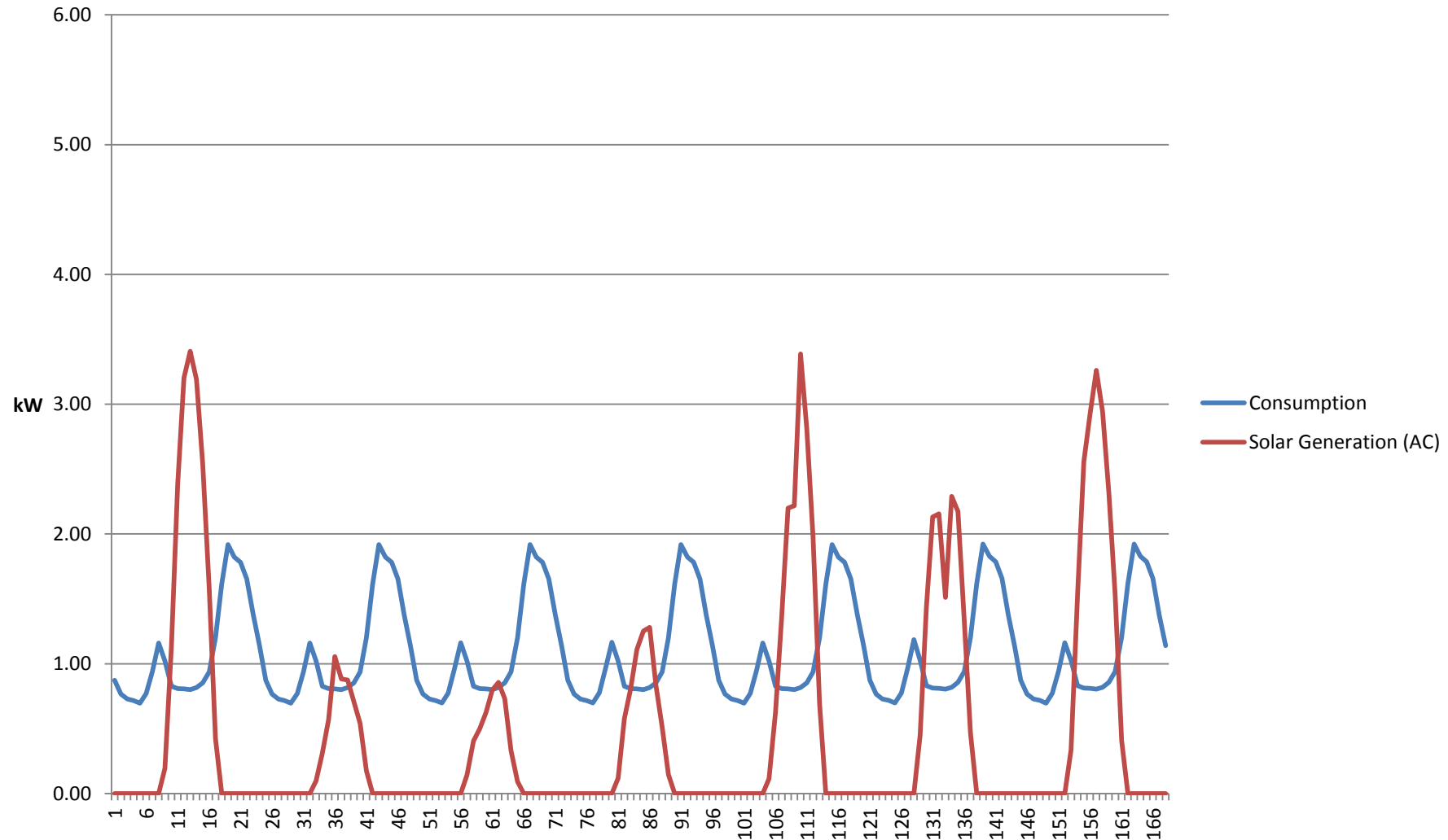
CE Rate Case U-17990		Model Solar DG	
4 CP	Residential RS +RT kW/Cust	Residential kW/Cust	Inflow kW/Cust
Jun	2.04	1.77	0.07
Jul	2.25	2.27	1.02
Aug	1.85	2.30	1.73
Sep	1.64	1.59	0.16
Total	7.8	7.9	3.0

With  
Solar PV

Residential Monthly Coincident Peak  
As a Function of  
Solar PV Output as a % of Annual Consumption



**Residential Distributed Generation Customer  
Consumption and Generation  
December 11 - 17 [hourly]  
6.28 kw (AC) Solar PV [100% of Annual Consumption]**



# Modeling Observations and Conclusion Regarding the COSS Segregation of Solar DG Customers

- Customers having **small to moderate levels** of PV capacity (relative to their annual consumption) have monthly **peak-demand profiles** that are similar to the full requirements customers
  - Like a smaller-than-average customer
- Customers having **high levels of PV capacity** have lower summer coincident peaks – but nearly identical winter peaks as full requirements customers

Net Zero DG



Energy	61.4%
4CP	38.0%
12CP	57.8%

**Conclusion: COSS segregation of solar PV DG customers into a separate rate-class may not be necessary as inflow as a billing determinant (rate design) will allocate a proportionately reduced cost to DG customers (energy & 12CP, ~1/2 4CP)**

# Outline

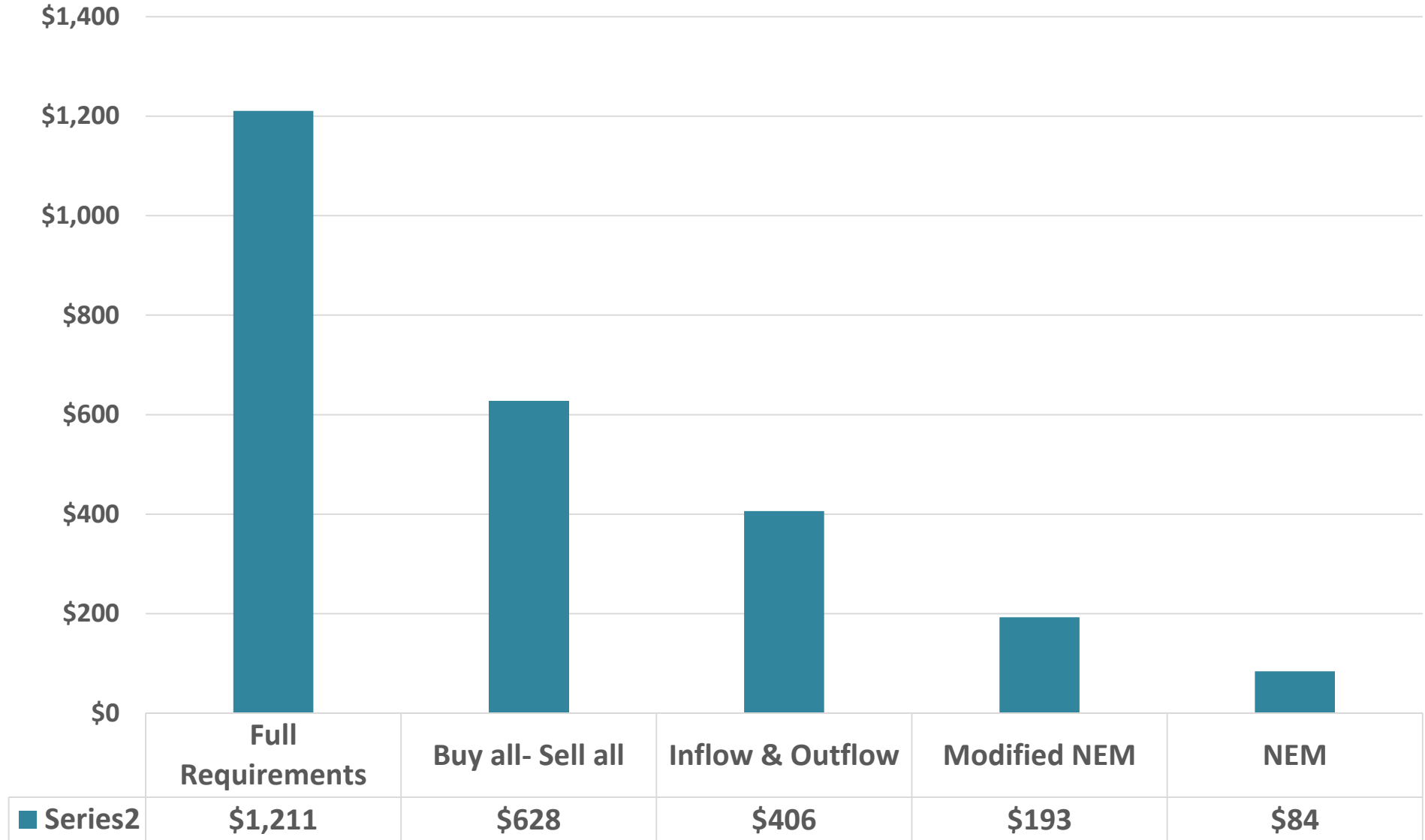
1. Introduction
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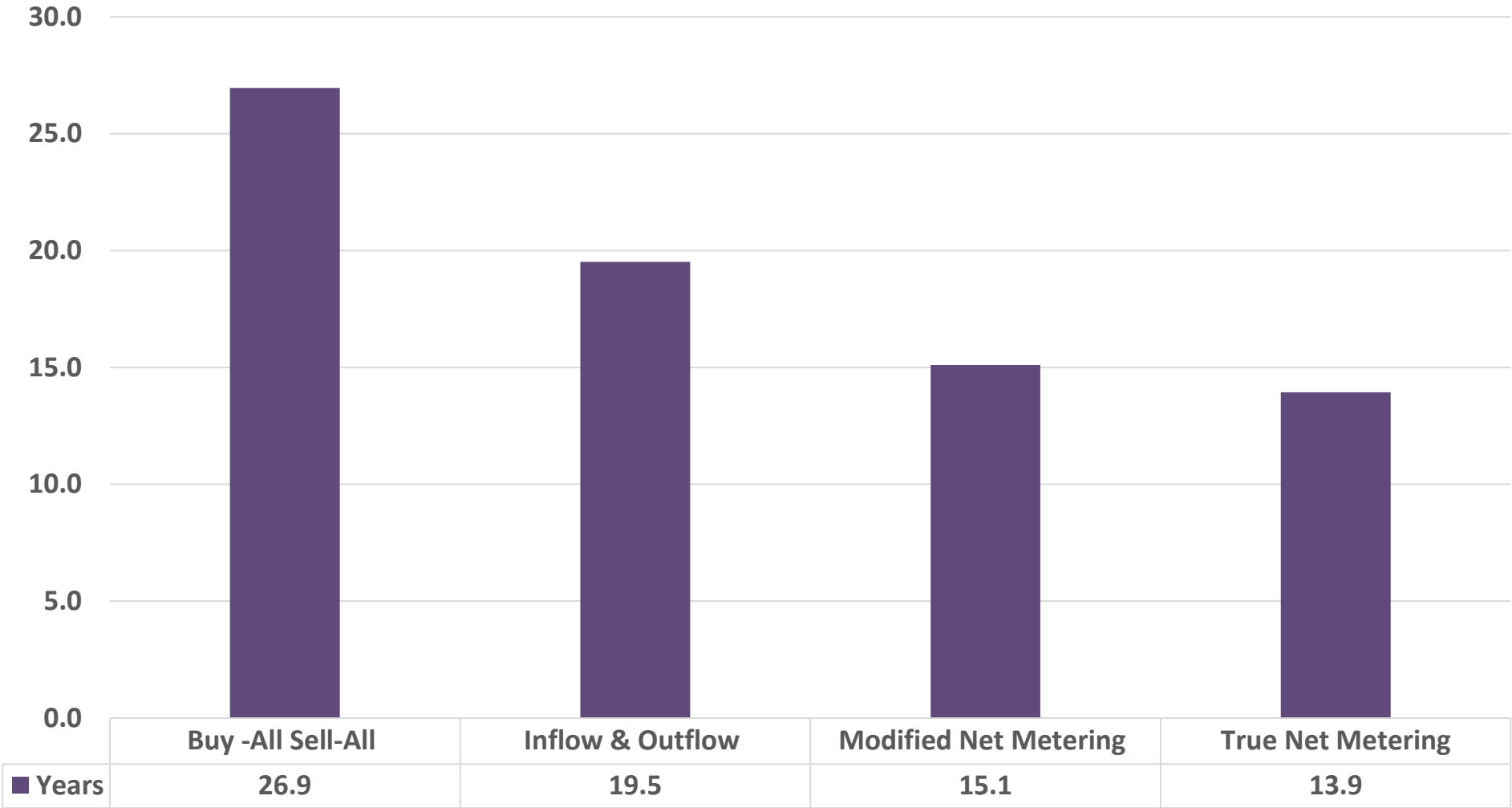


Residential Annual Bill

**Standard Pricing**; Generation Valuation @ 7.43 cents per kWh  
6.28 kW Solar PV @ 100% of Annual Consumption



Simple Payback  
Installed Cost \$15,700 \$2.50/Watt (Excludes ITC)  
6.28 kW Solar PV [100% of Annual Consumption]  
Standard Residential Rate/7.43 cents/kWh Credit



# Valuation of Solar PV Outflow

## Effective Outflow Capacity Method

6.28 kW (AC) Solar PV [100% of Annual Purchases]	7,844 kWh
Credit -LMP Monthly Average MISO REAL TIME	0.035
Energy Loss Factor	0.079
Value of Energy \$/kWh	0.038002172
Cost of New Entry (CONE) \$/kW-yr	\$ 94.80
100% of CONE \$/kW-Yr	\$ 94.80
Nameplate Capacity kW (DC)	6.28
Outflow Capacity factor [Outflow/Generation]	61.4%
Effective Load Carrying Capacity (ELCC)	44%
Effective Capacity kW (AC)	1.70
Capacity Credit - \$/Yr	\$160.93
Capacity Loss Factor	0.079
<b>Capacity Credit [ \$/Yr]</b>	<b>\$ 174.74</b>
Annual Outflow kWh	4818
Capacity Value \$/kWh	\$ 0.036
<b>Value of Generation \$/kWh</b>	<b>\$ 0.0743</b>

1.26 kW Solar PV [20% of Annual Purchases]	1,569 kWh
Credit -LMP Monthly Average MISO REAL TIME	0.035
Energy Loss Factor	0.079
Value of Energy \$/kWh	0.038002172
Cost of New Entry (CONE) \$/kW-yr	\$ 94.80
100% of CONE \$/kW-Yr	\$ 94.80
Nameplate Capacity kW (DC)	1.26
Outflow Capacity Factor [Outflow/Generation]	6.5%
Effective Load Carring Capacity (ELCC)	44%
Effective Capacity kW (AC)	0.04
Capacity Credit - \$/Yr	\$3.39
Capacity Loss Factor	0.079
<b>Capacity Credit [\$ /Yr]</b>	<b>\$ 3.68</b>
Annual Outflow kWh	101
Capacity Value \$/kWh	\$ 0.036
<b>Value of Generation \$/kWh</b>	<b>\$ 0.0743</b>

# Conclusions and Recommendations

1. The Inflow & Outflow Mechanism should be adopted as the replacement mechanism for NEM as it provides the best option for achieving:
  1. Clear and accurate pricing signals encouraging optimal operation of DG systems and rational economic behavior of customers
  2. Retail rates based on Cost-of-Service (COS)
2. Modeling suggests that **initial** deployment of the I&O mechanism can have **combined COSS allocations** with the underlying full requirements tariffs [i.e. no separate DG rate classes].
  1. *The rate design itself does much of the cost allocation.*
  2. Better accuracy can be achieved by including a credit to offset to the underlying retail rate
3. **Dynamic pricing** provides enhanced transparency of price signals and thus could be required as a condition for customer enrollment in any future I&O tariff.
4. The feasibility of *load control* and *energy waste reduction* program **incentives** should be investigated as a tool to further develop this energy resource.
5. Outflow credits should be based on the *effective outflow-capacity method* or the Commission's approved PURPA rate (proxy generation method); [standard rate for all program participants].
6. Tariffs should be **simple** and readily understandable.

# Thank You!

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LinkedIn	<a href="https://www.linkedin.com/in/robert-ozar-46224a78">https://www.linkedin.com/in/robert-ozar-46224a78</a>

## **Appendix E: A Background on Value of Solar and its Relation to DG Compensation for Generation Outflows**

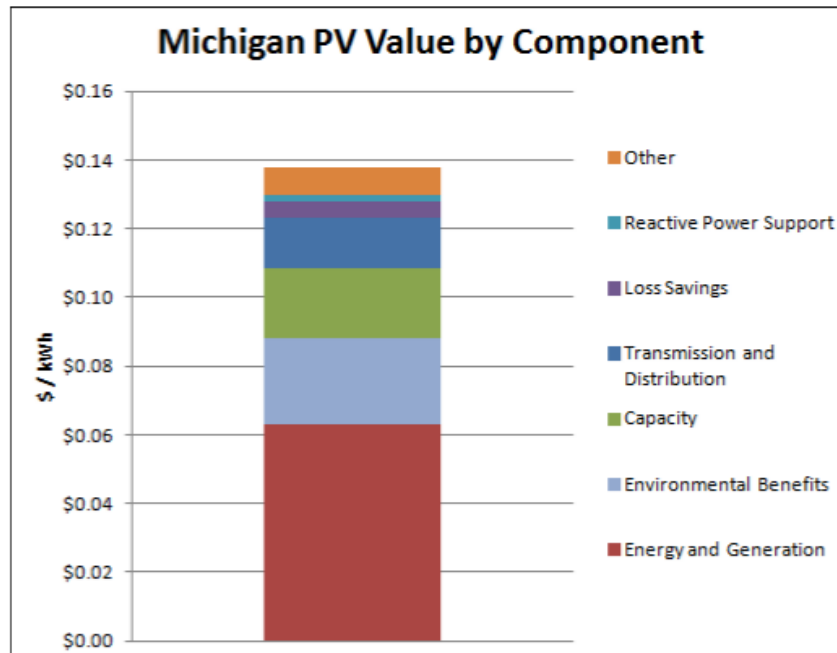
Value of Solar (VOS) has become a popular discussion in last few years with many States looking at updating net energy metering provisions. VOS is a concept that attempts to monetize the benefit of grid connected solar (PV). VOS generally includes the following components:

- **Energy and Capacity** – The generation from grid connected solar offsets the need for the electric utility to generate electricity itself, thus avoiding fuel, maintenance, and potentially capital cost in the form of capacity expansions. It also provides a capacity value during peak load periods when energy and capacity prices are at their highest in the market.
- **Transmission and Distribution** – Since PV is generally distributed throughout the grid, it reduces the need for expanding the transmission and distribution infrastructure as the electrons from the PV that are not used on-site will flow to the closest demand in the area.
- **Transmission and Distribution Loss Savings** – The farther electricity has to travel, the more losses accumulate through heat and efficiency losses. Distributed PV mitigates these losses.
- **Reactive Power Support** – PV inverters have the ability to provide reactive power (VARs) reducing the utility's need to install power supply equipment.
- **Environmental Benefits** – Possibly the hardest and most contested component to monetize, PV can reduce the need for generation from fossil fueled plants which reduces carbon, particulate matter, NO<sub>x</sub>, SO<sub>x</sub> and other health and environmental hazards.
- **Other** – PV has little to no ongoing operating costs so it provides a hedge value against increased future fuel costs.

Michigan began investigating VOS concepts at the end of 2013 when the Commission directed Staff to convene a Solar Working Group (SWG) to discuss improvements to DTE Electric Company's customer-owned *SolarCurrents* Program. The SWG was further expanded to include Consumers Energy Company and various industry and interest groups.

Staff filed a final report on June 30, 2014 in DTE Electric Company's Docket No. U-17302 and Consumers Energy Company Docket No. U-17301. The report provided an overview of the various VOS calculation methodologies that ranged from DTE Electric Company's 3.9 cents per kWh to the National Renewable Energy Laboratory Michigan-

specific VOS calculation<sup>12</sup> of 13.8 cents per kWh (NREL calculation is from a draft analysis and provided as an example only.).



In May of 2015 the Commission reconvened the SWG with the intent of determining a just and reasonable value of capacity in the VOS computation with respect to Consumers Energy Company's Solar Gardens Program. Considerations for this capacity value were the Midcontinent Independent System Operator (MISO) Annual Planning Reserve Auction, MISO Cost of New Entry (CONE), Utility embedded costs, and stand-by capacity costs. Staff filed its report on September 30, 2015 in Consumers Energy Company's Docket number U-17752 which detailed the Company's updated Solar Gardens program that included a capacity payment equal to 75% of MISO CONE.

In October of 2015 the Commission directed Staff to form a Technical Advisory Committee (TAC) to consider the appropriate implementation of the Public Utilities

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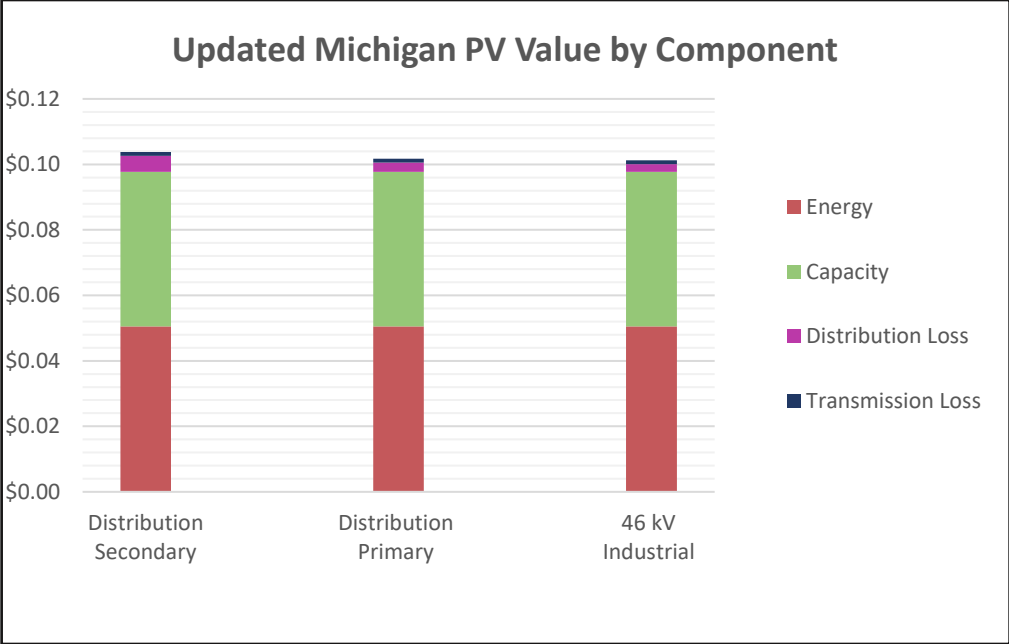
<sup>12</sup> NREL White Paper: The Value of Grid-Connected Photovoltaics in Michigan (Michigan Review Draft 1/23/2012): Sean Ong - [http://www.michigan.gov/documents/mpsc/120123\\_PVvaluation\\_MI\\_394661\\_7.pdf](http://www.michigan.gov/documents/mpsc/120123_PVvaluation_MI_394661_7.pdf)

Regulatory Policies Act of 1978. Staff issued a report on the TACs finding on April 8, 2016. In this Report Staff presented a methodology for determining the avoided cost which utilized a modified proxy plant methodology which valued capacity at the cost of a new natural gas combustion turbine plant and energy at the MISO locational marginal price or based on the variable costs of a natural gas combined cycle plant. On May 3, 2016 the Commission issued an Order initiating avoided cost proceeding for all investor owned utilities in Michigan.

Intervenors to the avoided cost cases argued that PURPA allows for the consideration of factors in addition to capacity, energy and line loss values, such as hedge value, reduced air emissions and environmental compliance cost. The Commission agreed and stated that once quantified, these costs should be included in the calculation of avoided cost which includes many of the components discusses above in a VOS calculation.

As discussed above, NREL's Draft White Paper was released in the early part of 2012. Since then, many aspects of the calculation are now outdated. Using updated energy and capacity data from the Consumers Energy Company's avoided cost Case No. U-18090, an updated VOS calculation is around 10 cents per kWh. This calculation includes a levelized capacity value of approximately 4.7 cents per kWh and a 20-year levelized energy value of approximately 5.1 cents per kWh. A 2.37% transmission loss factor is added to the energy value. When factoring in a distribution line loss value ranging from 4.63% to 9.74% for energy based on the Company's Line Loss Study, it accounts for an additional 0.0023 cents to 0.005 cents for energy (the line loss value was not included in the Company's avoided cost case and only presented here to calculate an updated VOS estimate). The calculation results for several distribution voltages are shown below. When compared to the NREL Draft White Paper, Staff did not include reactive power support, or additional environmental benefits as these values are difficult to monetize and Michigan currently does not have peer reviewed data or legal precedent to include these calculations. Going forward, Staff hopes to calculate these components in future biennial avoided cost cases.





## Appendix F: Distributed Generation Activities in other States

During the November 7, 2017 DG Workgroup meeting Tom Beach of Crossborder

Energy on behalf of Vote Solar gave a presentation titled “Evaluating Net Metering.”

The presentation included a slide showing some other states with Inflow/Outflow billing mechanisms.<sup>11</sup>

### States with Some Form of Inflow/Outflow

- AZ, CA, HI, NH, and NV
  - All have significant solar penetration.
  - All used standard NEM until DG was well-established.
  - Inflow and outflow rates are similar, except in HI.

State	Netting	Inflow Rate	Outflow Rate
AZ	Instantaneous	Retail TOU rate, plus small fixed Grid Access charge	Utility-scale solar costs plus T&D. Similar to retail now, -10% per year.
CA	Hourly (residential)	Retail TOU rate, with a \$10/month minimum bill.	Retail rate minus public purpose program costs (< 10% of rate)
NH	Monthly	Retail rate (flat or TOU)	Retail rate minus 75% of distribution costs (~3 c/kWh).
NV	Monthly	Retail rate (flat or TOU)	95% of retail, declines 7% for every 80 MW of new DG.

- HI is a special case, “a postcard from the future”
  - 15% - 20% of customers have solar
  - Self-supply only, working on a “smart export” rate

Crossborder Energy

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<sup>11</sup> [http://www.michigan.gov/documents/mpsc/Observations\\_on\\_Evaluating\\_Net\\_Metering\\_in\\_Michigan\\_-\\_v2\\_2\\_603866\\_7.pdf](http://www.michigan.gov/documents/mpsc/Observations_on_Evaluating_Net_Metering_in_Michigan_-_v2_2_603866_7.pdf)

## California

California has updated its net metering program with the Net Energy Metering Successor Tariff; generally referred to as NEM 2.0. The main driver behind the update was the concern that NEM customers were not contributing their fair share to public programs funded through a portion of electric rates, thus placing an unfair cost burden on non-solar customers. An increase in renewables on the grid also contributed to a need for an updated program.

An important change to the NEM program is the increase in the cap of aggregate customer demand. The previous NEM program had a cap of 5%. NEM 2.0 has extended the program to a cap of 7.5% of aggregate customer demand, or until 2019. This change allows more customers to enroll in the program.

Another notable difference in the NEM 2.0 program is the addition of non-bypassable charges (NBCs). The NBCs reduce the value of electricity exported to the grid and separates this component into a category that cannot be offset by future energy credits. The NBC is \$0.02 - \$0.03/kWh and helps to maintain revenue for existing programs. These charges are not a new component of the utility rate. The change is in the way they are handled for NEM 2.0 customers; and all customers must pay for current programs as part of their electricity bill.

Customers of the new NEM 2.0 program must enroll in a time-of-use (TOU) rate. This change is designed to align electricity costs with demand across the grid. On-peak and off-peak pricing will apply to both consumption and generation. The new NEM program prohibits many fixed charges for residential customers, including demand charges, grid access charges, installed capacity fees, and standby fees.

NEM 2.0 does not have a maximum generator size for customers, provided the system is only sized up to the customer's annual load. For systems up to 1MW, a one-time interconnection fee is required to connect to the electric grid. This fee varies between \$75 and \$150 depending on the incumbent utility and system type. Systems

greater than 1MW are subject to full Rule 21 interconnection and facilities upgrade costs.

Under NEM 2.0, participating customers receive a bill credit for excess generation exported to the grid. Excess generation credits are applied monthly to a NEM customer's bill at the same retail rate that the customer would have paid for energy consumption according to their applicable rate structure. After 12 months, any surplus energy is compensated at a fair market value which is based on a 12-month average of the market rate for energy. Customers can also receive compensation for renewable energy credits (RECs) produced through their excess generation. Customers must register their system and follow eligibility guidelines in order to benefit from REC compensation.

### Nevada

Nevada has also made significant changes to its net metering program. In June of 2017, legislators passed a bill to revive the state's rooftop solar market. Customers with net metering systems of not more than 25 kW will fall under a rate structure set by the Nevada Legislature. The tiered rate structure is set up to decrease by 7% increments over time as the amount of rooftop solar generation reaches 80 MW benchmarks. There is a floor of 75% of the retail rate as the final tier. As NEM customers earn credits for producing excess energy, the credits will be applied to the next billing period in which consumption is greater than generation.

In Rate Tier 1, customers are compensated at 95% of the retail rate for excess generation. Rate Tier 1 is open until participation reaches 80 MW. At Rate Tier 2, compensation drops to 88% of the retail rate. After 80 MW participation is reached in the second rate tier, Rate Tier 3 will compensate customers at 81% of the retail rate. When Rate Tier 3 has achieved 80 MW of participation, Rate Tier 4 will become available. Rate Tier 4 offers excess generation compensation at 75% of the retail rate. Customers may remain in their Rate Tier, with their compensation rate locked in, for 20 years.

Nevada net metering customers remain in the same customer class as non-net metering customers. There are no penalty charges or fees associated with the NEM

program. NEM customers cannot be subjected to any fee or charge that is different from a non-NEM customer. There is also protection for NEM customers should Nevada move to a deregulated electricity market.

### Other States

Many other states have updated their net metering programs as recently as 2017. Several states, such as North Carolina, Montana, Maine, North Dakota, and Vermont, do not have an aggregate cap on NEM customers. This is in contrast to other states that have set aggregate caps at small percentages of peak load. Indiana has an aggregate cap of 1% of summer peak load for its NEM program. The state of Illinois sets its cap at 5% of the previous year's total peak demand. Louisiana has a very limited cap of 0.5% of retail peak load per utility; while Utah instated a sizable cap of 20% of 2007 peak demand.

The maximum capacity for individual systems also varies widely by state. Rhode Island, for example, has a maximum of 10 MW. States such as Indiana, North Carolina, and the District of Columbia all have maximum capacities of 1MW. Several other states set maximum capacities in the range of 25-50 kW. Maine has different capacity maximums based on whether a customer has an IOU or a COU. Maximum capacity size may vary by utility within a state, as well.

States have varied methods for how they address net energy generated (NEG). Most states have compensation programs where NEG is credited on the next monthly electric bill. North Carolina, Pennsylvania, and DC all offer a NEG credit at the utility's full retail rate. Rhode Island also uses the utility's full retail, less a small fee. North Dakota and Louisiana credit NEG at the avoided cost of the utility. At the end of the 12-month billing year, different states have different approaches to the NEG. In Utah, NEG expires at the end of the year. Utilities are granted NEG with no customer compensation at the end of the year in North Carolina, Maine, and Vermont. In Virginia, customers can choose to carry forward NEG at the end of the year, or sell NEG to the utility.

States have also addressed other issues related to net metering. There are different methods of dealing with interconnection, such as prior agreements, and

governing rules. Some states have instituted minimum bill charges for net metering customers, while others have stand-by rates and charges. Many states have addressed topics such as virtual net metering and community net metering in their net metering programs. Many other states have also addressed REC ownership related to NEG. While not every state has addressed every net metering issue, we will continue to monitor programs in other states as we develop our DG Program in Michigan.