Massachusetts Net Metering and Solar Task Force

Task 5 - Review of Minimum Bill Policies in Other Jurisdictions and Modeling of a Potential Massachusetts Minimum Bill

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1 Executive Summary

A utility minimum bill policy was proposed in 2014 as part of a legislative package to modify the current Massachusetts net metering policy. Minimum bills have been implemented in a number of U.S. jurisdictions as a mechanism to recover costs from utility customers with either low monthly consumption or onsite generation. These mechanisms have been designed to ensure a minimum customer contribution from all ratepayers and to reduce the potential impacts of customer cross-subsidization. Minimum bills differ from other bill mechanisms such as customer charges and demand charges in that they are designed to only impact a limited segment of utility customers, leaving rates and charges for customers who regularly exceed the minimum bill unaltered.

This report reviews the theory behind the minimum bill mechanism, evaluates the impact of minimum bills in other states and models the potential impact of a minimum bill on a representative PV system in Massachusetts. Key findings include:

- Residential minimum bills that have been implemented in other states have, to date, been relatively modest, ranging from $1.77 per month in one California jurisdiction to $25 per month for large customers of one Hawaii utility.
- Minimum bills have been implemented in some of the most robust solar markets in the country, suggesting that these mechanisms, at the rates implemented, are not incompatible with PV market growth.
- Cash flow modeling of a Massachusetts residential PV system shows that the impact of a minimum bill policy will vary significantly based on the size of the PV system relative to the annual load of a home and the minimum bill level.
- Modeling also indicates that minimum bills could have a greater impact on lower consumption utility customers compared to customers with average consumption assuming both are subject to the same minimum bill.

The next section of this report discusses the theory behind minimum bill policies and provides background information on how net metering charges are recovered by Massachusetts utilities. The third section of this report reviews minimum bill policies in other U.S. states. Section 4 of this report reviews the results of a cash flow model that examined the impacts of multiple potential minimum bill rates on a representative PV system.

2 Minimum Bill Introduction and Background

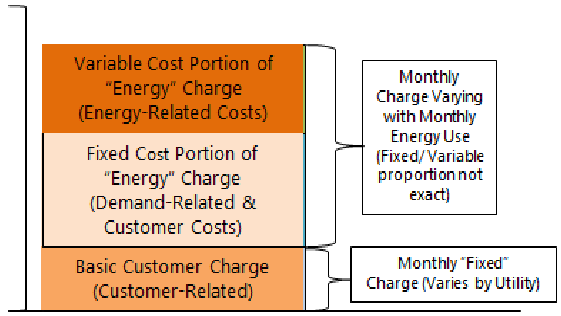
Minimum bill policies have recently been discussed in a number of U.S. jurisdictions as a tool for electric utilities to recover costs from customers using the distribution system but with low net consumption. In part spurred by net metering customers with distributed generation that can significantly reduce monthly bills, these policies have been proposed as a mechanism to reduce both utility lost revenue and ratepayer cross-subsidization associated with net metering. Typically, this mechanism has been proposed as an alternative to other fixed cost recovery mechanisms such as increased customer charges.

Minimum bills (sometimes referred to as minimum bill charges, minimum charges, or minimum monthly contributions) as defined by the Regulatory Assistance Project (RAP) are charges that set a billing threshold under which a customer's monthly bill cannot be further reduced through the application of net metering credits or consumption reductions. After establishing a minimum bill threshold, ratepayers whose bills exceed this value see no increased costs or changes in their bill. Ratepayers whose monthly bills are below the minimum bill threshold are required to pay the dollar value of the threshold. This mechanism ensures electric distribution companies a minimum revenue per customer per month (Lazar, 2014). Minimum bills as defined in this report differ from traditional fixed customer charges in that they only affect low usage customers whose monthly consumption is below the minimum bill threshold while other customers whose monthly bills exceed the threshold value see no change in either their monthly bill or the ratio of costs recovered through fixed and volumetric charges.

2.1 Net Metering, Volumetric Rates and Utility Cost Recovery

Volumetric rates traditionally have been used to recover both variable costs (e.g., electricity supply) as well as portion of a utility's fixed costs (e.g., distribution system investments) for residential and small commercial customers. Figure 1 below shows a simplified breakdown of cost recovery components for a hypothetical utility residential rate. As the diagram shows, both fixed cost and variable-cost components are recovered through volumetric charges while a smaller portion of the total costs are recovered through fixed monthly customer charges.

Figure 1. Generic Residential Rate Design Example[1]



The recovery of fixed utility costs through volumetric rates (as opposed to demand-based rates or fixed charges) promotes energy conservation while eliminating the need for more advanced metering equipment and complicated rate designs. However, recovering fixed costs through volumetric rates allows low-usage customers to pay less of the fixed cost of service associated with their consumption. This can cause distribution system costs to disproportionately shift from lower-usage ratepayers to the remaining ratepayers.[2] As the number of solar net metering customers increases across the country, public utility commissions, solar advocates, utilities and others are working to balance the benefits and costs of distributed generation in the context of existing volumetric rate designs which can shift fixed distribution system costs to customers without net metered systems.

As a counter to this view, some solar advocates have argued that shifting of utility system costs between ratepayers within a rate class or between rate classes is not unique to net metering and that cost shifts between customer types that further public policy goals have a well-established history of broad-based support. In many states, charges related to energy efficiency, renewable energy and low-income programs shift costs and benefits between participating and non-participating ratepayers. These cost shifts have been deemed acceptable by legislators and regulators as furthering broader public policy goals.[3]

In focus group sessions conducted as part of Task 1 some stakeholders expressed the view that current net metering policies created cost shifts between ratepayers that require either new rate structures or the implementation of a minimum bill policy. Other stakeholders said that new approaches to net metering are not needed and that costs associated with current rate structures are acceptable given the public policy goals that net metering rates support.

In addition to reducing cost shifting between net metering and non-net metering customers, minimum bills can also be used as a mechanism to reduce utility lost revenue due to customer on-site generation. This feature of a minimum bill threshold policy is less relevant in Massachusetts as each of the state's investor owned utilities has existing cost recovery mechanisms that enable recovery of lost revenues associated with net metering.

A minimum bill mechanism was introduced as part of the draft legislation negotiated between some members of the solar stakeholder community and the Massachusetts investor owned utilities during the final months of the 2014 legislative session. Section 94J of H 4185 defined a minimum bill as:

> **For all rate classes of each distribution company, the [Department of Public Utilities] shall review and approve a minimum monthly contribution to be included on a customer's total bill that ensures**

[1] In this figure "Energy" refers to a per kWh charge as opposed to an energy supply charge.

[2] https://www.pge.com/regulation/ResidentialElectricRateDesignReform/Testimony/PGE/2014/ResidentialElectricRateDesignReform_Test_PGE_20141017_315103.pdf

[3] http://nccleantech.ncsu.edu/wp-content/uploads/Rethinking-Standby-and-Fixed-Cost-Charges_FINAL-1.pdf

each customer contributes each month a reasonable amount toward the costs of the electric distribution system that are not caused by volumetric consumption. Minimum monthly contributions may differ by rate class and by amount of customer load within each rate class. The [Department of Public Utilities] may exempt or modify the minimum monthly contribution for the low income rate class.[4]

Similarly, the proposed legislation included language in the same section that structured the minimum bill as applicable to all customers within a rate class regardless of whether they owned renewable energy facilities:

The [Department of Public Utilities] shall ensure that any minimum monthly contributions approved in a revenue neutral rate design filing are applied in a nondiscriminatory manner so that customers with renewable energy generating facilities are subject to the same monthly contributions as customers who do not have onsite renewable energy generating facilities.[5]

[4] https://malegislature.gov/Bills/BillHtml/137468?generalCourtId=11
[5] https://malegislature.gov/Bills/BillHtml/137468?generalCourtId=11

2.2 Minimum Bills vs. Increased Customer Charges

One potential mechanism to reduce cost shifts associated with low-demand customers and volumetric rates is to increase fixed monthly customer charges while lowering volumetric charges in a revenue neutral fashion. This approach would allow utilities to recover their fixed distribution system costs through fixed rates that are likely better aligned with the costs of serving customers than are variable rates. There are, however, several potential drawbacks to this approach that run counter to well established public policy goals. For instance, reducing volumetric charges while increasing fixed charges reduces a customer's incentive to conserve energy, and so may drive increased energy consumption. Additionally, increasing fixed charges will likely disproportionately impact low-use, lower income customers. [6]

Alternatively, minimum bills overcome one of these challenges by leaving volumetric kWh prices unaltered, while increasing charges on a small subset of ratepayers whose consumption does not meet the minimum bill threshold. This mechanism may, however, result in bill increases for low income customers with limited electricity consumption. For this reason, establishing a minimum bill threshold that does not create unintended adverse effects for low income customers may require careful consideration of the appropriate rates or specific exemptions for those customers.

Adapted from methodology found in Lazar 2014, Table 1 below shows the total cost for different customer consumption levels for three hypothetical rate structures. The first scenario in the table is a reference case with a low customer charge and higher kWh electricity charge. The second scenario illustrates an increased customer charge applied to all ratepayers with a reduced per kWh charge. The third example is a minimum bill charge set at $20 per month with a small reduction in per kWh charges. For each of these cases, the total costs recovered from customers is identical.

Table 1. Comparison of residential fixed cost recovery scenarios[7]

	kWh Consumption	Low Customer Charge	High Customer Charge	Minimum Bill Charge
Customer Charge		$5	$20	$5
Minimum Bill				$20
Per-kWh Charge		$0.10	$0.0802	$0.096
Customer Consumption	10	$6.00	$20.80	$20.00
	100	$15.00	$28.02	$20.00
	200	$25.00	$36.05	$24.27
	500	$55.00	$60.11	$53.17
	1,000	$105.00	$100.23	$101.35
	1,500	$155.00	$140.34	$149.52
	2,000	$205.00	$180.45	$197.69
Total Costs Recovered		**$566.00**	**$566.00**	**$566.00**

Under the high customer charge scenario, all customers in the low consumption tiers pay higher monthly bills while high-use customers pay substantially lower monthly bills. Under the minimum bill scenario, monthly bills for customers with the lowest usage increase compared to the low customer charge case, but other customers see a modest cost reduction resulting from slightly reduced volumetric charges. This example illustrates how a minimum bill mechanism can be applied to increase cost recovery from very low consumption consumers without increasing costs for other customers or significantly reducing volumetric charges. This case also illustrates the challenge of calibrating a minimum bill threshold so as not to unduly impact low income customers. In the example, the two lowest-tier consumption

[6] http://www.cpuc.ca.gov/NR/rdonlyres/5278BEF7-F533-4ECF-95E0-50DD2B6B67E1/0/FINAL_ED_Staff_Proposal_RateReformforWeb5_9_2014.pdf
[7] Adapted from Lazar 2014

customers (10kWh and 100kWh)[8] see higher bills under the minimum bill scenario compared to the reference scenario, but the third lowest consumption tier (200kWh) sees a slight bill reduction compared to the reference case.

2.3 Net Metering in Massachusetts

In Massachusetts, customer generators have the ability to reduce their utility bills either through installation of on-site generators or through the application of net metering credits from off-site generators (aka., virtual net metering). Net metering credits applied to customer bills can reduce utility bills significantly and customers have the ability to roll over the monetary value of excess credits for use in future billing periods. These bill credits can be used to offset all bill charges including demand charges, customer charges and other costs, allowing customers to pay their entire monthly bills though the application of net metering credits.[9]

Investor owned utilities (IOUs) in Massachusetts recover lost revenue associated with customer net metering (including both on-site net metering and virtual net metering) through either a Revenue Decoupling Mechanism (RDM) or through a Net Metering Recovery Surcharge (NMRS).[10] RDMs establish a fixed annual revenue requirement for a utility and allow the utility to recover costs through an increasing per kWh charge that adjusts with reduced customer consumption.[11] This mechanism is intended to make utilities indifferent to the customer activities that may reduce consumption such as energy conservation measure installations or on-site generation. Recovery of net-metering related costs is one of many components associated with this charge. NMRSs are a more proscribed charge that allows a utility to recover lost revenue and other costs associated with providing net metering service through an incremental charge on all kWh sales in their territory. In Massachusetts, both these revenue recovery mechanisms are regulated by the DPU and reconciled on an annual basis. National Grid currently uses a RDM mechanism to recover its net metering associated costs and lost revenue along with other cost elements. WMECO and Unitil use a combination of NMRSs and RDMs to recover their net metering costs and lost revenues. NSTAR exclusively uses an NMRS for net metering cost recovery.

Over the past several years, as more customers have taken advantage of net metering, these RDM and NMRS charges have increased to allow utilities to recover the increasing loss of revenue associated with distributed generation growth. Table 2 below shows the most recent effective NMRS and RDMs for residential customers of the Massachusetts investor owned utilities. Total aggregate distribution charges are listed as well for reference. As noted above, net metering associated costs contribute to RDM charges, however RDMs are structured to recover costs from a much broader range of utility activities than just net metering.

[8] For reference, the average National Grid residential customers uses around 600 kWh per month. Few customers are likely to have consumption in the 10 to 100 kWh per month range.

[9] https://sites.google.com/site/massdgic/home/net-metering/net-metering-credit-example

[10] Unitil, WMECO and NSTAR recover net metering-related revenues through a NMRS, while National Grid recovers its net-metering related lost revenue through its RDM. WMECO, National Grid, and Unitil are decoupled, and therefore recover their annual target revenue on a reconciling basis; these companies are therefore not negatively impacted by lost sales from increased distributed generation. Currently, NSTAR Electric is not decoupled, and so does not recover lost distribution revenue from reduced sales due to increased distributed generation.

[11] NMRSs can also be used to provide credits back to customers in the event utilities over-recover their costs in a given year.

Table 2. Current NMRS and RDM rates for Massachusetts IOUs[12]

Utility Territory	Current Residential NMRS per kWh	Current Residential RDM per kWh	Current Total Residential Distribution Charge (First Block) per kWh
Eversource - Western Mass Electric Company	$0.00172	$(0.00280)	$0.04006
Fitchburg Gas & Electric (d/b/a Unitil)	$0.00199	$0.00638	$0.11220
Eversource – NSTAR BECO	$0.00200	N/A	$0.08287
Eversource – NSTAR Cambridge Electric	$0.00360	N/A	$0.08196
Eversource – NSTAR Commonwealth Electric	$0.00199	N/A	$ 0.09280
National Grid	N/A	$0.00069	$0.07161

These revenue recovery mechanisms protect Massachusetts utilities from lost revenues associated with net metering, eliminating one barrier to wider adoption of customer-sited generation. Under its current structure, net metering does, however, create distributional effects between net metering customers and non-net metering customers. For instance, as part of its 2015 NMRS request, NSTAR requested to recover $30.8 million in costs associated with net metering. As per NSTAR's net metering tariff, this value includes:

(1) The value of any net metering credits paid to customers the previous year;
(2) Lost distribution revenue associated with on-site power consumption by net metered customers;
(3) The total amount under-recovered costs during the previous year under the NMRS mechanism.

These costs are reduced by revenues received by NSTAR for power sold into the ISO-NE market from Class II and III net metering generators.

Recent filings by National Grid as part of their annual RDM filings indicated that $40.1 million in net metering credits were provided to customers in 2014 while $12.2 million was recovered through sales of electricity to ISO-NE from Class II and Class II net metered generators. As of this writing, the cost associated with lost distribution revenues from displaced customer consumption has not been published.[13]

Recovery of these charges represents a cost to non-participating ratepayers and a benefit to customer generators. Under these cost recovery models, as participation in net metering increases over time, the shift in costs associated with net metering will increase.

Some analysts have argued in other states that net metered customers provide additional benefits to the utility system that benefit non-participating customers and that are not monetized in simplified net metering costs recovery frameworks. Potential benefits that are not accounted for in the Massachusetts NMRS model could include avoided transmission and distribution investments. If these avoided utility costs were integrated into the NMRS cost recovery framework, total recoverable net metering costs would be lower. In theory and over the long term, the additional costs avoided by the installation of customer-sited generation are accounted for by a RDM where any avoided costs to the distribution system associated from customer generators would result in lower the applicable RDM charges.

[12] http://nuwnotes1.nu.com/apps/wmeco/webcontent.nsf/AR/SummaryOfElectricRates/$File/Summary_of_Rates.pdf; http://unitil.com/sites/default/files/tariffs/E_dpu274_Summary_of_Rates_010115.pdf; http://www.nationalgridus.com/masselectric/non_html/rates_tariff.pdf;
[13] http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=14-136%2fNG_supp_testimony.pdf

3 Minimum Bill Policies in Other States

A number of other states have either implemented or are actively exploring implementing minimum bill mechanisms. To date, the policies that have been implemented have included relatively modest minimum bills, ranging from $1.77 per month in one California utility territory to up to $25 per month in Hawaii. These states have some of the most robust solar markets in the United States, suggesting that minimum bills, as implemented, are not fundamentally incompatible with solar market development. The following section reviews experiences in these states and other states.

3.1 Minimum Bill Policies in California

California's investor owned utilities have small, longstanding minimum bill rates. Similarly, several California municipal utilities have implemented minimum bills or have recently increased fixed charges in part as a result of increased customer DG adoption. The following two sections discuss these California utilities.

3.1.1 Current and Future Investor Owned Utility Policies

Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E), California's three largest investor-owned utilities have established residential minimum bill policies in place. This alternative to fixed charges was first authorized in a 1981 California Public Utilities Commission (CPUC) ruling.[14] These charges are billed as daily minimum meter charges and are meant to help utilities cover fixed costs for transmission, distribution, billing and metering. The current fee structure for each of that state's IOUs is summarized in Table 3 below.

Table 3. California IOU Minimum Bill Charge Structures

Utility	Minimum Charge ($/meter/day)	Total Monthly (30-days)
PG&E[15]	$0.14784	$4.435
SDG&E[16]	$ 0.170	$5.10
SCE[17, 18,19]	$0.059	$1.77

Some California utilities additionally provide separate, reduced minimum bill charges for qualifying low-income customers as well as separate rates for multi-family residences. Given the longstanding nature of these minimum charges and their relatively modest rates, and the fact that California has been a leading solar state for many years, it is unlikely that these minimum bill mechanisms have significantly impacted the growth of customer-sited generation in California.

In October 2013, the California legislature passed Assembly Bill 327 (AB 327) which has a number of implications for the future of the state's solar market development and net metering programs. The bill marked the start of a regulatory reform process by removing restrictions which had previously limited changes to residential rates. This shift was motivated by inequities and cost shifts in the existing rate structure. AB 327 requires the state's current net metering program to end by July 1, 2017 or when investor owned utilities (IOUs) reach their existing program caps. Existing net metered generators would continue to receive net metering credits at the retail rate under the current program for the

[14] http://www.cpuc.ca.gov/NR/rdonlyres/5278BEF7-F533-4ECF-95E0-50DD2B6B67E1/0/FINAL_ED_Staff_Proposal_RateReformforWeb5_9_2014.pdf
[15] http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-1.pdf
[16] http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_DR.pdf
[17] http://www.abcsolar.com/pdf/ce12-12.pdf
[18] https://www.sce.com/NR/rdonlyres/E4420035-F7BE-4863-8E59-F4B3EFE2B360/0/090824_Net_Metering_NEM_Fact_Sheet.pdf
[19] SCE has a separate minimum bill rate for multi-family residential customers of $0.044 $/meter/day

useful life of their system. However, new generators will be required to use a new uncapped net metering program which will be designed through a CPUC processes. The CPUC is expected to announce the details of the revised net metering program, which will feature a standard contract, before 2016. Additionally, AB 327 allows for utilities to file for new rate design proposals including fixed charges or minimum bills capped at $10/customer.[20]

During the stakeholder process that resulted in the CPUC's residential rate design recommendations, a number of stakeholders made arguments for and against minimum bill policies. For instance, utility stakeholders argued that fixed charges were superior to minimum bill programs as they better reflect cost causation principles that ensure fairness amongst ratepayers. Similarly, utility stakeholders argued that allowing distributed generators to avoid fixed customer charges amounted to an arbitrarily set incentive. Additionally, stakeholders in favor of fixed charges argued that these mechanisms did not necessarily reduce customer incentives to invest in energy efficiency and that volumetric charges set to recover fixed utility costs may lead to customer energy efficiency investments that were not cost effective from the societal perspective. Proponents of minimum bills argued that these mechanisms have the benefit of reducing free ridership without altering the economic incentive for most customers to invest in energy efficiency.[21]

In the CPUC's *Staff Proposal for Residential Rate Structure*, the CPUC stated that a minimum bill could be considered as an alternative to a fixed charge for utilities if the minimum bill was initially capped at $10/month per customer and $5/month for low-income customers. Any minimum bill rate could adjust with inflation over time. The CPUC agreed with commenters that a minimum bill would prevent free ridership from zero or low-consumption customers, and not unduly penalize other ratepayers.[22] In the case of either a fixed charge or minimum bill thresholds, the Commission would require that the charge reflect the cost of service for customer classes, prevent significant erosion of incentives for conservation, and minimize burdens on low-income customers. The CPUC will begin to consider new fixed charges or minimum bills this year as utilities make revised residential rate proposals.

3.1.2 California Municipal Utility Programs

In addition to the IOU minimum bill programs, two municipal utilities, Sacramento Municipal Utility District (SMUD) and the Los Angeles Department of Water and Power (LADWP) have existing fixed charge or minimum bill policies in place that establish non-zero minimum monthly contributions. Both SMUD and LADWP have a significant penetration of net metering customers, with LADWP having over 12,000 installations as of April 2014.[23] The details of their programs are discussed below.

Los Angeles Department of Water and Power (LADWP)

As part of its strategy to stabilize revenues, LADWP began a rate reform process in 2008, which included revenue decoupling.[24] As part of this process, LADWP instituted a minimum charge for some residential customer rates.[25] Los Angeles has one of the most robust municipal solar markets in the United States and, as of July 2014, had the most net energy metering customers of any municipal utility in the country with over 12,000 installations.[26] LADWP has offered solar incentives since 1999, and currently offers a declining block incentive program for its customers.[27] LADWP's net

[20] SEIA. US Solar Market Insight 2013 Year in Review. Online Subscription. 2013.

[21] http://www.cpuc.ca.gov/NR/rdonlyres/5278BEF7-F533-4ECF-95E0-50DD2B6B67E1/0/FINAL_ED_Staff_Proposal_RateReformforWeb5_9_2014.pdf

[22] http://www.cpuc.ca.gov/NR/rdonlyres/5278BEF7-F533-4ECF-95E0-50DD2B6B67E1/0/FINAL_ED_Staff_Proposal_RateReformforWeb5_9_2014.pdf

[23] http://clkrep.lacity.org/onlinedocs/2014/14-0531_rpt_dwp_06-17-14.pdf

[24] http://www.dwpreform.lacity.org/documents/CostReductionReport20120823.pdf

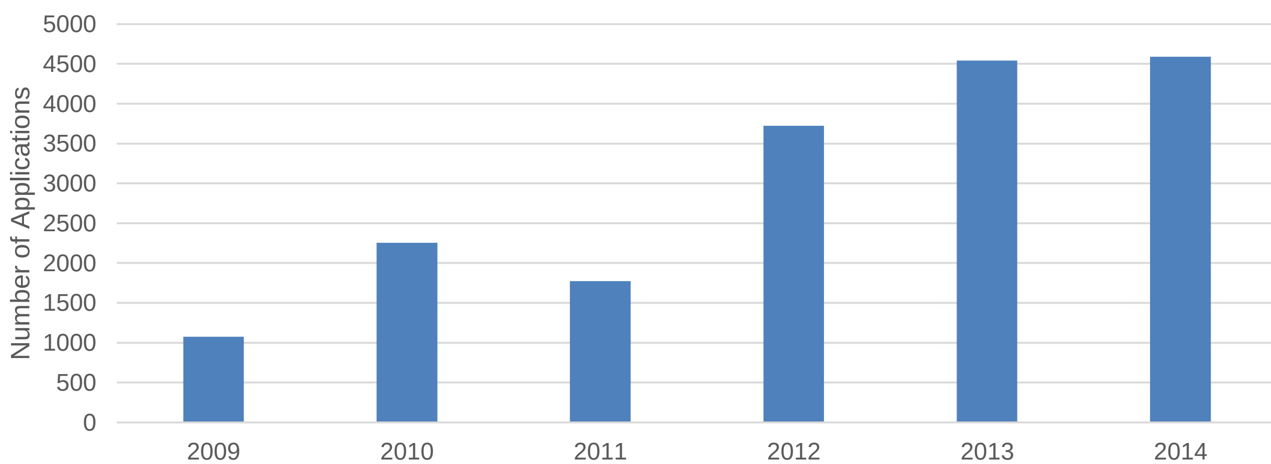
[25] http://clkrep.lacity.org/onlinedocs/2012/12-1504_RPT_ATTY_09-18-12.pdf

[26] https://www.ladwp.com/cs/idcplg?IdcService=GET_FILE&dDocName=QOELLADWP006837&RevisionSelectionMethod=LatestReleased

[27] https://ladwp.com/ladwp/faces/wcnav_externalId/c-gg-progstusincentlevl;jsessionid=vJ2NJLJhvqcXkBJq9BTnT4ylQDFwwTz486BvbGRBkTK2StyWFWBv!1320183872?_adf.ctrl-state=14c4ja77cg_4&_afrLoop=650386073165028&_afrWindowMode=0&_afrWindowId=null#%40%3F_afrWindowId%3Dnull%26_afrLoop%3D650386073165028%26_afrWindowMode%3D0%26_adf.ctrl-state%3Da7vmwx2bk_4

metering program credits excess generation at the retail rate, though the utility has proposed studying other policy alternatives before the current program ends in December 2016.[28] Solar systems up to 1MW can qualify for the program and virtual net metering is not allowed under current net metering rules. Net metering credits cannot be used to reduce a customer's bill below the minimum charge.[29] Thus, if a customer is low or zero usage, they still have to pay the minimum charge associated with their rate class. For residential customers using Standard Residential Rate (R1-A), this charge is currently $10. This $10 minimum bill has been in effect since at least 2009. Figure 2 below shows the annual applications from the LADWP solar program from 2009 to 2015. During this period, solar installations in LADWP's utility territory have grown substantially, suggesting this minimum bill mechanism has not been a substantial barrier to market growth during this period.

Figure 2. Applications for LADWP Solar Incentive Program 2009-2014



LADWP has proposed additional rate reforms to unbundle residential rates into generation, distribution and transmission components so that net metering credits can be applied to the most appropriate portion of customer bills. This was proposed in order to prevent further cost-shifts after the net metering program expands beyond the current 310MW cap.

Sacramento Municipal Utility District (SMUD)

SMUD installed the nation's first utility scale solar system in 1984, and has remained supportive of solar energy development. The municipal utility offers net energy metering for distributed generators up to 1 MW in size, and a community solar program called Solar Shares. SMUD compensates excess generation at the retail rate and exempts distributed generators from standby charges.[30] SMUD also provided a feed-in-tariff for solar energy until the program reached capacity in 2010. Residential systems now qualify for a $500 upfront payment incentive. As of January 2015, SMUD had processed over 5,000 applications for its incentive programs.[31]

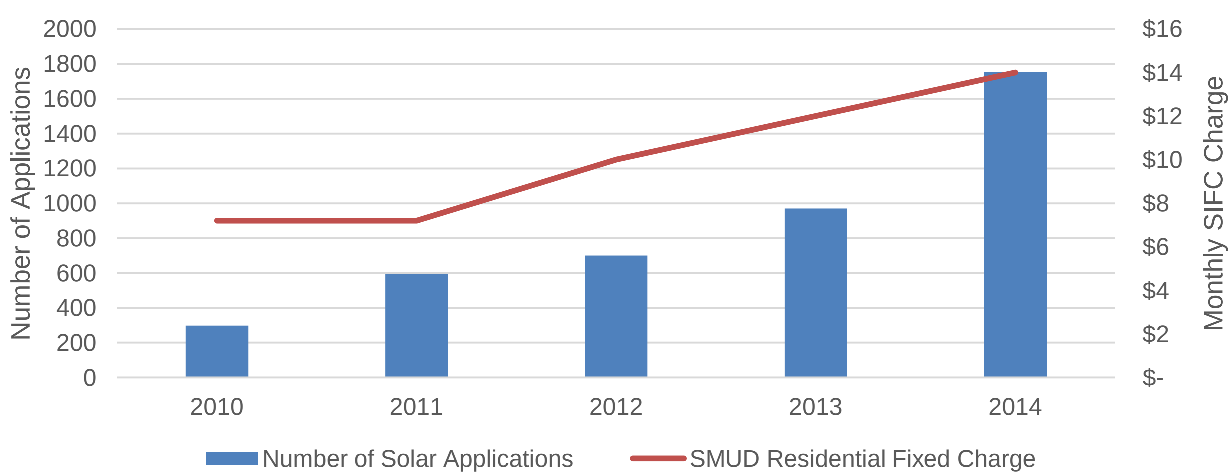
During a recent review of its rates, SMUD found that 75 percent of residential customers were not paying their full cost of service. The utility is currently undergoing a residential rate reform process to allow rates to more accurately reflect cost of service. SMUD intends to shift entirely to time-of-use residential rates by 2017, and is undergoing a process to reduce its tiered residential rate system.

[28] http://clkrep.lacity.org/onlinedocs/2014/14-0531_rpt_dwp_06-17-14.pdf
[29] http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA66R&re=0&ee=0
[30] https://www.smud.org/en/residential/environment/solar-for-your-home/documents/Net%20Metering%20for%20Qualifiying%20Facilities.pdf
[31] http://smud.powerclerkreports.com/Default.aspx?ReportId=4

In addition to rate reform, SMUD began increasing its System Infrastructure Fixed Charge (SIFC) in 2012 in order to help recover the fixed costs of serving utility customers. These increased fixed charges were matched with reductions in volumetric kWh charges. SMUD's board approved these changes to more closely align with the cost to serve each customer. This charge is assessed on all bills and is set to escalate to $20 for residential customers by 2017 to cover 100 percent of customer and distribution costs. The current residential fixed charge has risen to $16 from $7.20 per customer in 2011. As a fixed charge, the SMUD SIFC is not a minimum bill policy as defined in this report as the charge, when implemented, led to a rate increase for all customers regardless of consumption. However, like a minimum bill, the SIFC cannot be avoided through net metering credits or conservation.[32]

Despite not being structured as a minimum bill, this rate mechanism can provide some limited insight into the potential effects of a minimum bill policy on solar market development. SMUD's fixed charge has increased gradually since 2012 for all rate classes. Despite this, SMUD has continued to see a growth in applications for its solar program. Figure 3 below shows the annual number of residential solar program applications between 2010 and 2014 along with the applicable residential SIFC charge. As the figure shows, the number of solar program applications continued to grow as the charge increased, suggesting that the charge has not been a significant barrier to local solar market growth. Notably, this simplified analysis does not take into account changes to solar installed costs over this time period or reductions in SMUD incentives which likely have more significant influences on solar market growth rates.

Figure 3. SMUD PV Program Applications and SIFC Charge Rates 2010-2014



3.2 Minimum Bills in Hawaii

Hawaii has one electric holding company (collectively known as the HECO Companies) that serves three separate utility territories, Hawaii Electric Company (HECO), Maui Electric Company (MECO), and Hawaii Electric Light Company (HELCO). The state has the highest per-capita solar penetration in the United States, with more than 10 percent of residential customers having PV installations in some utility territories.[33] Driven by high fuel costs, electricity prices in Hawaii are some of the highest in the nation, with average residential electricity prices ranging between $0.39 and $0.46

[32] https://www.smud.org/en/residential/customer-service/documents/PV-bill-sample.pdf
[33] http://www.greentechmedia.com/articles/read/How-Much-Solar-Can-HECO-and-Oahus-Grid-Really-Handle

per kWh in 2013.[34] Hawaii has had robust utility solar incentives over the past decade, with Hawaii utilities offering both a feed-in tariff program and net metering.[35]

Each of Hawaii's IOU territories includes minimum charges in each of their tariff rates. These charges have been in place since before the development of the state's solar PV market. For residential customers, minimum charges are in addition to the monthly customer charges and must be paid in the event that customer consumption drops below the minimum charge threshold. Customers that exceed the monthly minimum bill are not subject to any additional monthly charges as a result of this mechanism. Table 4 below shows the current minimum charges for each of the three Hawaii IOU territories for the residential rate.

Table 4. Residential Minimum Charges for Hawaii IOU Territories[36]

	Single Phase Minimum Charge per Month	Three-phase Minimum Charge per Month
Hawaii Electric Co. (HECO)	$17.00	$23.00
Hawaii Electric Light Co. (HELCO)	$20.50	$25.00
Maui Electric Co. (MECO)	$18.00	$22.50

Minimum charges for demand metered customers are defined as the sum of the customer charge and any applicable demand charges. Because these minimum charges for demand metered customers are effectively the same as the charges that would be paid by any customer in the rate class regardless of consumption, they are fundamentally different from the minimum charge structure that is applied to residential rates. This minimum charge structure effectively ensures that standard demand charges cannot be bypassed through conservation or net metering.

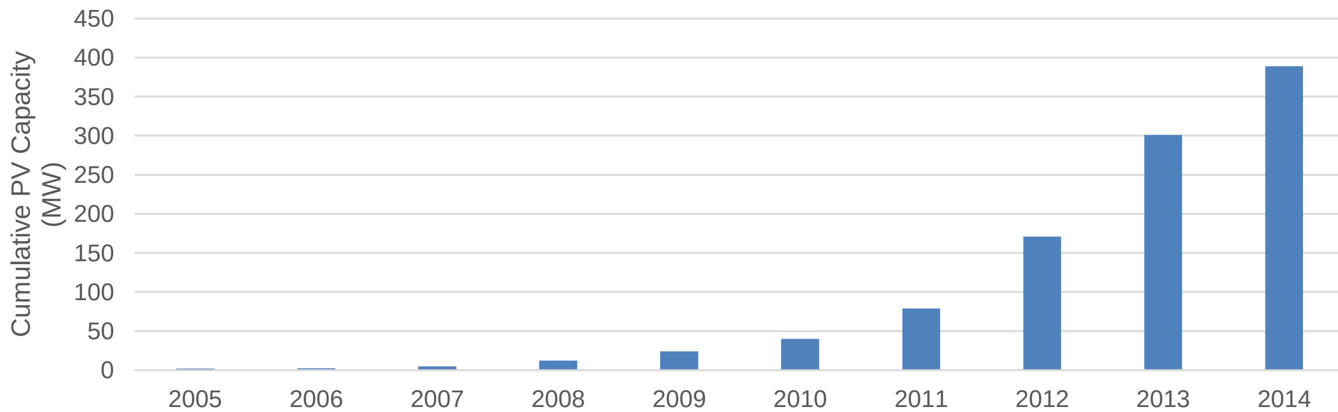
Hawaii has seen robust solar market growth over the past several years. Figure 4 shows the cumulative PV capacity in the HECO Company territories between 2005 and 2014. Given this aggressive market growth, the relatively high minimum bill charges applied to distributed generation customers do not appear to have created a significant barrier to solar market development. Critically, these relatively high minimum charges are being applied in a market with substantially higher retail electricity prices than seen in mainland U.S. utility territories, potentially mitigating any effects of the charges on solar market development.

[34] http://www.hawaiianelectric.com/heco/Residential/Electric-Rates/Average-Electricity-Prices-for-Hawaiian-Electric,-Maui-Electric,-and-Hawaii-Electric-Light-Company

[35] Feed-in tariff rates have been below retail electricity rates leading most distributed generators to opt to net metering their systems instead of taking the feed-in tariff incentive. http://energy.hawaii.gov/wp-content/uploads/2014/11/HSEO_FF_Nov2014.pdf

[36] http://www.hawaiianelectric.com/vcmcontent/StaticFiles/FileScan/PDF/EnergyServices/Tarrifs/HECO/EFFRATESSUMFEB2015.pdf

Figure 4. Cumulative PV Capacity in MW in HECO Company Territories[37]



In January 2015, the HECO Companies submitted a request to the Hawaii Public Utility Commission for approval of a Transitional Distributed Generation Plan as part of ongoing efforts to reform the utility business model in the state to increase renewable energy generation. The transitional plan recommended significant changes to the existing net metering framework, including transitioning from full retail rate net metering to generation payment rates set equal to the utility's avoided fuel cost.[38] This proposal has received a significant negative response from the solar stakeholder community in Hawaii and is currently the subject of ongoing regulatory consideration. At the same time, Hawaii's IOUs have proposed, as part of the state's broader renewable energy transition process, to move towards a rate structure with higher minimum charges and lower volumetric rates. The HECO Company's initial filing proposed illustrative minimum residential charges of $55 for customers without on-site generation and $71 for customers with on-site generation. In the example offered, these higher minimum charges would be offset by lowering electricity rates from $0.34 per kWh to $0.26 per kWh for residential customers.[39] The final outcome of this reform proposal is currently pending.

3.3 Ongoing Net Metering Cost Recovery Discussions in Other States

Discussions about the future of net metering and the potential applicability of minimum bills are ongoing in a number of states. The following section provides background information on several of these state-level policy discussions.

3.3.1 Arizona

In 2013, Arizona Public Service (APS) went before the Arizona Corporation Commission (ACC) with two proposals to address ratepayer cost-shifting resulting from their existing net metering program. In support of this request, APS indicated that it received an average of 500 net metering applications per month and estimated that each system resulted in $800-$1,000 in added costs to non-ratepayers annually.[40] As part of the regulatory proceedings, solar advocates submitted a study which concluded that the benefits of DG systems exceeded the costs and argued that net metering under-compensated DG generators.[41] APS proposed transitioning net metering customers to time of use rates

[37] http://www.hawaiianelectric.com/vcmcontent/StaticFiles/pdf/PVSummary_4thQtr2014.pdf
[38] http://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A15A20B13419D2782918+A15A20B45226C873931+14+1960
[39] http://www.hawaiianelectric.com/heco/_hidden_Hidden/CorpComm/Questions-and-Answers-for-Hawaii%27s-Energy-Future-Plan?cpsextcurrchannel=1#bk7
[40] http://images.edocket.azcc.gov/docketpdf/0000149849.pdf
[41] http://images.edocket.azcc.gov/docketpdf/0000149849.pdf

with demand charges or shifting DG customers to a buy-all, sell-all approach to address these costs.[42] APS's proposed demand charges under either of the existing residential rate structures significantly eroded savings for net metering customers.[43] Several protests were filed which stated the APS analysis excluded the benefits of DG, and that such changes were more appropriately addressed by a rate case.

The ACC noted that existing studies of the value of DG were inconclusive and that imposition of demand charges or a tariff approach for DG customers would be more appropriately addressed in a rate case. The ACC rejected both of APS's proposals in favor of an interim adjustment to APS's Lost Fixed Cost Recovery Mechanism of $.70/kW, resulting in a revenue neutral charge for all new systems installed after December 31, 2013. Existing generators would not be subject to any changes until after APS's next rate case in 2015.[44]

In addition to the APS rate design discussions, the Salt River Project (SRP), an Arizona public power provider, has recently approved a new demand charge on solar customers as part of a broader rate restructuring effort. Reports have indicated that this new solar demand charge could increase residential solar customer's bills by $50 per month. SolarCity, a national solar installation company with a significant presence in Arizona, has filed a lawsuit in an effort to block implementation of the new solar demand charge.[45]

3.3.2 Kansas

In 2014, Kansas legislators voted to continue the state's net metering program with modifications. House Bill 2101 allowed utilities to submit proposals to the Kansas Corporation Commission on minimum bills, time of use rates or other rate structures for DG after July 1, 2014.[46] As of yet, however, Kansas' IOUs have not proposed a minimum bill or other cost recovery mechanism to the Commission. The bill also reduced the eligible system size for net metering. Residential size caps decreased from 25 to 15 kW, commercial systems sizes dropped from 200 to 100 kW and non-profit or public sector systems are now capped at 150 kW. The bill also reduced the credit for excess generation from the retail rate to avoided costs. Systems installed prior to July 1st, 2014 are grandfathered under the current program until 2030. In April 2014, Kansas had approximately 200 net-metered systems. The bill was considered a compromise in Kansas since the original proposal would have eliminated the state's net metering program.[47]

3.3.3 Oklahoma

In April 2014, the Oklahoma legislature passed Senate Bill 1456 which was designed to prevent the cross-subsidization of distributed generators by other ratepayers. The law enables utilities to impose fixed charges solely on DG customers in a rate class as long as the charge is justified. Utilities are allowed to submit proposed tariffs to the Oklahoma Corporation Commission (OCC) by the end of 2015.[48] The law was later clarified via an Executive Order in July 2014. The Executive Order stated that the OCC could consider alternative policy choices, such as minimum bills, time of use rates and demand charges before implementing fixed charges. At present, no tariffs have been proposed to the OCC. As of July 2014, Oklahoma IOUs had approximately 350 DG customers.[49]

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[42] Under a buy-all, sell-all approach, distributed generation owners sell the entirety of the generation of their system to the grid, using no self-generated power on site.
[43] http://images.edocket.azcc.gov/docketpdf/0000149849.pdf
[44] http://nccleantech.ncsu.edu/wp-content/uploads/Rethinking-Standby-and-Fixed-Cost-Charges_V2.pdf
[45] https://www.greentechmedia.com/articles/read/solarcity-files-lawsuit-against-salt-river-project-for-antitrust-violations
[46] http://www.kslegislature.org/li/b2013_14/measures/documents/hb2101_enrolled.pdf
[47] http://www.midwestenergynews.com/2014/04/07/in-defeat-for-alec-kansas-lawmakers-pass-net-metering-plan/
[48] http://webserver1.lsb.state.ok.us/cf_pdf/2013-14%20ENR/SB/SB1456%20ENR.PDF
[49] https://www.sos.ok.gov/documents/executive/938.pdf

3.3.4 Texas

The Texas Public Utility Commission allows Retail Electricity Providers (REPs)[50] to assess minimum or low usage charges on customers with low consumption.[51] This threshold is defined by each REP. A study by the Texas Ratepayers' Organization to Save Energy documented that the number of Texas retail electricity providers assessing minimum usage fees grew from 36% to 81% between 2011 and 2013. In most cases, the usage fees trigger when customers use 1,000 kWh or less of electricity and range in price from $6-$20. These fees tend to be disclosed in the terms of service for each provider.[52] The cumulative capacity of solar installations in the state grew by 307% between 2011 and 2013, however a limited portion of this growth was behind the meter systems.[53] Texas does not currently have a statewide net metering policy – existing programs are determined at the utility-level.

[50] Texas has transitioned to a retail electric competition model under which REPs provide service through regulated Transmission and Distribution Utilities (TDUs) allowing REPs them to offer full service electric generation, transmission and distribution services for retail customers. https://www.puc.texas.gov/industry/electric/business/rep/Rep.aspx

[51] http://www.puc.texas.gov/consumer/facts/factsheets/elecfacts/ChargesElectBill.pdf

[52] http://texasrose.org/wp-content/uploads/2013/08/Fees-Summary-2013-Report-by-Texas-ROSE.pdf

[53] IREC. Solar Market Insights Report. 2008-2014.t

4 Minimum Bill Modeling

In order to explore the dynamics of a potential minimum bill both on individual customer utility charges and PV system economics, a simplified PV system cash flow model was developed. To isolate the potential impacts of a minimum bill policy and evaluate a range of policy and system parameters, modeling was conducted on a representative residential PV system. A series of sensitivity analyses were conducted to explore how different minimum bill levels might lead to different project cash flow parameters and utility charges. Modeling outputs included total utility charges recovered, simple payback and internal rate of return (IRR). The following sections review the assumptions and results of this modeling exercise. Critically, the results of this section are specific to the system type modeled and the assumptions used. The production, economics and on-site load parameters are unique for each PV system in Massachusetts, with no two systems being alike. The results found in this section were developed with the intent of informing the Massachusetts net metering task force regarding the dynamics of a potential minimum bill policy. This is not intended as a minimum bill rate setting exercise or as a conclusive exploration of the merits of a minimum bill policy over other potential policy mechanisms.

4.1 Modeling Parameters

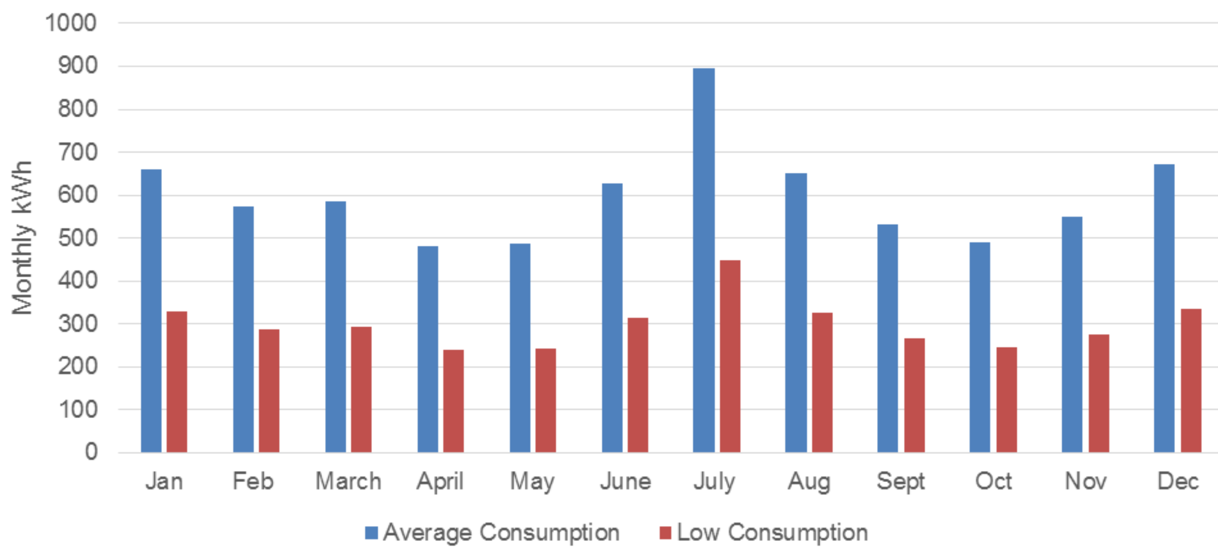
The following section describes the major modeling parameters used to evaluate the potential effects of a minimum bill on utility costs recovery and PV system economics.

4.1.1 Onsite Load

The National Grid basic service R-1 hourly load data from 2013 was used as the modeled home electricity consumption under this task.[54] This system-wide hourly load curve data was normalized on a percentage basis and scaled to create two hourly annual load curves, one for a home using an average of 600 kWh per month ("Average Consumption") and another for a home using an average of 300 kWh per month ("Low Consumption"). This corresponds to an average National Grid residential customer and a low-usage customer. These scaled hourly load profiles were transformed to create monthly load profiles for each of the two load cases. Figure 5 below shows the two monthly electricity consumption profiles used in the modeling.

[54] http://www.nationalgridus.com/energysupply/mass_data_ds.asp

Figure 5. Modeled Monthly Consumption Profiles



4.1.2 PV System Parameters

The modeled system was assumed to have a 20-year life. PV system parameters were adjusted National Renewable Energy Laboratory's PVWatts program to develop a monthly kWh production profile for a residential PV system that aligned with historic Massachusetts PV system production.[55] Solar insolation data from Worcester, Mass. was selected for developing the production profile. Table 5 below shows the default PVWatts parameters while Figure 6 below shows the monthly PV production profile for a representative 1kW system.

Table 5. PV System Modeled Parameters[56]

PV System Assumptions		
Production Profile	PV Watts Standard Assumptions for Worcester, MA	
Array Tilt	35	Deg
Array Azimuth	190	Deg
System Losses	24%	Percent
Inverter Efficiency	96%	Percent
DC to AC Size Ratio	1.1	
System Degradation	0.50%	Percent per year
Annual production	1,180	kWh/kW

For the minimum bill analysis, a range of system sizes were used to evaluate the potential effects of differing minimum bill levels on multiple PV system sizes. For the analysis, four system sizes were evaluated for each of the two representative home load cases. These system sizes were modeled to cover 120%, 100%, 80% and 60% of a homeowner's annual load. Table 6 below shows the system sizes modeled for each of the site annual consumption cases.

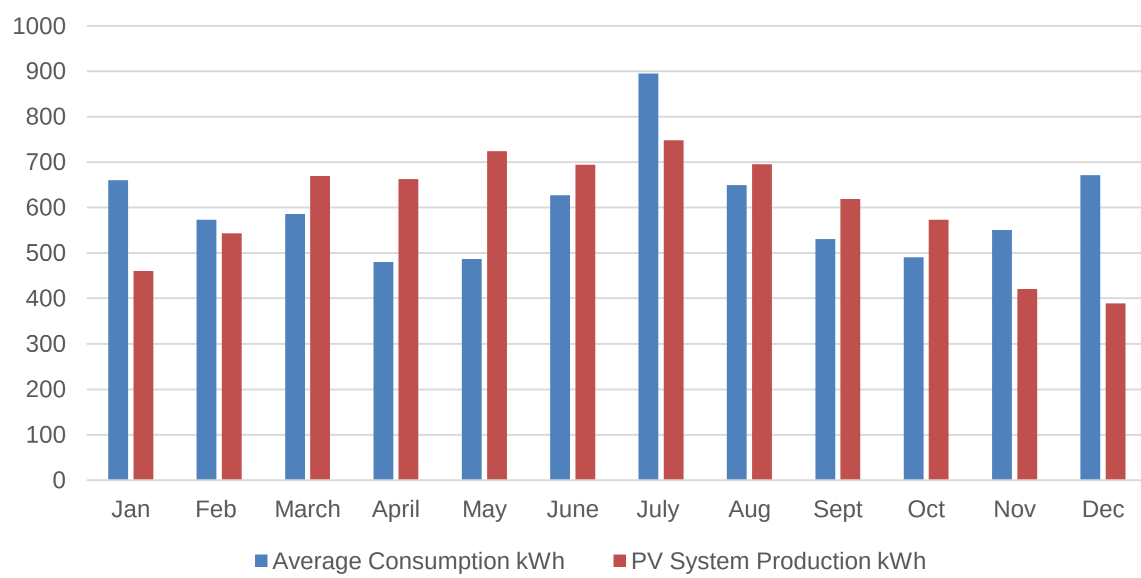
[55] http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/solar/rps-solar-carve-out/current-status-of-the-rps-solar-carve-out-program.html
[56] http://pvwatts.nrel.gov/pvwatts.php

Table 6. PV System Sizes Modeled

PV Production to Annual Consumption Ratio	Average Consumption Case	Low Consumption Case
120%	7.32 kW	3.66 kW
100%	6.10 kW	3.05 kW
80%	4.88 kW	2.44 kW
60%	3.66 kW	1.83 kW

Table 5 below shows the monthly PV system production profile for a 6.1 kW system with the annual load profile for the average home load case. Under this scenario, the PV system provides 100 percent of the annualized electricity consumption.

Figure 6. 6.1 kW PV System Monthly Production and Average Consumption Monthly Profile



4.1.3 Financial Assumptions

Across Massachusetts, there is significant variation in PV system ownership models and financing structures. In order to best isolate the potential effects of a minimum bill on PV system economics and eliminate potential confounding effects related to system economic financing assumptions, the modeled systems in this analysis assumed a cash purchase by the homeowner. While this assumption represents only one of many potential ownership and financing models currently used in Massachusetts, and may not represent the majority of residential PV systems currently in the marketplace, it was chosen as a simplifying assumption that would allow for a more straightforward exploration of a minimum bill on the dynamics of PV system economics. As such, the investment return values presented as outputs to this analysis may not be representative of typical returns currently seen for PV system in Massachusetts.

In order to model a range of potential system paybacks and investment returns, three cost cases were modeled. Individual cases were examined assuming $3, $4 and $5 per watt system installation costs. This represents a broad range of potential system costs that is representative of the range of system prices reported in the latest DOER SREC II public dataset. One assumption that was made in order to simplify the analysis is that PV system costs do not benefit from economies of scale. A homeowner purchasing a 7.3 kW system may be able to benefit from a lower per watt price than the same homeowner purchasing a 3.7 kW system. This effect was not modeled and would tend to improve the economics of larger systems relative to smaller systems in the analysis.

4.1.4 Utility Bill Parameters

Modeled utility bill parameters were based on National Grid R-1 distribution rates.[57] Distribution rates for net metering credits from exported power were assumed to not include the energy efficiency and renewable energy charges. Separate basic service supply rates were modeled for winter periods (November through April) and summer periods (May through October). Basic service rates for summer and winter periods were based on the average basic service rates for those periods over the last five years. A five-year average was chosen instead of the most recent year basic service rates in order to lessen the effects of recent high winter basic service rates on modeling. Additionally, a $4 customer charge was applied to each monthly period modeled. All utility bill elements were escalated throughout the analysis at a 1.89% annual rate.

Table 7. Electricity Bill Component Parameters

Electricity Value of Production and Utility Bill Components		
Starting Customer Charge	$4.00	National Grid R-1 Customer Charge
Starting Distribution Rate for On-site Consumption	$0.07426 $0.08008	National Grid R-1 Distribution Rates[58]
Starting Distribution Rate for Monthly Exported Power	$0.0611	National Grid R-1 Distribution Rate minus EE and RE Charges
Staring Basic Service Supply Summer (May - October)	$0.0753	Average of last five years[59]
Starting Basic Service Supply Winter (Nov - April)	$0.0999	Average of last five years[60]
Utility Bill Escalation Factor	1.89%	Annual Escalator for All Bill Components[61]

4.1.5 Minimum Bill Parameters

Four minimum bill cases were modeled: $4, $10, $25 and $50.[62] Additionally, a base case without a minimum bill was modeled. Like the other bill components, the minimum bill was assumed to escalate yearly at 1.89%. The minimum bill was structured as the non-zero lowest potential bill threshold for each month modeled. During months in which there was a calculated utility bill that exceeded the minimum bill, previously banked net metering credits, if available, were first used to reduce the utility bill, either to the minimum bill threshold or until the banked net metering credits were fully used. Any remaining required utility bill, either at the minimum bill level, or in excess of the minimum bill, was assumed paid by the customer during that month. During months in which the calculated bill based on monthly consumption was below the minimum bill threshold, the utility customer was assumed to pay the minimum bill. The difference between the minimum bill paid and what the bill would have been without the minimum bill was carried forward for use in future months. Additionally, in months in which production resulted in a net export of power, net metering credits were calculated and any excess credits were similarly rolled over into the next monthly period. Minimum bill payments are assumed to be paid to the distribution utility and not passed on to electricity suppliers. From the perspective of the PV system owner, this does not affect project economics.

[57] https://www.nationalgridus.com/non_html/1114meco.pdf

[58] National Grid's R-1 rate is structured as an inclining block structure, with kWh consumption over 600kWh having a different tariff rate than consumption under 600kWh.

[59] https://www.nationalgridus.com/masselectric/non_html/MA_Residential_Table.pdf

[60] https://www.nationalgridus.com/masselectric/non_html/MA_Residential_Table.pdf

[61] 20-year average residential annual utility cost increase 1994-2013 from: http://www.eia.gov/electricity/data/state/avgprice_annual.xls

[62] These correspond to the current National Grid customer charge and 2.5, 6.25 and 12.5 times the customer charge value respectively.

4.1.6 Incentive Assumptions

Modeled PV systems were assumed to benefit from both the 30% federal residential renewable energy tax credit and the Massachusetts residential renewable energy income tax credit. Both these tax incentives were assumed to be fully monetized in April during the year after the installation of the system. Additionally, the modeled system benefited from SREC revenues over the first ten years of the system life. SRECs were assumed to be monetized at the SREC auction price floor with payments for 12 months of SRECs occurring once a year after the close of the auction.

4.1.7 Other Simplifying Assumptions

In order to isolate the potential effects of a minimum bill, a number of simplifying assumption were made in developing the model. For instance, random annual fluctuations in onsite load or PV system output were not modeled and instead a consistent annual onsite load and PV production pattern was used. Adding annual variations in production and consumption have the effect of altering minimum bill dynamics potentially creating more or less annual net metering credit carryover. Additionally, the model does not include ongoing costs associated with system operations and maintenance or potential future inverter replacement. The modeled system is installed on January 1st of 2015 and different system modeling start dates could affect early-year model outputs, system paybacks and rates of return. This simplified model also assumes that system owners are not monetizing cumulative excess generation through the Schedule Z credit transfer mechanism. The implications of this assumption are discussed later in this section. Finally, all utility bill components are assumed to escalate at the same rate, in reality market conditions and regulatory cases will cause these components to increase (or decrease) at different rates.

This analysis does not examine potential minimum bill dynamics on non-residential utility customers. Given the significant variation in customer loads and rate structures for non-residential utility customers, modeling a representative building that could provide generalized insights to the Task Force would be difficult. Additionally, minimum bills for commercial customers in other jurisdictions have typically been designed as non-bypassable demand charges, making them highly customized to the specific circumstance of each utility customer. This analysis also does not explore other unique residential cases such as seasonal second homes or community shared solar. In particular, the effects of minimum bills on community shared solar customers may be similar to the low-consumption case discussed in this section, although these similarities would likely only apply to certain community shared solar ownership models.

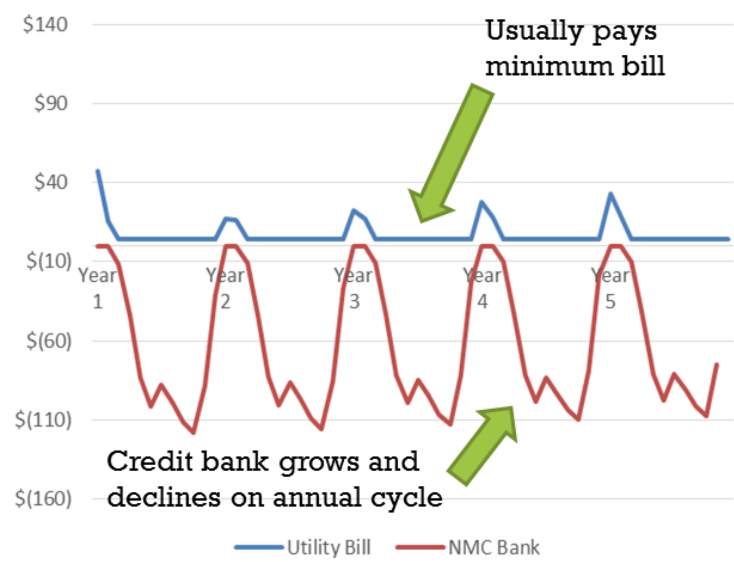
4.2 Modeling Results

4.2.1 Minimum Bill Dynamics

Each of the modeling parameters were run as part of 40 unique cases. Results showed that combinations of minimum bill levels, relative PV system sizes and total home consumption resulted in three distinct patterns. These three scenarios are illustrated below.

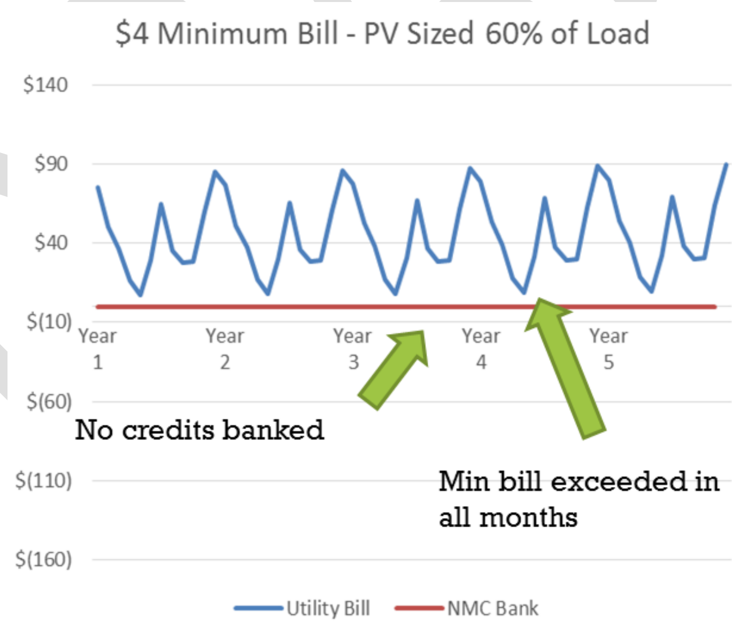
Under one scenario, illustrated in Figure 7 below, PV production leads to excess generation and banking of net metering credits during spring and summer periods. The blue line represents the customer's total utility bill for each month while the red line is the cumulative value of the customer's banked net metering credits. Under this scenario, the customer banks credits during the spring and summer months while credits are used in the late fall and winter months. This banking cycle occurs on an annual cycle and the customer does not build up a bank of credits that are carried forward for multiple years. This credit banking dynamic can result in customers paying the minimum bill during certain period of the year and paying higher bills during period of low PV production when the net metering credit bank has been full expended.

Figure 7. Five-Year Utility Bill Dynamics - $4 Minimum Bill – System Sized to 100 Percent of Average Consumption Load Case



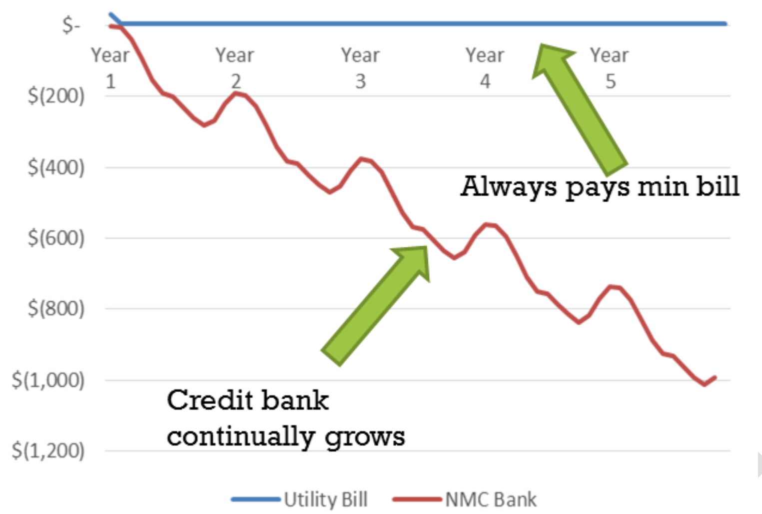
The second common bill dynamic is illustrated in Figure 88. Under this scenario, the PV system is sized smaller than the home's annual load. The customer's monthly bill rises and falls with seasonal changes in PV system production and onsite-load. Despite having a $4 minimum bill, under this case, the homeowner has no months in which a minimum bill is paid as that total utility bill always exceeds the minimum bill. Net metering credits are not banked under this scenario.

Figure 8. Five-Year Utility Bill Dynamics - $4 Minimum Bill – System Sized to 60 Percent of Average Consumption Load Case



The final common dynamic occurs when either the system is over-sized to the home load or when the minimum bill is high enough to cause the homeowner to always pay the minimum bill. Under this combination of factors, illustrated in Figure 9, the PV system continually generates net metering credits which are not monetized. As a result, the net metering credit bank grows over the life of the system. Notably, this is the same scenario customers with systems sized greater than their annual loads experience today even without a minimum bill. In the simplified modeling scenarios developed for this task, the net metering customer in this scenario does not take advantage of the opportunity to bilaterally sell excess net metering credits through the Schedule Z mechanism. A homeowner could gain a financial benefit from these unused credits by selling them to another utility customer, although the value at which these credits could be monetized in a bilateral net metering credit sale is unknown and would dictate the total financial loss, if any, resulting from this dynamic.

Figure 9. Utility Bill Dynamics - $4 Minimum Bill – System Sized to 120 Percent of Average Consumption Load Case



4.2.2 Effect of Minimum Bill on Total Utility Bill

To test the effect of different minimum bill levels on the overall utility bill paid by system owners, model runs were conducted for each of the system size cases and minimum bill levels. Both the average and low consumption home cases were modeled for each system size and minimum bill condition. First year, five-year and 20-year cumulative utility bills were calculated. These represent the total utility bills paid by customers including all customer charges, distribution charges and supply charges. The following tables show the results of this modeling. These results do not explicitly allocate utility bill costs between electricity suppliers and distribution utilities, however it is assumed that, during periods when a minimum bill is paid, those charges are paid exclusively to the distribution company without passing along funds to electric suppliers. A separate analysis is provided in the appendix of this report showing the total distribution portion of the customer bill for the average consumption case over the same time periods (see Figure 12).

Average Consumption Case

Year 1 Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	$23	$67	$133	$300	$600
1	$66	$88	$149	$314	$600
0.8	$291	$291	$291	$333	$605
0.6	$520	$520	$520	$520	$621

Years 1-5 Total Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	$23	$268	$636	$1,558	$3,116
1	$399	$403	$652	$1,571	$3,116
0.8	$1,557	$1,557	$1,557	$1,591	$3,120
0.6	$2,739	$2,739	$2,739	$2,739	$3,136

Years 1-20 Total Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	$23	$1,172	$2,897	$7,210	$14,421
1	$2,889	$2,889	$2,913	$7,224	$14,421
0.8	$8,063	$8,063	$8,063	$8,063	$14,425
0.6	$13,326	$13,326	$13,326	$13,326	$14,441

Low Consumption Case

Year 1 Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	$13	$57	$123	$300	$600
1	$57	$68	$131	$300	$600
0.8	$169	$169	$169	$304	$600
0.6	$284	$284	$284	$313	$600

Years 1-5 Total Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	$13	$259	$626	$1,558	$3,116
1	$324	$326	$634	$1,558	$3,116
0.8	$903	$903	$903	$1,562	$3,116
0.6	$1,494	$1,494	$1,494	$1,571	$3,116

Years 1-20 Total Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	$13	$1,163	$2,887	$7,210	$14,421
1	$2,021	$2,021	$2,895	$7,210	$14,421
0.8	$4,608	$4,608	$4,608	$7,215	$14,421
0.6	$7,240	$7,240	$7,240	$7,243	$14,421

These cases illustrate the potential dynamics of a minimum bill across a wide range of minimum bill thresholds. Under some conditions, total utility bills are unaffected by the addition of a minimum bill mechanism. In other cases, increasing minimum bill levels lead to significantly higher total utility bill collections. It is also notable that at higher minimum bill levels, customers pay the same cumulative utility bills regardless of the size of their PV systems. This effect is most pronounced in the $50 minimum bill categories where all customers, regardless of the size of their PV system or onsite load pay nearly the same utility bill.

Despite the increased costs for several of the cases with the implementation of a minimum bill compared to the no minimum bill case, customers in all cases see significant savings as a result of their solar installations regardless of the minimum bill. For reference, the modeled one-, five- and twenty-year total utility bills for the average-use customer without a solar PV system would be $1,214, $6,303 and $29,175 respectively. Each of these values is more than twice the modeled cumulative utility bill for the $50 minimum bill case.

This analysis only takes into account the total utility bill collections over the course of the analysis periods. As mentioned above, minimum bills can significantly change the timing of utility bill payments within an analysis period. For system size and load combinations where net metering credits are on an annual cycle in which credits are banked during periods of high production and fully utilized during months of low production, this would tend to decrease the monthly bill variance. The effect of this delay in monetizing system production is discussed in greater detail in the system financial analysis section of this report.

The same data is provided below in a different format that illustrates the relative increase in total utility bill for each system size and building consumption case relative to the no minimum bill case for that scenario.

Average Consumption Case

Year 1 Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	1.0	3.0	5.9	13.3	26.6
1	1.0	1.3	2.3	4.8	9.1
0.8	1.0	1.0	1.0	1.1	2.1
0.6	1.0	1.0	1.0	1.0	1.2

Years 1-5 Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	1.0	11.9	28.2	69.1	138.1
1	1.0	1.0	1.6	3.9	7.8
0.8	1.0	1.0	1.0	1.0	2.0
0.6	1.0	1.0	1.0	1.0	1.1

Years 1-20 Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	1.0	52.0	128.4	319.6	639.3
1	1.0	1.0	1.0	2.5	5.0
0.8	1.0	1.0	1.0	1.0	1.8
0.6	1.0	1.0	1.0	1.0	1.1

Low Consumption Case

Year 1 Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	1.0	4.3	9.3	22.6	45.2
1	1.0	1.2	2.3	5.3	10.6
0.8	1.0	1.0	1.0	1.8	3.5
0.6	1.0	1.0	1.0	1.1	2.1

Years 1-5 Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	1.0	19.5	47.2	117.3	155.8
1	1.0	1.0	2.0	4.8	9.2
0.8	1.0	1.0	1.0	1.7	3.4
0.6	1.0	1.0	1.0	1.1	2.1

Years 1-20 Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	1.0	87.6	217.4	543.0	721.1
1	1.0	1.0	1.4	3.6	6.9
0.8	1.0	1.0	1.0	1.6	3.1
0.6	1.0	1.0	1.0	1.0	2.0

As the data shows, the total change in utility bill over the time periods analyzed is highly dependent on the system size relative to total site load (PV/Load Ratio). For many of the scenarios, a minimum bill leads to no increase in total utility bills, while in others, the increase is potentially substantial on a percentage basis. Systems sized to produce the total annual onsite load and those sized to produce more than the total onsite load see an increased utility bill at all minimum bill levels in the 1 and 1-5 year timeframes. Alternatively, systems undersized to total load do not see any increase in total utility bill under the $4 and $10 minimum bill cases for all analysis timeframes.

The above table also illustrates the disproportionate effect of a fixed minimum bill on customers with lower consumption. For cases where a minimum bill leads to an increase in total utility bill, the relative increase is typically higher in the low consumption case compared to the high consumption case.[63] This effect could potentially be mitigated with a minimum bill structure that scales to the total on-site consumption. Under such a structure, homes with lower inherent consumption would be subject to lower minimum bill rates.

An important simplification in this analysis is that system owners that generate excess net metering credits for over-sized systems do not monetize those credits through bilateral net metering credit sales to other residents through the Schedule Z mechanism. System owners under this scenario could seek to monetize unused credits through this transfer mechanism. Therefore any increased utility revenue due to a minimum bill from an individual system owner may not lead to an overall utility-wide increase in bill collections as any unused net metering credits could be monetized by other utility customers, lowering their utility bills. Instead of increasing the net bill collections from net metering customers, a minimum bill may lead to an overall increase in the number of customers taking advantage of net metering (through the Schedule Z mechanism) with the total benefit available to any individual net metering customer being decreased.

[63] The effect is not seen in the Year 1 case due to the effects of the utility bill in the first analysis month. The timing of the start of the analysis, in January, creates a high first-month utility bill that influences this analysis.

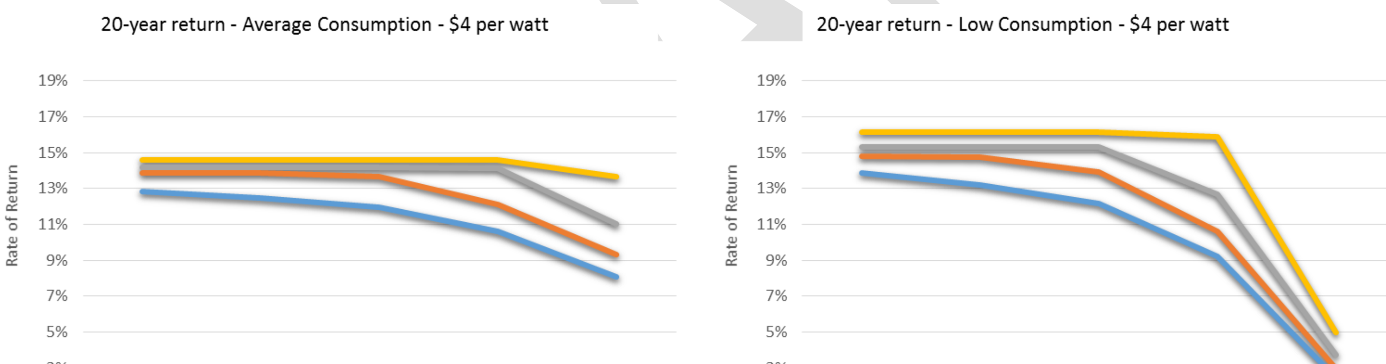
4.2.3 Effect of Minimum Bill on System Rates of Return and Simple Payback

Minimum bills can potentially affect PV system economics in several ways. For instance, a minimum bill can delay a system owner's ability to monetize the production of their PV system by several months, potentially lowering total system investment returns and increasing simple paybacks. Additionally, as noted previously, a minimum bill can also prevent a system owner from monetizing the entirety of their system's electricity production if the combination of system size and minimum bill threshold create a dynamic in which credits are continually banked.[64]

In order to determine the potential financial impacts of a minimum bill on system economics, 20-year internal rate of return[65] and simple payback (in years) were calculated for each of the modeling cases assuming $3, $4 and $5 dollar per watt installation costs. Both these financial metrics were included in the analysis as some residents may make decisions based on simple payback calculations while others may instead evaluate the systems lifetime rate of return. As mentioned above, this analysis included revenue streams from sources beyond utility bill savings including the 30% federal tax credit, the Massachusetts residential tax credit and SREC revenues. These components make up a signficant portion of a system's total financial value.

Figure 10 below show the 20-year rates of return for a system systems built for $4 per watt scaled to supply various onsite loads. As the figures illustrate, the range of potential system rates of returns is larger for the Low Consumption scenario, ranging from 16.1% in the no minimum bill case serving 60% of the annual home load to a 2.4% rate of return for the $50 minimum bill case where the system is sized to supply 120% of household annual load. The Average Consumption case range from 14.6% to 8.1% indicating that the minium bills have a smaller overal impact on system economics compared to the smaller household load scenarios.

Figure 10. Internal Rates of Return for Two Residential Modeling Cases



	$-	$4	$10	$25	$50
1.2	12.8%	12.5%	12.0%	10.6%	8.1%
1	13.9%	13.9%	13.7%	12.1%	9.3%
0.8	14.2%	14.2%	14.2%	14.1%	11.0%
0.6	14.6%	14.6%	14.6%	14.6%	13.7%

	$-	$4	$10	$25	$50
1.2	13.9%	13.2%	12.1%	9.2%	2.4%
1	14.8%	14.7%	13.9%	10.6%	3.0%
0.8	15.3%	15.3%	15.3%	12.7%	3.7%
0.6	16.1%	16.1%	16.1%	15.9%	5.0%

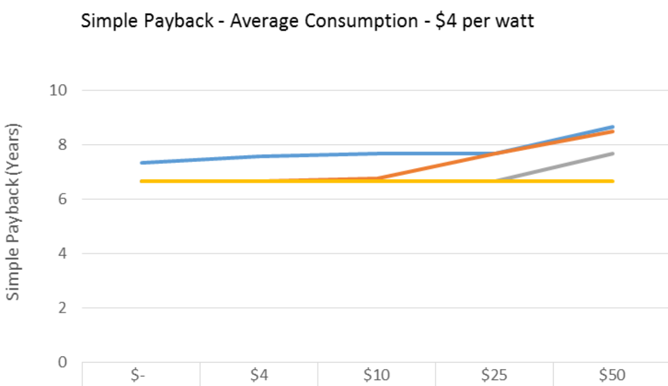
Figures 11 shows the simple payback for the same cases discussed above. As with the rate of return metric, the simple payback results show a wider potential range of paybacks for systems in the Low Consumption cases, ranging between

[64] As previously mentioned, this loss could be mitigated by selling unused credits to other utility customers.

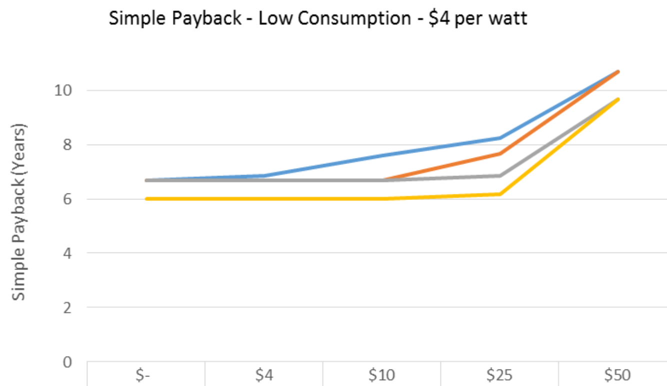
[65] The internal rate of return for the system is the equivalent to the discount rate at which the net present value of the total investment would be zero.

6.0 years and 10.7 years indicated a greater sensitivty to minimum bill effects for the lower consumption customer case.[66]

Figure 11. Simple Payback for Two Residential Modeling Cases



	$-	$4	$10	$25	$50
1.2	7.3	7.6	7.7	7.7	8.7
1	6.7	6.7	6.8	7.7	8.5
0.8	6.7	6.7	6.7	6.7	7.7
0.6	6.7	6.7	6.7	6.7	6.7



	$-	$4	$10	$25	$50
1.2	6.7	6.8	7.6	8.3	10.7
1	6.7	6.7	6.7	7.7	10.7
0.8	6.7	6.7	6.7	6.8	9.7
0.6	6.0	6.0	6.0	6.2	9.7

Additional scenarios for $3 and $5 dollar per watt installed costs are provided as an appendix to this report. In general the dynamics highlighted above are observed in these alternative cost cases.

As this analysis shows, the effects of minimum bills on project financial returns is highly dependent on the level of the minimum bill, the overall home load, the system cost, and the relative size of the system to the home load. Even within this simplified case, the range of effects from these parameters is substantial. As previously mentioned in this section, modeling results that assume different parameters would significantly change modeling outputs. Given the significant variation in potential system configurations, utility rates, financing and ownership structures, and system costs, it is difficult to generalize what the potential effects an undefined minimum bill policy could have on the development of the Massachusetts solar market. Additionally, any lost system value stream that results from the implementation of a minimum bill could potentially offset through adjustments from other incentive programs. If a minimum bill were to significantly decrease system economics, increased SREC market prices could potentially compensate for these losses.

4.2.4 Potential Impacts of a Minimum Bill on Virtual Net Metered Customers

The modeling presented in this section represents a PV system sited on a homeowner’s roof. Massachusetts has one of the most expansive virtual net metering regulations in the nation, allowing net metering credits from PV systems anywhere within a customer’s utility territory and ISO load zone to be used to reduce their utility bill. This has facilitated a number of community solar ownership models and has also supported the development of large ground-mounted systems that produce credits that serve multiple utility accounts of the same customer. The dynamics of a minimum bill related to these installation types were not modeled under this task, however the imposition of a minimum bill on customers using virtual net metering could substantially mirror the effects seen in the residential minimum bill model.

[66] The simple payback results show less overall variability in part because it is a less sensitive metric and because of the unevenness of system cash flow over the life of the system. For instance, SRECs are assumed to be monetized once a year after the SREC clearinghouse auction meaning that many of the modeled systems have the same simple payback values despite having differing overall cash flow profiles and internal rates of return.

Whether a system is net metered or virtually net metered would only make a limited impact on project economics under a minimum bill. For instance, customers that over-size their net metering contracts relative to both their annual consumption and the minimum bill threshold would be unable to fully benefit from their net metering credit purchases. For community solar installations serving low-use customers, the effects would likely be similar to those seen in the low-consumption case modeled above. From the perspective of PV system economics, having multiple net metering credit offtakers subject to a minimum bill could lead to a lower overall project size relative to the size of a system that could be developed without a minimum bill. For a large community solar installation, this effect could be overcome by increasing the number of participants taking advantage of the system, with each participant taking less of the systems overall production in order to avoid continually paying the minimum bill. Additionally, the effect of a minimum bill on the PV system exporting account, depending on the size of the minimum bill and the overall project size, could impact project economics.

For large PV systems serving a single customer with multiple meters, minimum bill impacts on system economics would depend on the number of utility meters served, the system size, the minimum bill level and the overall consumption the customer can offset via net metering. If the customer has sufficient annual consumption to fully utilize all the system output and can assign net metering credits in a manner that avoids the minimum bill on each account, project economics may be only modestly affected by the minimum bill. Alternatively, if a customer with multiple meters does not have sufficient load to monetize the entirety of their system's production without continually paying minimum bill levels, the economics of the project may be affected.

5 Conclusions

Minimum bill policies have been implemented in a limited number of jurisdictions across the country. These mechanisms have been used to ensure a minimum revenue is collected from all ratepayers within a rate class while also maintaining volumetric charges that promote energy conservation goals. Minimum bill policies have been implemented in some of the most active and growing solar markets in the United States, suggesting that these rates have not been a significant deterrent to solar market growth. Critically, the existing policies examined under this task have established minimum charges at or below $25 a month. The potential effects of higher minimum bills, such as those recently proposed in Hawaii, on solar market develop is unknown at this time.

Modeling of a hypothetical residential Massachusetts PV system shows that the potential effects of a minimum bill in the Commonwealth on both customer utility charges and PV system economics would be highly dependent on the specifics of how the minimum bill policy was defined and the specific parameters of the PV system. Under certain modeling conditions a minimum bill policy resulted in limited changes in total utility bill costs for the modeled system while under other conditions, a minimum bill was shown to significantly increase utility bill costs for PV system owners. Without a better defined minimum bill proposal, drawing conclusions about how a minimum bill could affect either utility cost recovery or PV market dynamics is not possible. Despite this, modeling results suggested that a minimum bill that was set at a fixed level for all customers within a rate class would be more likely to affect customers with lower consumption compared to those with higher annual consumption levels. Another key finding is that the size of a PV system relative to the annual load of a home significantly influences the overall impact of a minimum bill on system economics, with systems sized to meet more than the customer's annual load seeing the greatest impacts from a minimum bill. Finally, potential effects of a minimum bill on PV systems with more complex ownership structures or on commercial PV system were not modeled under this task. A minimum bill policy could potentially affect these market segments in ways not explored through the modeling completed in this section. However, as with simplified model presented under this task, any impacts on utility bills, PV system economics and overall market dynamics would likely be highly dependent on the specifics of the minimum bill policy and the individual system parameters.

Results Appendix

Figure 12. 20-Year IRR and Simple Payback Matrix for Average Consumption Case

	20-Year IRR						Simple Payback (Years)					
	PV/Load Ratio	$0	$4	$10	$25	$50	PV/Load Ratio	$0	$4	$10	$25	$50
$3 per Watt	1.2	18.7%	18.3%	17.7%	16.2%	13.3%	1.2	5.7	5.7	5.7	6.3	6.7
	1	20.1%	20.0%	19.7%	18.0%	14.8%	1	5.7	5.7	5.7	5.7	6.7
	0.8	20.5%	20.5%	20.5%	20.4%	16.8%	0.8	5.7	5.7	5.7	5.7	5.7
	0.6	21.1%	21.1%	21.1%	21.1%	20.0%	0.6	5.3	5.3	5.3	5.3	5.7
	PV/Load Ratio	$0	$4	$10	$25	$50	PV/Load Ratio	$0	$4	$10	$25	$50
$4 per Watt	1.2	12.8%	12.5%	12.0%	10.6%	8.1%	1.2	7.3	7.6	7.7	7.7	8.7
	1	13.9%	13.9%	13.7%	12.1%	9.3%	1	6.7	6.7	6.8	7.7	8.5
	0.8	14.2%	14.2%	14.2%	14.1%	11.0%	0.8	6.7	6.7	6.7	6.7	7.7
	0.6	14.6%	14.6%	14.6%	14.6%	13.7%	0.6	6.7	6.7	6.7	6.7	6.7
	PV/Load Ratio	$0	$4	$10	$25	$50	PV/Load Ratio	$0	$4	$10	$25	$50
$5 per Watt	1.2	9.0%	8.7%	8.2%	6.9%	4.6%	1.2	8.7	8.7	9.0	9.7	10.7
	1	9.9%	9.9%	9.7%	8.3%	5.7%	1	8.6	8.6	8.7	8.8	10.3
	0.8	10.1%	10.1%	10.1%	10.0%	7.3%	0.8	8.4	8.4	8.4	8.4	9.7
	0.6	10.4%	10.4%	10.4%	10.4%	9.6%	0.6	8.1	8.1	8.1	8.1	8.7

Figure 13. 20-Year IRR and Simple Payback Matrix for Low Consumption Case

20-Year IRR

	PV/Load Ratio	$0	$4	$10	$25	$50
$3 per Watt	1.2	20.2%	19.4%	18.2%	14.9%	7.8%
	1	21.4%	21.4%	20.4%	16.6%	8.5%
	0.8	22.2%	22.2%	22.2%	19.1%	9.4%
	0.6	22.6%	22.6%	22.6%	22.2%	10.2%
$4 per Watt	1.2	13.9%	13.2%	12.1%	9.2%	2.4%
	1	14.8%	14.7%	13.9%	10.6%	3.0%
	0.8	15.3%	15.3%	15.3%	12.7%	3.7%
	0.6	16.1%	16.1%	16.1%	15.9%	5.0%
$5 per Watt	1.2	9.8%	9.2%	8.2%	5.5%	-1.2%
	1	10.5%	10.5%	9.8%	6.8%	-0.7%
	0.8	10.9%	10.9%	10.9%	8.6%	-0.1%
	0.6	11.5%	11.5%	11.5%	11.3%	1.0%

Simple Payback (Years)

	PV/Load Ratio	$0	$4	$10	$25	$50
$3 per Watt	1.2	5.7	5.7	5.7	6.7	7.7
	1	5.2	5.2	5.6	5.7	7.7
	0.8	4.7	4.7	4.7	5.7	7.7
	0.6	4.7	4.7	4.7	4.7	6.7
$4 per Watt	1.2	6.7	6.8	7.6	8.3	10.7
	1	6.7	6.7	6.7	7.7	10.7
	0.8	6.7	6.7	6.7	6.8	9.7
	0.6	6.0	6.0	6.0	6.2	9.7
$5 per Watt	1.2	8.6	8.7	8.7	10.2	-
	1	7.8	7.9	8.6	9.7	-
	0.8	7.7	7.7	7.7	8.7	-
	0.6	7.7	7.7	7.7	7.7	11.7

Figure 14. Distribution Portion of Utility Bill for Average Consumption Case

Year 1 Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	$12	$56	$122	$300	$600
1	$56	$65	$129	$300	$600
0.8	$156	$156	$156	$301	$600
0.6	$262	$262	$262	$307	$600

Years 1-5 Total Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	$12	$257	$625	$1,558	$3,116
1	$314	$316	$632	$1,558	$3,116
0.8	$834	$834	$834	$1,558	$3,116
0.6	$1,377	$1,377	$1,377	$1,565	$3,116

Years 1-20 Total Utility Bill

PV/Load Ratio	$-	$4	$10	$25	$50
1.2	$12	$1,162	$2,886	$7,210	$14,421
1	$1,915	$1,915	$2,893	$7,210	$14,421
0.8	$4,249	$4,249	$4,249	$7,211	$14,421
0.6	$6,673	$6,673	$6,673	$7,218	$14,421

Appendix II Current Massachusetts Utility Rates

Massachusetts utility rates, including all customer charges, demand charges, program charges and basic service supply charges are published by each utility company as rates are updated. Given the complexity of the many rate structures offered by the state's four investor-owned utilities, those rate sheets are provided in the following links for reference:

National Grid: https://www.nationalgridus.com/non_html/1114nant.pdf

Eversource East (former NSTAR territories)

- Boston Edison: https://www.eversource.com/Content/docs/default-source/rates-tariffs/190.pdf?sfvrsn=4
- Cambridge Electric: https://www.eversource.com/Content/docs/default-source/rates-tariffs/290.pdf?sfvrsn=4
- Commonwealth Electric: https://www.eversource.com/Content/docs/default-source/rates-tariffs/390.pdf?sfvrsn=4

Eversource West (formerly WMECO): https://www.eversource.com/Content/docs/default-source/rates-tariffs/1052.pdf?sfvrsn=6

Unitil: http://unitil.com/sites/default/files/tariffs/E_dpu274_Summary_of_Rates_010115.pdf