A Financial Benefit-Cost Analysis of Different Community Solar Approaches in the Northeastern US

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ABSTRACT

Community solar farms (CSF) have the potential to expand solar access and improve financial viability compared to traditional residential and commercial solar options. The Cook County Community Solar Project created and made publicly available 26 benefit-cost analysis spreadsheets and associated white papers for 15 case study CSF locations in Illinois with proposed panel leasing financial models. We update these spreadsheets to reflect current federal incentives, fix some key errors, and compare the net present value, annual cash flow,

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return on investment, and simple payback period for all 26 panel leasing financial models; apply the panel leasing model to a Maine-based location; develop and apply to Maine three additional financial models: lease-to-own, panel purchase with developer, and grassroots "true ownership"; and provide a comparative analysis of the effects of federal and state incentives on CSF panel leasing in Maine and Illinois. Illinois panel lease results for subscribers, owners, and hosts, respectively, include net present values ($2019 thousands) of -$127 to $27, $6 to $450, -$490 to $473; return on investment of -53% to 295%, 8% to 117%, -44% to 474%; and simple payback period (years) of 0 to 20, 3.6 to 20, 0 to 20, (with system owner internal rate of return set at 10%). Respective Maine results include: $5 to $9, $4 to $201, $193 to $209; 84% to 262%, 26% to 207%, 116% to 309%; 0 to 8, 1 to 14, 0 to 3. Holding all else equal, higher electricity prices, a lower labor rate, and a 1:1 net metering bill credit policy yield greater subscriber and host (anchor subscriber) benefits for Maine than Illinois. Although the panel purchase model yields the greatest net present value (NPV) for subscriber and host in the Maine analysis, it yields the lowest developer NPV and requires a large upfront cost to subscribers that may limit participation to those with higher income. Therefore, we recommend the lease-to-own model for the Maine case study site, as it provides positive substantial NPV for all three stakeholder types without large upfront costs for subscribers and with a path to ownership.

KEYWORDS

Community Shared Solar Farms; Photovoltaic, Net Present Value; Benefit-Cost Analysis; Panel Leasing; Lease-to-own

1. Introduction[2]

Falling somewhere in scale between individual residential and utility scale solar photovoltaic systems, community solar farms (CSFs) have been posited as a complementary way to expand the solar market and encourage broader solar technology diffusion. Compared to residential solar, larger community solar arrays offer economies of scale and associated lower costs, more flexibility in siting for maximum solar resource, and a new opportunity for individuals who are unable or unwilling to install solar on their own property. A National Renewable Energy Laboratory (NREL) report estimates that nearly 50% of consumers and businesses are unable to host solar photovoltaic (PV) systems on their own property due to a number of factors, including the quality or position of their roof, whether or not they rent the property, and the high up-front costs of single-owner, rooftop systems, which tend to be more costly on a per-watt basis than commercial and industrial scale systems (SEIA 2020). Compared to larger utility-scale solar, CSFs have the potential to facilitate greater community engagement and learning and allow solar arrays to be sited closer to loads, although whether either happens in practice depends on how the market is regulated and incentivized.

[2] Abbreviations: ABP, Adjustable Block Program; ACTT, A Climate To Thrive; CCCSP, Cook County Community Solar Project; COM, commercial; CSBCT, Community Solar Business Case Tool; CSF, community solar farm; DG, distributed generation; DOE, Department of Energy; ILSFA, Illinois Solar for All; IRR, internal rate of return; ITC, investment tax credit; LD = legislative document; LLC, limited liability company; LMI, low-to-moderate income; LTO, lease-to-own; LTRRPP = Long-Term Renewable Resources Procurement Plan; MACRS, Modified Accelerated Cost Recovery System; MDI, Mount Desert Island; MPUC, Maine Public Utilities Commission; NPV, net present value; NREL, National Renewable Energy Laboratory; O&M, operation & maintenance; PBP, payback period; PL, panel lease; PLP, panel lease price; PP, panel purchase; PPA, power purchase agreement; PPP, panel purchase price; PV, photovoltaic; REC, renewable energy credit; RES, residential; RGGI, Regional Greenhouse Gas Initiative (RGGI), ROI, return on investment; RPS, renewable portfolio standard; SLP, site lease price; SS, small subscriber; TO, true ownership; VNM, virtual net metering (Tables 1- 5 include additional abbreviations unique to them, including 30 abbreviations for the 30 financial models considered in this paper)

CSFs are owned or leased by multiple people who do not necessarily own the property upon which the array sits and share some or all of the costs and benefits of the array (Farrell 2010). While NREL specifies three main types of CSF (utility- or third party-led, special purpose entity, and non-profit) (Coughlin et al. 2012; J. Heeter, Xu, and Fekete 2020), there are many more ways that a CSF can be structured from financial and organizational perspectives – in fact existing literature identifies twenty-three solar PV financing mechanisms that could be used to support CSFs (Appendix A). Several government reports and white papers describe effective design principles and best practices for successful solar policies and programs[3]; describe and categorize existing clean energy programs/case study projects[4]; and explore business models for distributed energy[5] or for utility-sponsored CSFs[6]. However, there are no published quantitative economic journal articles that compare different financial and organizational approaches to CSFs across different locations and policies in the US.

Emily McGavisk of West Monroe Partners and Vito Greco of Elevate Energy recently developed the Community Solar Business Case Tool (CSBCT) (McGavisk and Greco 2017) as part of the US Department of Energy (DOE)-funded Cook County Community Solar Project (CCCSP) ("Community Solar Case Study Sites" n.d.), which includes technical and financial analyses for fifteen potential case study projects in Cook County, Illinois. In addition to the publicly

[3] (Paulos 2017); (Mueller and Ronen 2015); (Passer 2017); (NREL n.d.); (GRID Alternatives and Vote Solar 2020a); (Campbell, Chung, and Venegas 2014); (Schroeder McConnell et al. 2016); (Haynes, Patterson, and Atkinson 2016); (Bovarnick and Banks 2014)

[4] (Paulos 2017); (Chace et al. 2018); (GRID Alternatives and Vote Solar 2020a); (Passer 2017); (Schroeder McConnell et al. 2016)

[5] (Chan, Ernst, and Newcomb 2016)(Passer 2017)(GRID Alternatives and Vote Solar 2020a)(Schroeder McConnell et al. 2016)

[6] (Chwastyk et al. 2018)

available, downloadable Excel-based CSBCT, the CCCSP also supplies detailed documentation for each site, including: a 2-page project synopsis; a site-specific technical analysis of solar energy system sizing and other specifications; a full case study report with major assumptions and results; and the CSBCT Excel files used to arrive at those results. Despite this rich set of information and data for each site, there is very little quantitative comparison across the 15 sites and 26 unique financial models generated by the CCCSP.

In addition, all CCCSP sites are, by design, in the same geographic area (Cook County, IL). Yet, community solar is growing rapidly across the country, with many groups, organizations, and businesses wondering how they can become involved. For example, the non-profit organization, A Climate To Thrive (ACTT), is working towards achieving energy independence by 2030 on Mount Desert Island (MDI), Maine. ACTT has implemented two CSFs already and is looking to add a third that can accommodate low-to-moderate income (LMI) residents ("A Climate to Thrive" n.d.). There are many other organizations like ACTT facing similar opportunities and challenges. This paper is a first step in producing the type of comparative quantitative economic analysis needed by ACTT and others to start the process of figuring out which CSF approach is most suitable for their needs. It builds on the CCCSP by providing comparisons across all 26 unique financial models produced by the CCCSP and adding four new models (that also use the CSBCT) for Mount Desert, Maine. The comparative results will help community solar stakeholders, including developers, participants (often called subscribers), hosts (people/institutions that own the site where the array is physically located and may play the role of an "anchor" commercial subscriber), and policy-makers understand the financial implications of different CSF approaches in different geographic locations and under different policies.

2.0 Background

Community solar began in Colorado in 2011, and has been increasing exponentially ever since (Watkins 2018). For example, between 2016 and 2019, community solar capacity more than quadrupled, (300MW to 1,387 MW (Becker 2019)). Currently, 40 states have at least one active CSF (total installed nationwide capacity: 2.1 GW), and 12 states, plus Washington D.C., have developed or are developing community solar programs targeting LMI accessibility (Becker 2019). Minnesota has the most installed community solar capacity in the US to-date (663 MW), the majority of which is utility-led and used by commercial (not residential) participants (EnergySage 2017; J. Heeter 2020). Massachusetts follows with over 400 MW of installed capacity (J. Heeter 2020) that is primarily third party developer-led, with greater emphasis on residential use (EnergySage 2017). Current US installed CSF capacity is projected to almost triple in the next five years, with the addition of 3.4 more GW (SEIA 2020).

CSFs require a site on which to put the solar array (the host), someone to pay for the installation of the array (the developer), someone to share in the ongoing costs and benefits of the array (the subscribers), and a mechanism through which subscribers can receive benefits of an array that is not on their own property (community/virtual net metering). Typically, a utility or third-party “developer” purchases/installs the CSF, sells or rents “shares” to multiple subscribers, and credits subscribers for their energy share on their electric bill. However, there is no standardized approach, meaning that each CSF can be managed or structured differently. Virtual net metering (VNM) is a bill crediting system that allows CSF participants to receive credits on their electric bill for excess energy production from their CSF share (Cook and Bird 2018; EnergySage 2019). Currently, 41 states have net metering programs for rooftop solar while only 14 states and Washington D.C. offer VNM for CSFs (Cook and Bird 2018; EnergySage 2019).

The first CSFs in both Maine and Illinois began operation in 2014 (J. Heeter 2020). In both states, as well as other states where electricity restructuring prevents utilities from owning generation, utility-sponsored CSFs are not a viable option. Third party developers offer advantages over special purpose entities or non-profit organizations, especially because of the complexities involved with limited liability companies (LLCs; one type of special purpose entity) and other co-ownership arrangements, as well as difficulties associated with potential non-profit owners taking advantage of tax incentives. However, state policy drives CSF development. While Maine has offered VNM for years, state laws requiring “ownership interest” (Table 1) and limiting the array to only 10 electric meters (9 participants plus one meter for the array itself) have essentially limited the maximum size of most Maine CSFs to 80 kW or less (J. Heeter 2020; ReVision Energy 2015). These policies created an incentive for people who can afford the upfront cost to try to develop CSFs through a grassroots approach but a disincentive for developers, who typically have the skills and capital to get a project off the ground, to be involved. Therefore, the 11 Maine CSFs that have been installed (J. Heeter 2020) have been developed mostly through collaborations between motivated citizens and/or organizations/municipalities and a regional solar installer, ReVision Energy (ReVision Energy 2019) under a “true ownership” financial arrangement (ReVision Energy 2020). Developer-led larger-scale lease-based CSFs have not yet taken hold in Maine.

Table 1 - Maine and Illinois Policy Comparison[1]

Factor	Maine pre-2020	Maine 2020	Illinois pre-2017	Illinois post-2017
Number of CSFs[2]	11	29	3	122
Total power capacity (MW)[b]	0.75	NS	1.1	221
Most common CSF type	Installer/Citizen-led; Municipal	Developer-led[3]	Rural electric coop	Developer-led[3]
CSF Laws & Regulations[4]	Ch. 313	Ch. 478, 312, 313-revised	220 ILCS 5/16-107.5, S.B. 2814	PA 99-0906; LTRRPP
Year laws & regs enacted	2009	2019-2020	2007-2008	2017-2020
CSF Program	CNEB	SDGP	NEM	ABP-CS; ILSFA-CS
State program target (MW)	N/A	250	N/A	678
Target date	N/A	7/1/24	N/A	5/31/21
Project limit (kW)	660	5,000	2,000	2,000
Subscriber interest allowed	Ownership only	Financial[5]	N/A	Financial[5]
NEM bill credit	Energy & Delivery		Energy Only	
Min LMI % power capacity[6]	0%	5% or 10%	N/A	0, 50, 100%
Max anchor sub % capacity	NS	70%[7]	N/A	40%
REC incentive ($2020/MWh)[8]	$7-$40	CB	CB	$36-122
REC delivery term (yr)	20	20	NS	15
Smart inverter rebate ($/kW-dc)	N/A	N/A	N/A	$250

[1]CSF = community solar farm; NS = Not Specified; Ch. = Chapter (of Law); ILCS = Illinois Compiled Statutes; S.B. = Senate Bill; PA = Public Act; LTRRPP = Long-Term Renewable Resources Procurement Plan; CNEB = Customer Net Energy Billing; SDGP = Shared Distributed Generation Procurement; NEM = Net Electricity Metering; ABP-CS = Adjustable Block Program for Community Solar; ILSFA-CS = Illinois Solar For All Low-Income Community Solar Initiative; N/A = Not Applicable; LMI = low-to-moderate income; REC = renewable energy credit; CB = competitive bid

[2]ME 2020: existing plus shared distributed generation projects (mostly solar) for which applications achieved bid offer status in Block 1 SDGP; IL post-2017: existing pre-2017 plus all projects with active contracts in the ABP-CS and ILSFA-CS

[3]Based on our interpretation & assessment of the laws & regs and (EnergySage, 2017)

[4](Illinois Power Agency (IPA) 2020; Maine Public Utilities Commission 2020; 2019a; 2019b; 2009; NC Clean Energy Technology Center 2017)

[5]Financial includes ownership as well as other financial arrangements (e.g., subscriptions)

[6]*For ME, it's 10% unless more than 50% of the subscriptions are allocated to a municipality or unit of municipal government; in which case, it drops to 5%, and in both cases, the % can be met by households or organizations serving households with LMI "if the subscriptions serve to directly reduce the electricity costs for the LMI households" (Maine Public Utilities Commission, 2019a); for IL, there is no minimum for the ABP, only for ILSFA and different ILSFA incentives at 50% or 100% low-income*

[7]*No anchor sub max in ME legislation, only a 70% limit on the share for a municipality/government (could possibly act as an anchor subscriber) (Maine Public Utilities Commission, 2019a)*

[8]*ME projects are eligible to sell RECs into the New England Power Pool competitive market, the Class I clearing price for which was $7/REC in 2018 and $40/REC in 2019 (Robers, 2019), although for projects that are part of the DG Procurement a REC price is determined through the competitive bidding process; IL range is for all ABP-CS & ILSFA-CS prices.*

However, Maine's 2019 Legislative Document (LD) 1711 removes the ownership interest and 10-meter limitations, sets a maximum system size of 5 MW, mandates 10% LMI power capacity, and creates a shared Distributed Generation (DG) Procurement process that includes CSFs (*An Act To Promote Solar Energy Projects and Distributed Generation Resources in Maine* 2019; Maine Public Utilities Commission 2019a; 2019b). The Maine Public Utilities Commission (MPUC) initiated Block 1 of the DG procurement in February 2020; however, in August 2020, the MPUC determined the procurement was "not competitive" due to a relatively small number of bidders (6 bidders for 18 projects), high bidding prices (>$0.19/kWh) compared to existing net energy billing contracts in the state ($0.120-0.145/kWh), interconnection agreement bottlenecks, and several other factors (including COVID-19). Therefore, there are not yet any new projects being developed under this new program in Maine, but 18 projects made it to the bid offer stage in the failed procurement. The MPUC will study the reasons for the non-competitive procurement more thoroughly and initiate a new procurement by May 2021. Although the MPUC has not released any details about the 18 shared DG projects that made it to the bid offer stage, the structure of the new solar policy and procurement process suggest these projects are likely to have a more developer-led approach compared to the more installer/citizen-led approach of the past, mainly due to larger allowable sizes, many complexities in the competitive bidding process, and the ability of developers to more easily access capital and tax incentives compared to citizen groups and non-profit organizations.

Illinois also appears to be headed in a developer-led CSF direction even though early projects were rural electric cooperatives (Table 1). In fact, the CCCSP analysis selected developer-led projects for 11 out of their 15 case studies due to favorable project financials and other factors. The CCCSP analysis was released in 2017, just as Illinois was adopting a comprehensive set of new solar incentives and policies, based on the 2017 Future Energy Jobs Act ("Future Energy Jobs Act" n.d.), which includes three main CSF provisions: 1) Adjustable Block Program (ABP) with a sub-program for CSFs; 2) Illinois Solar For All (ILSFA) Low-Income Community Solar Initiative; and 3) ILSFA Low-Income Community Solar Pilot Procurement. At the time of the CCCSP analysis, the Illinois Power Agency had not yet released its Long-Term Renewable Resources Procurement Plan (LTRRPP) (Illinois Power Agency (IPA) 2020) which specifies the exact nature of the ABP and ILSFA programs for CSFs: 1) ABP is for any CSF; ILSFA is only for CSFs that include at least 50% low-income participants (residential individuals or affordable housing owners), with an extra incentive for projects that are 100% low income (100% ownership can be achieved up to 6 years after the project is energized); 2) ILSFA includes higher incentive levels than ABP due to low-income requirements; 3) ABP requires an application fee but ILSFA does not; and 4) ILSFA requires documented partnerships between CSF developers and community-based organizations. Both the ABP and ILSFA include an "anchor subscriber" limitation of 1 anchor subscriber per project that takes up no more than 40% of nameplate capacity. The ILSFA prioritizes project selection for anchor subscribers that are “non-profit or public facility critical service providers and also the project host” (see p. 200 of (Illinois Power Agency (IPA) 2020). Both the ABP and ILSFA (as well as the Maine DG Procurement) include sub-programs for non-CSF solar projects as well; however, we focus solely on the CSF programs for this paper. Because the LTRRPP was not yet released when the CCCSP happened, the CCCSP analysis is based on anticipated rather than actual Illinois CSF policy changes and is not necessarily representative of current policy conditions.

Both Maine and Illinois incentivize CSFs through Renewable Energy Credits (RECs), which are delivered from the project to the transmission and distribution utility to satisfy state Renewable Portfolio Standard (RPS) requirements. Illinois’s ABP block schedule includes a specific total power capacity limit (5.5-52 MW; see p. 116 of (Illinois Power Agency (IPA) 2020)) and associated REC pricing that varies with individual project power capacity and utility territory group (Figure B1, Appendix B). The non-block ILSFA REC pricing (Figure B1, Appendix B) also varies with individual power capacity and utility territory and includes REC adders for small subscriber (SS, less than or equal to 25 kW) participation (+$10.88-11.17/MWh for 25-50% SS power capacity; +$21.77-22.34/MWh for >50% SS). The ILSFA Low-Income Community Solar Pilot Procurement is the exception as a competitive procurement program where the REC incentive is set through competitive bidding, not a pre-determined schedule (Illinois Power Agency (IPA) 2020). Competitive bidding is how Maine’s current DG procurement operates as well and how Illinois’s CSF policy used to operate prior to 2017. Prior to 2019, Maine CSFs could participate in the Regional Greenhouse Gas Initiative (RGGI) REC trading program through the New England Power Pool (“Elements of RGGI | RGGI, Inc.” n.d.), with competitive REC prices ranging from $7-$40/MWh in recent years (Robers 2019). While RGGI is still active, the shared

DG procurement offers Maine CSFs a more stable and predictable REC price through competitive bidding than RGGI provides. Both states require RECs to be delivered over a specific timeframe (20 yrs Maine; 15 yrs Illinois), but Illinois' REC payment schedule actually pays out the full REC incentive in the first five years after project energization (Illinois Power Agency (IPA) 2020).

The main purpose of our analysis is to compare publicly available CSF financial data to a set of new financial models developed for a Maine-based CSF. There are no published studies to-date that quantitatively compare the financial benefits and costs of CSFs across different financial models and geographies/policies. The CCCSP documentation is the most detailed and comprehensive quantitative CSF benefit-cost resource available, which is why we are building our Maine-based ACTT analysis upon it and making direct comparisons to it, in order to advance the literature and learning in this important area of research. However, it is beyond the scope of our study to re-do the CCCSP analysis based on the updated Illinois policy changes released in the Illinois Power Agency's April 2020 Final LTRRPP. Therefore, the Illinois results we present are not necessarily representative of current IL policy conditions but of anticipated state policy conditions at the time CCCSP conducted their analysis (2016-2017).

3.0 Methods

The CSBCT, produced by the CCCSP, is a spreadsheet-based financial model, freely downloadable in generic and Illinois-specific templates (McGavisk and Greco 2017). The CCCSP used a customized version (v1.21) of the Illinois-specific template to represent 26 distinct CSBCT financial models with 26 distinct CSBCT spreadsheets for 15 case study locations (1-3 spreadsheets per location;). The CCCSP selected one financial model for each case study to put forward as "proposed", with limited explanation about why the "proposed" financial model was selected over other models (i.e., higher return on investment, lower risk, and other case-specific challenges/priorities)("Community Solar Case Study Sites" n.d.). Instead of focusing just on the "proposed" financial models highlighted in the case study documentation, we downloaded and use all of the 26 distinct financial models in our comparative analysis because the focus of our analysis differs from that of the Cook County Community Solar Project. Where the CCCSP sought to select specific financial models for specific sites in Illinois, we are interested in comparing all existing financial models that are publicly available and include sufficient quantitative detail (the 26 Cook County case studies are the only ones we were able to find) with each other and also compare them to a new case study location in Maine. Through this lens, the 11 financial models the CCCSP did not select to go forward as "proposed" may be relevant to others interested in developing CSFs outside of Illinois, and especially to our Maine case study location.

First, we extracted input data and results from all 26 CCCSP spreadsheets (Table 2). Then we compared these models to 4 models we developed ourselves, in collaboration with ACTT and using the CSBCT as a basis, for Mount Desert, Maine (shaded rows at the bottom of Table 2). Upon further investigation, the CSBCT spreadsheets and documentation for #25-26 revealed that they are not actually CSFs but rather behind-the-meter DG for one customer (a theater). They are still included in our analysis because they are part of the CCCSP case study analysis, but they appear in italics and lighter font in Table 2 to distinguish them from the CSFs.

Table 2 - Summary of CSF Case Study Sites Analyzed

#	Code	Case Name	Location	Power (kW)	Host Site	Owner of System	Installation Type	Business Model
1	**PSD***	**Prairie State College - Developer**	Chicago Heights, IL	1,987	Public College	Developer	Ground Tracking + Carports	Lease
2	**PSH**	**Prairie State College - Host**	Chicago Heights, IL	1,987	Public College	Host (tax-exempt)	Ground Tracking + Carports	Lease
3	**AGH***	**Altgeld Gardens - Host**	Chicago, IL	1,989	Public Housing Development	Host (tax-exempt)	Ground Tracking	Lease
4	**AGD**	**Altgeld Gardens - Developer**	Chicago, IL	1,987	Public Housing Development	Developer	Ground Tracking	Lease
5	**MCD***	**Markham Courthouse - Developer**	Markham, IL	2,000	Public Courthouse	Developer	Rooftop + Carports	Lease
6	**MCH**	**Markham Courthouse - Host**	Markham, IL	2,000	Public Courthouse	Host (tax-exempt)	Rooftop + Carports	Lease
7	**CTAD***	**CTA Maintenance Facility - Developer**	Skokie, IL	1,900	Public Transit Authority	Developer	Rooftop + Carports	Lease
8	**CTAF**	**CTA Maintenance Facility - Flip**	Skokie, IL	1,900	Public Transit Authority	Developer/ Host*	Rooftop + Carports	Lease
9	**CTAH**	**CTA Maintenance Facility - Host**	Skokie, IL	1,900	Public Transit Authority	Host (tax-exempt)	Rooftop + Carports	Lease
10	**RED***	**Rich East High School - Developer**	Park Forest, IL	1,640	Public High School	Developer	Rooftop + Carports	Lease
11	**DPD***	**Des-Plaines Lake Landfill - Developer**	Des Plaines, IL	1,420	Nonprofit Landfill	Developer	Ground	Lease
12	**DPF**	**Des-Plaines Lake Landfill - Flip**	Des Plaines, IL	1,420	Nonprofit Landfill	Developer/ Host*	Ground	Lease
13	**DPH**	**Des-Plaines Lake Landfill - Host**	Des Plaines, IL	1,420	Nonprofit Landfill	Host (tax-exempt)	Ground	Lease

#	Code	Case Name	Location	Power (kW)	Host Site	Owner of System	Installation Type	Business Model
14	**UAL**	**UAL Data Center**	Glenview, IL	1,410	Private Corporate Campus	Developer	Rooftop	Lease
15	**TAFT**	**Taft High School**	Chicago, IL	600	Public High School	Developer	Rooftop	Lease
16	**HACC***	**Housing Authority of Cook County**	Chicago Heights, IL	562	Public Housing Site	Developer	Ground Tracking	Lease
17	**OLPH***	**Our Lady of Perpetual Help**	Glenview, IL	534	Nonprofit House of Worship	Developer	Rooftop + Carports	Lease
18	**WAR***	**Warren Park Field House**	Chicago, IL	534	Public Park	Developer	Rooftop + Carports	Lease
19	**RIBH***	**Rockwell Industrial Building - Host**	Chicago, IL	470	Private Industrial property	Host (private)	Rooftop	Lease
20	**RIBD**	**Rockwell Industrial Building - Developer**	Chicago, IL	470	Private Industrial property	Developer	Rooftop	Lease
21	**KIBH***	**Knox Industrial Building - Host**	Chicago, IL	279	Private Industrial building	Host (private)	Rooftop	Lease
22	**KIBD**	**Knox Industrial Building - Developer**	Chicago, IL	279	Private Industrial building	Developer	Rooftop	Lease
23	**HAH***	**Hill Arboretum Apartments - Host**	Evanston, IL	127	Nonprofit multifamily affordable housing	Host (tax-exempt)	Rooftop	Lease
24	**HAD**	**Hill Arboretum Apartments - Developer**	Evanston, IL	127	Nonprofit multifamily affordable housing	Developer	Rooftop	Lease
25	***72PA****	***7200 S Kimbark - Developer PPA***	*Chicago, IL*	*45*	*Private Theater Studios*	*Developer - PPA*	*Rooftop*	*Lease*

#	Code	Case Name	Location	Power (kW)	Host Site	Owner of System	Installation Type	Business Model
26	***72H***	***7200 S Kimbark - Host***	*Chicago, IL*	*45*	*Private Theater Studios*	*Host (Private)*	*Rooftop*	*Lease*
27	**MDL**	**Mount Desert Lease**	Mount Desert, ME	700	TBD (Private)	Developer	Ground Tracking	Lease
28	**MDLO**	**Mount Desert Lease-to-Own**	Mount Desert, ME	700	TBD (Private)	Developer	Ground Tracking	Custom Lease-to-Own
29	**MDP**	**Mount Desert Purchase**	Mount Desert, ME	700	TBD (Private)	Developer	Ground Tracking	Purchase
30	**MDG**	**Mount Desert Grassroots**	Mount Desert, ME	700	TBD (Private)	Developer	Ground Tracking	Custom Purchase

**CCSP performed more than one analysis for this site, and this was the financial model selected by them to go forward for more detailed documentation (e.g., synopsis, case study, and solar design white papers) and ultimate recommendation. #25-26 are not CSFs – they are behind-the-meter distributed generation; TBD = to-be-determined; shaded cells identify cases we created for Maine, using the UAL (#14) spreadsheet as a starting point.*

The CSBCT calculates net present value (NPV), internal rate of return (IRR), simple (not discounted) payback period (PBP), and return on investment (ROI) for each project stakeholder (developer, host, and subscriber). NPV offers the primary means by which to analyze a proposed project's financial desirability; generally, a project is accepted if it yields a positive NPV and rejected otherwise. As the estimation of NPV involves revenues and expenses that occur in the future, calculations must consider the time value of money. Because of inflation and the opportunity cost associated with lost earnings that could have been made through other investments, money in the future is worth less than money in the present. This adjustment is achieved through a discount rate. The NPV of a project is thus calculated as the sum of its discounted cash flows over the lifetime of the project (Equation 1). The CSBCT applies Excel's built-in NPV function to a series of annual cash flows. In the cash flow for a solar

PV project, the upfront purchase price represents the majority of the cost. Figure 1 presents the installed cost per watt identified by the CCCSP based on the very detailed site assessment and solar design engineering assessment they did for each site. That type of detailed analysis is beyond the scope for the Maine case study location; instead, we estimated the installed cost based on the average cost of installed solar for Maine in April 2020 (SolarReviews 2020). ACTT estimated the site/land preparation cost based on their prior CSF experience. The CSBCT cash flow analysis assumes the upfront installation expense occurs in year zero, as a lump sum payment without a loan (the CSBCT has options for user-defined loan parameters but does not use these for the 15 case studies, so for consistency, and based on ACTT preference, neither do we in our Panel Lease and Lease-to-Own models (Sections 3.1 and 3.3, respectively)). Meanwhile, O&M and administrative costs, as well as revenue (electric bill credits for subscribers; subscriber payments and tax incentives for developers; site lease payments for hosts) generated by the system over its lifetime, are discounted.

$$NPV = -C_o + \sum_{t=1}^{T} \frac{b_t - c_t}{(1+d)^t} \qquad (1)$$

where C_o = initial investment cost; T = total project lifetime; b_t = annual benefits for year t; c_t = annual costs for year t; d = discount rate.

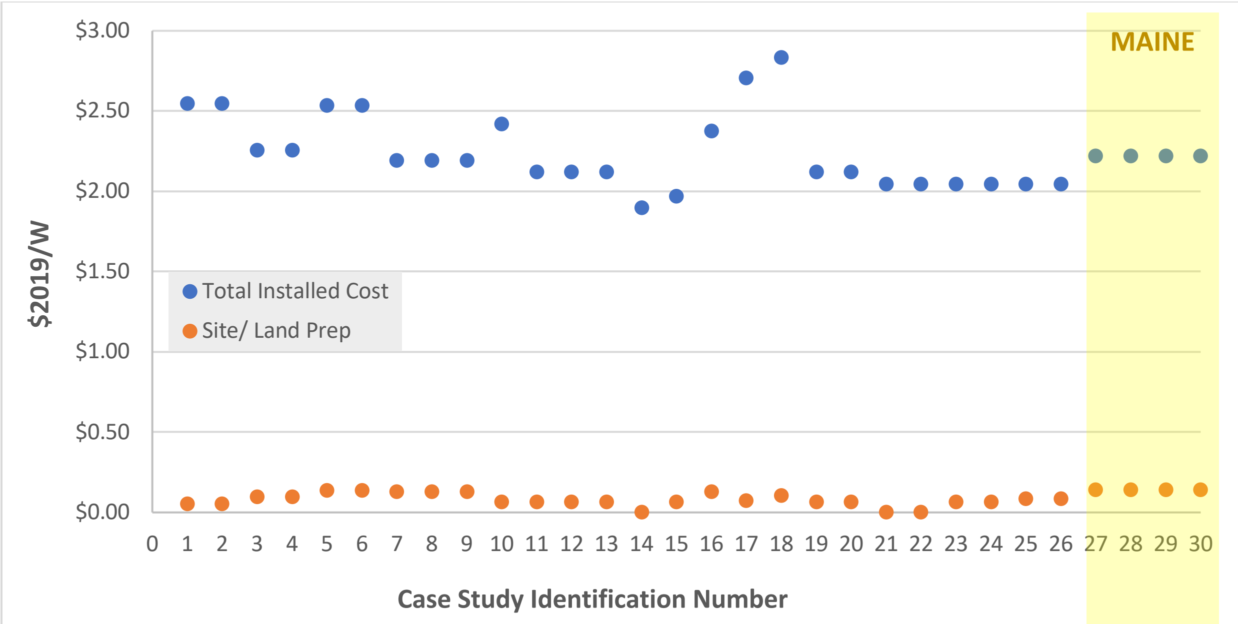

Figure 1 – Upfront cost of solar energy system. *IL data from CCCSP case study spreadsheets ("Community Solar Case Study Sites" n.d.). Maine installed cost from (SolarReviews 2020) and site/land prep cost specified by ACTT.*

The IRR is the discount rate at which the NPV equals zero. It provides a signal about how sensitive a project might be to discounting; i.e., how far over the line the benefits are from the costs – the higher the IRR the better. The CSBCT calculates the IRR using Excel's IRR function. Simple payback period refers to the number of years necessary to recoup the initial upfront payment through revenue. "Simple" refers to the fact that future cash flows are not discounted to reflect time value of money. The discounted payback period is the year in which the cumulative present value of the cash flow becomes positive. The CSBCT only identifies the simple payback period in the cash flow analysis, likely because it is the more common measure in solar decision-making. Return on investment is simply the ratio of total project benefits (over the project lifetime – 25 years in our case) divided by project costs (not discounted).

The CSBCT assumes $15/kW/yr for O&M costs (Table 3) and includes an entire sheet of detailed Admin & Transaction Costs, including upfront year 0 administrative costs - marketing &

communications, customer acquisition setup, outreach setup, and admin setup - as well as annual outreach, sales, sign-up transaction, customer service, and billing admin transactional costs. Since the 26 CCCSP spreadsheets are publicly available, and the Admin & Transaction Costs spreadsheet includes many inputs and calculations, we do not repeat all of them here. However, three important user-defined inputs to all of these calculations, for which we needed to make decisions for Maine, include the labor rate, labor escalator, and a selection of “Easy”, “Moderate”, or “Difficult” for Subscriber Acquisition Difficulty (Tables 3-4). For the latter, selecting Difficult increases (relative to Easy): the labor hours for marketing materials, media buy, and website; outreach, sales, and sign-up hours per subscriber; percent of subscribers calling per month; hours per call; billing setup hours per month; and individual subscriber billing hours. We selected all parameter values presented in Table 3 to be consistent with the CCCSP cases, except: ACTT specified the anchor panel percentage, and we used Maine-specific values for annual energy & demand cost increase (SUNMetrix 2020), labor rate (US Bureau of Labor Statistics 2019), monthly electricity generation profiles (“PVWatts Calculator” n.d.), residential and commercial subscriber bill credit rates (U.S. Energy Information Administration 2020), and state/local incentives (there are none, except for RECs).

Table 3 - Model Input Parameters Common to All Cases

Parameter	Illinois	Maine
Panel Size (W)[1]	325	
Years to full subscription[2]	1	
System Losses (%) – see Appendix C	14% to 19%	
Inverter Efficiency (%) – see Appendix C	97% to 99%	
% panels subscribed by anchor (COMMERCIAL)[3]	40%	20%
Annual Subscriber Retirement/Acquisition Rate[4]	1.5%	
Annual Energy & Demand Cost Increase	2.78%	1.64%
Project Lifetime (years)	25	
Subscriber NPV Discount Rate	10%	
Developer NPV Discount Rate[5]	8%	
Percent of Costs Financed (Developer)	0	
Interest Rate (Developer)	0	
Financing Term (yrs) (Developer)	0	
Site Purchase & Removal Costs ($2019)	0	
O&M Costs ($2019/kW-yr)	$15	
Federal ITC (%)	26%	
Smart Inverter Rebate ($2019/W)	$0.25	$0.00
State/Local Lump Sum Incentive (% system cost)	26% (tax-exempt only)	0%
Subscriber Subsidy (% of PLP)[6]	50%	50%
REC VALUE ($2019/MWh)	Varies[10]	$40[11]
REC Lifetime (years)	15	20
REC Payout Schedule (years)[7]	5	20
Tax Rate for MACRS Depreciation (%)	21%	
Salvage Value (% of system cost)	0	
Labor Rate for Acquisition Difficulty ($2019/hr)	$53	$35
Labor Escalator (%)	3%	
RESIDENTIAL Bill Credit Rate Yr 1 ($2019/kWh)[8]	$0.06	$0.17
COMMERCIAL Bill Credit Rate Yr 1 ($2019/kWh)[9]	$0.04	$0.15

Exceptions: *[1]UAL, MCD, MCH (310); [2]72PA and 72H (0); [3]20% for RIBH, RIBD; 100% for 72PA, 72H; 0% for MDG; [4]0% for CTAF, DPD, DPF, DPH, MDP, MDG; [5]MDG (10%); [6]DPD, DPF, DPH (0%) – also, there is no Maine subscriber subsidy; however, the CSBCT allows the user to easily model unsubsidized and subsidized subscribers together, so we include this subsidy for comparative purposes with the IL cases in case ME considers such a subsidy in the future; [7]72PA and 72H (1); [8]DPD, DPF, DPH, RIBH, RIBD, KIBH, KIBD ($0.04)' [9]72PA ($0.07), 72H ($0.09)*
[10]$45 (1-2 MW); $50 (0.5-1 MW); $52 (0.25-0.5 MW); $73 (<0.25 MW)
[11](Robers 2019)

Table 4 - Case-Specific Model Input Data

#	Code	P (MW)	CF (%)	E (MWh/y)	RES PLP ($2019/ p-mo)	COM PLP ($2019/ p-mo)	SLP ($2019/y)	RES PPS	# RES Sub[1]	Subscriber Acquisition Difficulty
1	PSD	2.0	15%	2,664	$3.12	$1.86	$7,989	20	183	Moderate
2	PSH	2.0	15%	2,664	$4.83	$2.88	$0	20	183	Moderate
3	AGH	2.0	17%	2,901	$3.20	$1.91	$0	20	184	Moderate
4	AGD	2.0	17%	2,901	$2.44	$1.46	$7,989	15	245	Difficult
5	MCD	2.0	15%	2,577	$3.24	$1.93	$6,817	15	258	Moderate
6	MCH	2.0	15%	2,577	$5.08	$3.03	$0	15	258	Moderate
7	CTAD	1.9	14%	2,379	$2.79	$1.66	$5,326	20	175	Moderate
8	CTAF	1.9	14%	2,379	$4.88	$2.91	$5,326	20	175	Moderate
9	CTAH	1.9	14%	2,379	$4.26	$0.00	$0	20	175	Moderate
10	RED	1.6	14%	2,014	$3.14	$1.87	$6,391	20	151	Moderate
11	DPD	1.4	15%	1,921	$1.67	$1.67	$6,391	874	3	Moderate
12	DPF	1.4	15%	1,921	$2.84	$2.84	$6,391	874	3	Moderate
13	DPH	1.4	15%	1,921	$3.06	$0.00	$0	728	3	Easy
14	UAL	1.4	15%	1,789	$1.68	$1.00	$6,391	20	136	Moderate
15	TAFT	0.6	14%	754	$2.61	$0.00	$4,261	15	74	Difficult
16	HACC	0.6	17%	839	$2.85	$1.70	$7,989	15	69	Difficult
17	OLPH	0.5	15%	680	$3.77	$0.00	$0	25	39	Easy
18	WAR	0.5	14%	638	$3.57	$2.13	$2,130	20	49	Easy
19	RIBH	0.5	15%	619	$1.36	$1.36	$0	289	4	Easy
20	RIBD	0.5	15%	619	$1.54	$1.54	$1,997	289	4	Easy
21	KIBH	0.3	14%	353	$1.13	$1.13	$0	429	1	Moderate
22	KIBD	0.3	14%	353	$1.43	$1.43	$1,278	258	1	Easy
23	HAH	0.1	14%	159	$0.86	$0.51	$0	15	16	Easy
24	HAD	0.1	14%	159	$0.70	$0.42	$1,278	15	16	Easy
25	72PA	0.1	11%	54	$1.82	$2.26	$0	0	0	Easy
26	72H	0.1	11%	54	$1.52	$0.00	$0	0	0	Easy
27	MDL	0.7	15%	1,015	$4.35	$3.87	$5,196	15	115	Moderate
28	MDLO	0.7	17%	1,015	$3.90	$3.47	$0	15	115	Moderate
29	MDP[2]	0.7	17%	1,015	$384	$342	$0	15	115	Moderate
30	MDG	0.7	17%	1,015	$769	$769	$0	15	115	Moderate

[1]Model output, not input
[2]Panel lease prices are actually panel purchase prices (one-time, not monthly)
P = power; CF = annual capacity factor; E = annual electricity generation; RES = residential; PLP = panel lease (or purchase) price); COM = commercial; p = panel; mo = month; SLP = site lease price; PPS = panels per subscriber; Sub = subscribers

We made the following changes to the 26 CCCSP case study spreadsheets: 1) updated federal incentives – changed the investment tax credit (ITC) and associated State/Local Lump Sum Incentive for tax exempt entities from 30% to 26% (interestingly the State/Local Lump Sum Incentive for #6 was originally set at 40% not 30% with no documentation for the change) and the Modified Accelerated Cost Recovery System (MACRS) federal corporate tax rate for depreciation from 35% to 21% ("DSIRE" n.d.; Tax Policy Center 2020); 2) fixed an error we found in the Host NPV calculation where the NPV equation was pulling in the capacity factor (in 24 spreadsheets) and random blank cells (in the 2 tax equity spreadsheets – Section 3.1) as the discount rate instead of the proper discount rate from the Inputs tab; 3) fixed an error in 16 out of 26 spreadsheets where the annual outreach cost calculation (Admin & Transaction Costs sheet) was pulling a blank cell as input instead of the annual subscriber gain (number of subscribers added per year); 4) updated the commercial panel lease price (COM PLP) to be consistent with the calculation we describe in Section 3.1 (except #11-12 and 19-22, which had residential (RES) PLP = COM PLP; #9, 13, 15, 17, 26 which had COM PLP = 0; #25, which had COM PLP > COM PLP – for that one we calculated the COM PLP by multiplying the RES PLP by the original ratio of COM PLP to RES PLP); 5) ran the Excel Goal Seek function for a target 10% developer IRR as described in Section 3.1 because the error fixes we did and the updated tax incentives changed the results (exceptions: #72H – Goal Seek led to negative PLP, so kept as-is; #30 – IRR for all stakeholders already greater than 10% so no need to decrease it). Although we have the updated ABP and ILSFA REC schedule (Figure B1; Appendix B) and other details in the LTRRPP, it is beyond the scope of our analysis to anticipate how the Illinois Power Agency would interpret CCCSP case study-specific details in awarding ABP versus ILSFA REC pricing (and adders) for each CCCSP case study, or determine how the specific LTRRPP wording of incentives and rules would change the nature of and quantitative inputs for similar state-level incentives assumed by the CCCSP. Therefore, we did not make any adjustments to state-specific IL incentives in the 26 CCCSP spreadsheets.

3.1 Panel Lease (PL) Model

The CSBCT provides two built-in financial modeling options: Panel Lease (PL) and Panel Purchase (PP), between which the user can toggle via a drop-down menu on the Inputs spreadsheet. The CCCSP selected the PL model for all 26 case study spreadsheets. The PL model: 1) applies the system installation price (equipment and labor), any upfront land and Admin & Transaction costs, revenue from the federal ITC and any upfront state/local incentives, as well as any loans, to the "developer" cash flow in Year 0; 2) applies any ongoing land lease, annual O&M and administrative & transaction costs, loan payments, and federal depreciation (5-yr MACRS), any annual state/local incentives, subscriber payments, unsubscribed energy payments and salvage value benefit to the developer cash flow in Years 1-25, as applicable (for example, MACRS only applies to Years 1-6 and loan terms are usually shorter than the 25-yr lifetime); 3) includes separate cash flow sections for the project host (anchor commercial subscriber) and residential subscribers (institutional/commercial in limited cases) that each include zero costs or benefits in Year 0, and in Years 1-25 as applicable: the annual cost of leasing the panels from the developer, annual land lease revenue from the developer's payments (host only), and annual bill credits (at the commercial net metering electricity rate for the host and at the residential rate for the residential subscribers (Figure 2)) based on an electricity generation profile entered by the user on the Generation spreadsheet; and 4) a separate cash flow for subsidized residential subscribers, which is the same as the other residential subscriber cash flow but with an additional row for annual subscriber subsidy payments (Table 3). The CCCSP used a target system owner IRR of 10% to guide the selection of the panel lease price (Table 4; Figure 2) in their 26 case study spreadsheets (Burciaga 2017). In order to stay consistent with the CCCSP analysis, we selected the residential panel lease and panel purchase prices for cases 27-29 (Table 4; Figure 2) and the revised 26 CCCSP spreadsheets, by using Excel's Goal Seek function, and finding the price that resulted in a 10% IRR for the system owner. We added a calculation to formally link the residential and anchor subscriber panel lease/purchase prices in order to use Goal Seek: the anchor price is calculated as the residential price times the ratio of the commercial to residential bill credit rate (with CCCSP exceptions noted in Section 3.0).

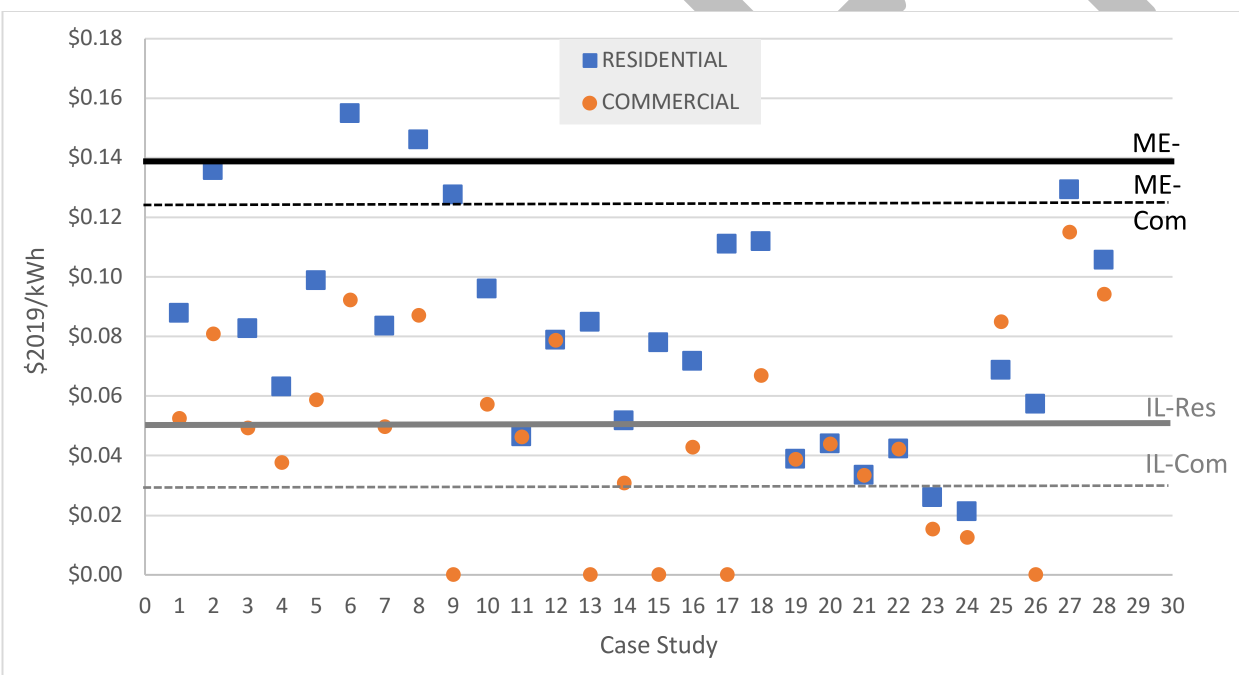

Figure 2 – Residential (Res) and commercial (Com) panel lease prices (scatterplot) and reference bill credit rates offered by the utility (horizontal lines). *The panel purchase prices for #29 ($10.41/kWh, $9.25/kWh) and #30 ($20.81/kWh) are not shown because of the scale.*

We used the CCCSP spreadsheet for the United Airlines Data Center (UAL #14, Table 2) as our basis for creating the Maine PL model (#27, Table 2). We entered the power capacity selected by ACTT (700 kW) and CSF location (Mount Desert, Maine), along with the average ground tracking system losses and inverter efficiency from the CCCSP cases (Appendix C) into NREL's PVWatts online calculator to obtain the monthly ground tracking PV electricity generation profile needed for the CSBCT spreadsheet (US National Renewable Energy Laboratory (NREL) n.d.). We selected the site lease price (SLP) to be the average of the SLP from the Cook County cases (Table 4). The electricity bill credit rates for Illinois are much lower than for Maine (Figure 2) because the Illinois net metering policy only credits the energy charge and not the delivery charge (Table 3). Maine has higher electricity prices than Illinois, and Maine's net metering policy credits the full delivered electricity rate, thereby increasing the viable panel lease/purchase price.

The 26 CCCSP spreadsheets include three "flavors" of the PL model: developer-owned (14/26 spreadsheets), host-owned (9/26 spreadsheets, of which 6 include tax-exempt hosts), and tax equity flip (2/26 spreadsheets). The host-owned spreadsheets have the same format as the developer-owned spreadsheets, except that for the tax-exempt hosts, the CCCSP made a drop-down input selection for "tax-exempt entity", which sets the ITC and MACRS federal tax incentives to zero and turns on the State/Local Lump Sum Incentive (Table 3), essentially assuming the tax-exempt entity will receive the same value as the ITC through the state incentive, but not receive the MACRS incentive. In the host-owned cases, both the developer and host cash flows are attributed to the host, but they are not integrated (i.e., the model provides separate NPV, IRR, PBP, ROI calculations for the host in the system owner and anchor subscriber roles. The two tax equity flip spreadsheets include a "business case" cash flow that includes all system owner costs and benefits over the project lifetime and then splits that all-inclusive business case into two separate system owner cash flows, one for the developer who will only be in the project for the tax equity portion of the project lifetime (i.e., just until the ITC and MACRS benefits have been paid out in year 6) and the other for the non-profit host who acts as anchor subscriber for the first 6 years of the project and then takes on the system owner role in year 7, until the end of the cash flow period. Neither the tax equity developer nor the host-owner take out a loan at any point, and there is no lump sum payment or fee when ownership is transferred from tax equity developer to non-profit host. There is not a lot of information in the CCCSP case study documentation about either of the two tax equity models, nor why they were not selected as “proposed” by the CCCSP, despite having higher host NPVs than the proposed developer-owned models; although, the CTAF (#8) case study documentation does say that the developer-owned model yielded a higher IRR for the developer than the equity model. Due the lack of documentation for the equity models, the limited use of them in the CCCSP case studies we are using in our analysis, the many different ways tax equity models can be structured, and the many complexities associated with them (Heightley, Marples, and Sherlock 2019; Cockerham 2018), developing a Maine-based tax equity model was beyond the scope of our analysis.

3.2 Panel Purchase (PP) Model

If the user selects Panel Purchase in the drop-down menu on the Inputs sheet, the following changes occur: 1) the developer cash flow receives the lump sum anchor and residential subscriber payments in Years 0 and 1, respectively, instead of annual subscriber payments in Years 1-25; 2) the host (anchor subscriber) cash flow incurs a lump sum cost in Year 1, which does not match with the timeline of the developer receiving that revenue (see #1); and 3) a 5-yr loan appears in the anchor and residential subscribers’ cash flows, with revenue experienced in Year 1 and payments incurred during years 2-6, for 50% of the upfront cost to the residential subscriber (for the anchor subscriber as well, which appears to be a mistake – should be 50% of the cost to the anchor subscriber for the anchor subscriber), financed at an interest rate of 8%.

We created our Maine PP model using the Maine PL spreadsheet we had created from the UAL spreadsheet. After toggling from Panel Lease to Panel Purchase on the Inputs sheet, we fixed the errors identified in #2 and 3 in the previous paragraph by moving the revenue to the developer from the host to Year 1 instead of Year 0 and applying the correct panel purchase cost for the loan calculation in the host cash flow. Next, it occurred to us that if the developer is receiving all of the project revenue other than RECs (lump sum subscriber panel purchase payments and federal ITC in Year 1 and MACRS in Years 1-6) in the first 6 years of the project but experiencing site lease, O&M, and Admin & Transaction costs in Years 1-25, there is no incentive for the developer to stay with the project after Year 6. Therefore, we made some changes to share the O&M, site lease, and Admin & Transaction costs across the subscribers: 1) added annual O&M and Admin & Transaction costs times 1.1 (to provide a guaranteed 10% profit for the developer on the annual costs after the panel purchase price has been paid) to the anchor and residential subscriber cash flows in an amount proportional to each subscriber's share of the power capacity of the array and added these costs as revenues in the developer cash flow; and 2) divided the annual site lease payments to the host by the number of subscribers and moved these payments from the developer cash flow to the residential subscriber cash flow. These changes caused the developer to have a positive cash flow beyond Year 6, where in the previous version of the CSBCT Panel Purchasing model, the developer had experienced negative net cash flows starting in year 7, after the MACRS tax benefit was all paid out. Finally, we set the annual subscriber retirement/acquisition rate to zero because we assume the same group of subscribers will stay with the project for its lifetime – this has the effect of removing the annual Year 1-25 outreach, sales, and sign-up transaction administrative costs (but keeping the customer service and billing annual costs).

3.3 Lease-To-Own (LTO) Model

We used the PL model we had created for Maine (Section 3.1) as a basis to create a 3rd financial model not yet included in the CSBCT - Lease-To-Own, by making the following changes: 1) made the same changes described in the last paragraph of Section 3.2; 2) implemented an if-then algorithm to calculate the total annual payment from the subscribers (anchor and residential) to the developer as the sum of the panel lease, Admin & Transaction, and O&M costs until their cumulative payments equal the total installed cost of their portion of the array plus the upfront Admin & Transaction costs for Year 0. At that point, the annual subscriber payment to the developer is lowered to just the sum of the O&M and Admin & Transaction costs times 1.1 (to guarantee the 10% return as discussed in Section 3.2) for the rest of the 25-yr lifetime. This approach assumes that: 1) the developer does not require an additional lump sum payment from the subscribers at some point after the subscribers reach the threshold system payment; 2) the residential and anchor subscribers are logistically and legally able to share ownership of the array after they have reached the threshold, at no additional cost; and 3) the developer and subscribers are willing to keep the developer in the role of array/subscription manager after ownership has transferred, with no changes to annual costs when that transfer happens.

3.4 True Ownership (TO) Model

We include the True Ownership (TO) model because due to prior Maine policy restrictions, TO is the only way CSFs in Maine have occurred. Now that state policy has changed, the TO model may not be as common, but for the last six years, it has been the status quo. The TO model represents a group of subscribers that have decided together that they want to collaborate on a CSF, find an installer to do the work, share the benefits and costs proportionally to their power capacity shares, and not involve a developer or any lease payments. It is very simply modeled like a traditional distributed generation array but with all costs and benefits shared across all subscribers proportional to their share of the array's power capacity. Using the Panel Purchasing Model we developed for Maine (Section 3.2) as the basis, we: 1) set the developer discount rate equal to the subscriber discount rate (10%) because all participants are essentially developers and subscribers at the same time; 2) set the annual site lease payment to zero because the anchor host will be able to take advantage of MACRS, so not charging the site lease payment is a way to pass on some of that savings to the residential subscribers who cannot take advantage of MACRS; 3) moved the federal ITC from the developer cash flow to the host and residential subscriber cash flows with each taking the ITC proportional to their share of panels (this of course assumes that all subscribers have sufficient tax appetite to claim their portion of the ITC, which may not be the case); 4) calculate the host and residential Year 0 net costs in their respective cash flows as the sum of the cost of land/site preparation, equipment and labor, and upfront Admin & Transaction costs multiplied by their respective share of the array's rated power capacity, plus the loan (same financing terms as PP) and federal ITC cash equivalent payment they receive in Year 0; 5) calculated the host and residential Year 1-25 net benefits or costs in their respective cash flows as the sum of ongoing Admin & Transaction and O&M costs plus RECs (assumes residential subscribers are able to sell RECs either directly or through the anchor subscriber), multiplied by their share of the array's rated power capacity, plus loan payments (years 1-6 only) and MACRS cash equivalent benefits in Years 1-6 (host only); 6) removed the ITC and loan amount and payments from the subsidized subscriber cash flow and added a subscriber subsidy equal to half the cost of the upfront residential subscriber panel purchase in Year 0 (the subscriber subsidy is assumed to only go to LMI participants who would not have the tax appetite for the ITC and may not be able to qualify for a loan). Table 5 summarizes the 4 financial models we developed for our Maine-based ACTT cases. There is not currently a subscriber subsidy available in Maine, but we included both unsubsidized and subsidized subscriber cash flows (50% IL panel lease/purchase subsidy) in our Maine case study models to see the comparative effects if Maine ever did offer such a subsidy.

Table 5 - Mount Desert, Maine Financial Models

Maine Case # Name	Maine Financial Model	Basis	Host Tax-Exempt ?	SA	IP	Yr 1 Cost	Loan	ITC	MAC RS	SLP	PLP/ PPP	A&T, O&M Cost	A&T, O&M Imp.	LT Own
#27 MDL	Panel Lease (PL)	UAL #14	No	1.5 %	D	D	No	D	D	D	10% IRR	D	D	D
#28 MDLO	Lease-to-Own (LTO)	MDL #27	No	1.5 %	D	D	No	D	D	S	10% IRR	H/S	D	H/S
#29 MDP	Panel Purchase (PP)	MDL #27	No	0%	D	D	H/S	D	D	S	10% IRR	H/S	D	H/S
#30 MDG	True Ownership (TO)	MDP #29	No	0%	H/S	H/S	H/S	H/S	H	No	Install Cost	H/S	H/S	H/S

**Maine Case Name # corresponds to Table 2; Basis = spreadsheet used as basis to develop model; SA = annual subscriber retirement/acquisition rate; IP. = initial purchase (of panels); ITC = federal investment tax credit; MACRS = Modified Accelerated Cost Recovery System federal depreciation incentive; SLP = site lease price; PLP/PPP = panel lease price/panel purchase price; 10% IRR = used Excel's Goal Seek function to achieve 10% internal rate of return for developer; Install Cost = cost of equipment and installation labor; A&T = administration and transaction; O&M = operation & maintenance; Imp. = implementation; LT Own = long-term ownership; D = developer; H = host (anchor subscriber); S = subscriber*

4.0 Results and Discussion

Overall, the changes in federal tax incentives and error we fixed in the Admin & Transaction costs increased the lifetime costs and decreased the benefits in the CCCSP case studies enough to create a stark divide between subscribers and system owners (Figures 3-4), making it difficult for projects (especially larger ones) to achieve a positive unsubsidized subscriber NPV in IL, while also maintaining a 10% IRR for the system owner. In fact, 61% of IL cases yielded a negative NPV for unsubsidized subscribers. IL subscribers tended to fare better in the smaller projects due to higher REC incentives, which enable system owners to charge lower PLPs and still achieve a 10% IRR. Subscribers fared better in the Maine PL case (#27) compared to similar-sized IL cases (#15-16), with unsubsidized ME subscribers achieving NPVs 8-13 times those of IL subscribers. Although not a perfect comparison because of many factors that differ between IL and ME policies and case study sites, this large difference suggests that the higher state incentives CCCSP modeled in the IL cases are not sufficient to overcome the lower rate of net metering bill credits (energy only) offered by the state. This dilemma may be one reason IL decided to change the REC incentive compared to what CCCSP modeled. Assuming #15 and 16 would be eligible for the ILSFA, under the new IL community solar policy outlined in the LTRRPP, they could expect to receive a REC price of around \$70/MWh (Illinois Power Agency (IPA) 2020) instead of the \$53/MWh the CCCSP modeled in 2017. This REC price would enable the system owner to lower the PLP to \$1.13/mo (#15) and \$1.85/mo (#16) while still achieving a 10% IRR and yielding unsubsidized subscriber NPVs of \$1,736 and \$1,216, respectively. This observation underscores the central role of state policy in making CSFs affordable to different stakeholder groups. Also, in all case studies that included developer and host ownership models, the host-owner NPV was higher than the developer-owner (#2>#1; #3>#4; #6>#5; #9>#7 or #8; #13>#11 or #12; #19>#20; #21>#22), except for #23 and #24 where the developer-owner NPV was higher than the host-owner. For the tax-exempt host-owners, this is because the owner needs to charge a higher PLP to overcome the loss of the MACRS tax benefit (the tax-exempt host receives a state subsidy equal to the ITC, so losing the ITC is not a problem) and achieve the target 10% IRR. The higher PLP leads to more annual revenue for the host-owner, increasing the NPV, but at the expense of the residential subscriber who has to pay a higher PLP, and therefore typically has a lower NPV in the tax-exempt host-owned cases than their developer-owned counterparts.

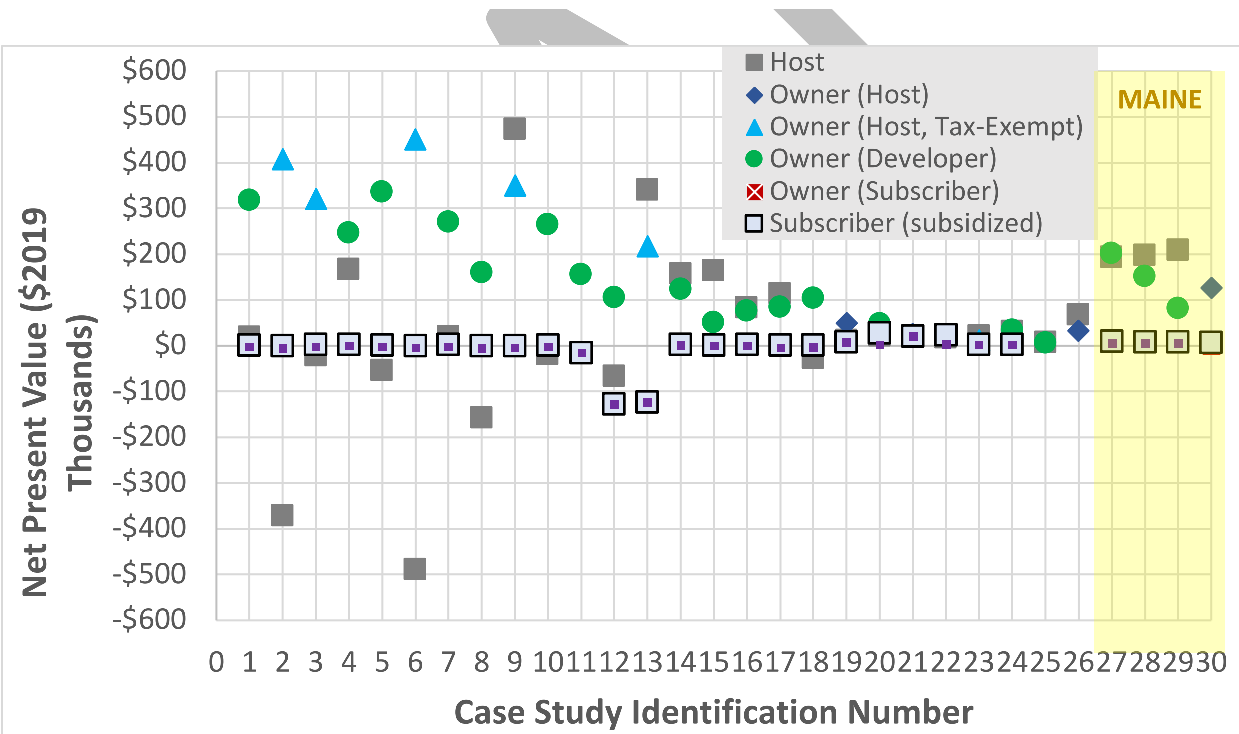

Figure 3 - Net Present Value (NPV) for all stakeholders

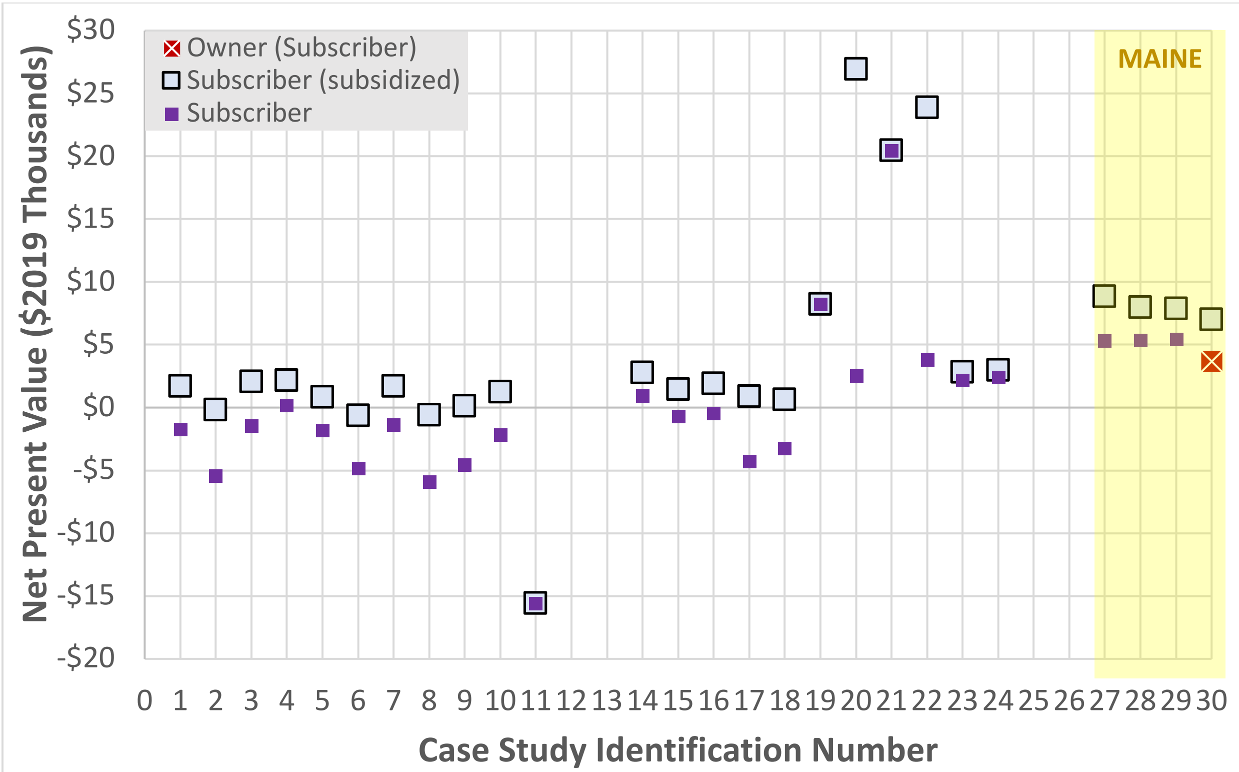

Figure 4 - Net Present Value for Subscribers Only. #12 and 13 are outliers at -$127 and -$123 thousand, respectively.

There is a clear trend across the Maine models: as degree of subscriber ownership increases (from no ownership in #27 MDL to year 1 panel purchase in #29 MDP), developer NPV decreases while host (anchor subscriber) and unsubsidized residential subscriber NPV increases (although the increase for the residential subscriber is smaller (1-2% compared to the previous model) than the anchor subscriber (2-6%)). This trend does not continue to true ownership (#30 MDG), however, because in this model the host and residential subscribers share the development costs. From an unsubsidized residential and anchor subscriber perspective, #29 is clearly the preferred Maine choice based on NPV. However, the developer can achieve an NPV 2.5 times higher with #27, while still offering substantial benefits to both subscriber types. Under these financial circumstances, developers may try to sell subscribers on a lease model to improve their own financial situation, but if subscribers are aware of the additional value they could achieve with a purchase model, they may be more inclined to pursue a purchase arrangement. There is no low-income subscriber subsidy in Maine like that modeled in the CCCSP cases. However, since the CSBCT easily allows it, we left the IL subscriber subsidy (0.5 times the PLP or PPP, ending at the same time as the panel lease price in the MDLO model) in for the Maine cases to see what would happen if Maine adopted a low-income subscriber subsidy similar to what CCCSP was envisioning for IL in 2017. Unlike the unsubsidized residential subscribers, the subsidized subscribers have a higher NPV with the Lease model (#27) than the other Maine cases because the subsidy only continues as long as the subscriber is paying the PLP or PPP; #28 and 29 incur increasing subscriber annual costs as more ownership is obtained; and there is no loan for the subsidized subscriber in the MDP model. Given all of these factors, based on NPV alone, and balancing the stated goal of low-income participation (which would be challenging with the large upfront cost of a panel purchase model), we recommend ACTT consider the MDLO model because it provides a substantial developer NPV, while providing ownership options and strong NPVs for all subscribers.

Similar to all economic analyses, these results are sensitive to the discount rate used. For example, if we cut the developer and subscriber discount rates in half (4% and 5%, respectively) in the MDLO model, NPV increases by 254% for the developer, 63% for the host, 74% for the unsubsidized and 135% for the subsidized residential subscriber. If we double the discount rates compared to the original MDLO model (16% and 20%), NPV decreases by 306%, 56%, 61%, and 55%, respectively. This sensitivity to discount rate underscores the effect time value of money has on comparative results and the importance of being able to accurately model the discount rate for the specific target participants. In reality, a low-income participant may have an infinitely high discount rate because they may not be capable of trading money now for money in the future. On the other hand, someone with very strong values about intergenerational resource responsibility and enough wealth to be able to pay upfront costs may have a discount rate closer to zero or even negative. We used the default discount rates selected by the CCCSP for their case study analysis, but they did not include a rationale for the discount rate selection. As ACTT and others go forward in CSF development, it is important to model a range of discount rates. We recommend the CSBCT be adapted to accommodate different discount rates for host, subsidized and unsubsidized residential subscribers (right now, there is just one subscriber discount rate for all three) and to allow the user to easily vary discount rate over time if desired. The true ownership and panel purchase models require a large upfront cost, with benefits accruing over time; whereas, the lease and lease-to-own models allow the subscriber to achieve benefits (including ownership for LTO) but spread out their initial cost over several years or not pay it at all (lease). For a subscriber that has a very large preference for money now rather than later (high discount rate), lease or lease-to-own will be increasingly appealing, while someone who has equal preference for money now and in the future (discount rate = 0) might prefer the true ownership or panel purchase model.

NPV does not tell the whole story, either. Looking at the cash flow itself can provide a better understanding of how a participant may or may not benefit from the financial arrangement. Figure 5 presents the unsubsidized subscriber cash flows (net benefits or costs) for all four Maine models, without discounting and discounted to present value (Equation 1 without the summation). It is clear from this figure why the lease model is attractive from a subscriber perspective: the net cash flow is positive and steady each year, even with discounting. However, the subscriber has a lot more to gain financially with the MDG and MDP ownership models, but also a lot more to lose in year 0 or 1, respectively. Figure 5 reinforces our recommendation above that ACTT consider the MDLO model because it provides a path to ownership while also maintaining a positive cash flow each year (even with discounting) and yields greater returns at the middle-end of the cash flow than MDL. The only drawback to MDLO for the subscriber is the cash flow in the early years is not quite as high as MDL. Figures D1-D3 in Appendix D provide additional cash flow visualization for IL versus ME residential and anchor subscribers.

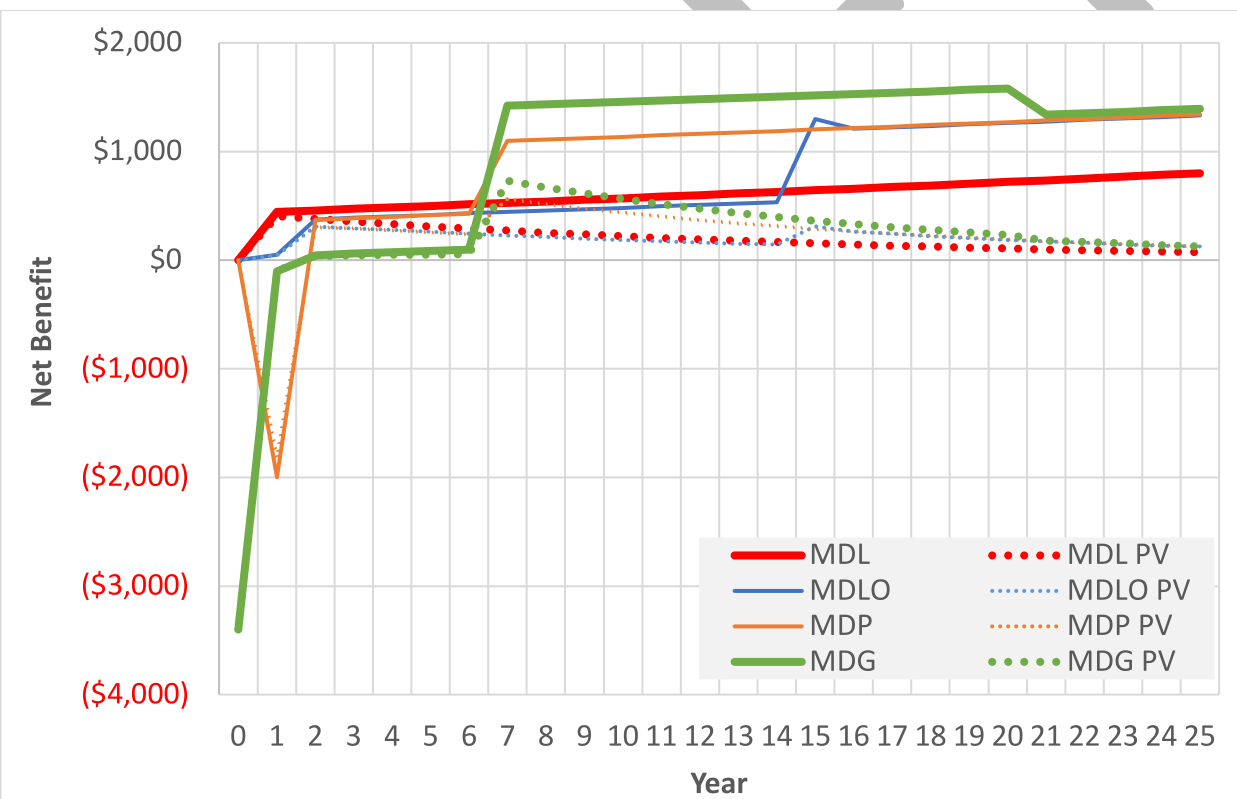

Figure 5 - Annual Unsubsidized Subscriber Cash Flow (Net Benefits or Costs) for the Maine financial models *(without discounting and discounted to present value (PV))*

The host and subscriber (including subsidized) return on investment for the Maine panel purchasing with developer case (#29 MDP) outperforms nearly all other results for all other cases (except IL #24). However, the developer ROI for #29 is the lowest out of the Maine set. In general, the ROI results provide further support for selecting a lease-to-own option (#28) for Maine because it still has a relatively high ROI for all participants and the gap between developer and subscriber is narrower than #29. In general, ROI results track with NPV results in that most participants that have a positive NPV in Figures 3-4 also have a positive ROI. However, ROI does not as clearly show the magnitude of the benefit as NPV does. For example, Figure 6 shows a very large subscriber ROI for #23-24 (up to nearly 400% for the #24 host), but Figures 3-4 reveal those ROI values to be on very small investments yielding small NPVs compared to the other projects. Therefore, ROI should be considered in tandem with NPV and not on its own when selecting among multiple projects.

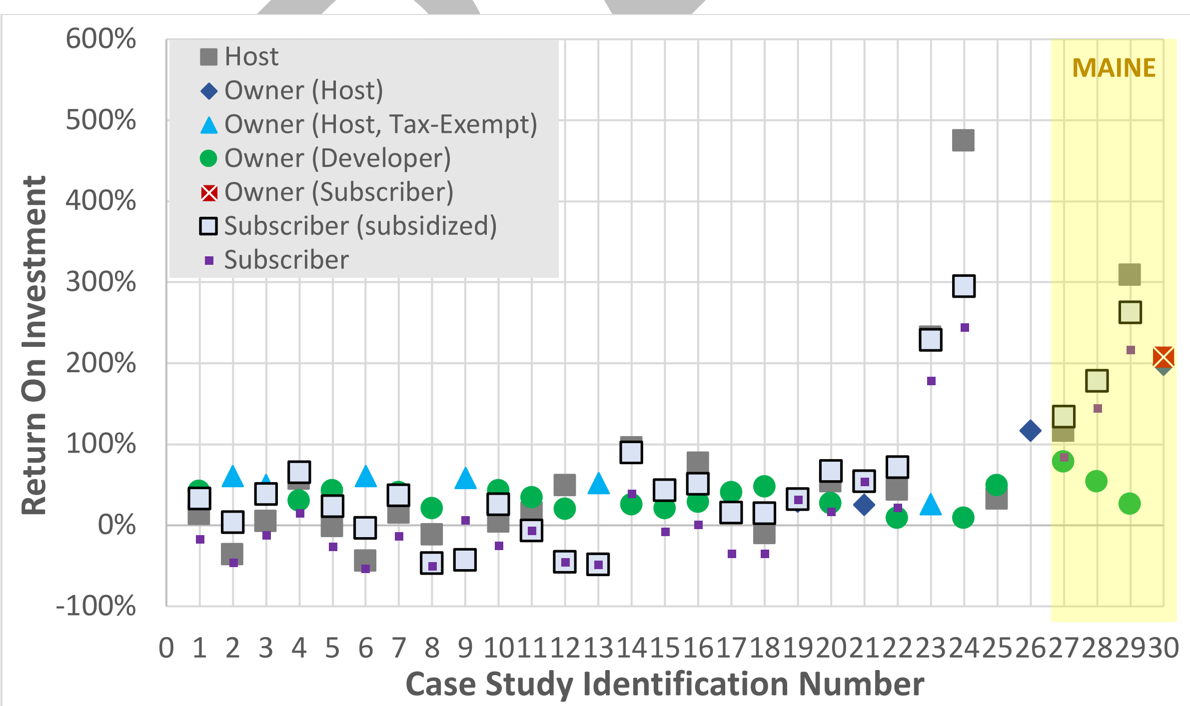

Figure 6 - Return on Investment (ROI)

Although NPV and ROI may be important financial metrics for businesses and large organizations, most individual residential consumers and many small non-profit organizations want to know their simple payback period before proceeding with an investment, and the lower the better (Figure 7). By this metric, unsubsidized subscribers to smaller IL panel leasing cases fared better than larger cases because smaller projects achieved higher RECs, allowing developers to charge lower lease prices. The subscriber subsidy was sufficient to overcome the higher panel lease prices of the larger projects. It is unlikely that any project with a subscriber payback period greater than zero for a lease model will be successful in attracting and retaining subscribers in the long run since the primary benefit of lease over other models is immediate substantial savings. It is possible the new IL state policies outlined in the LTRRPP have improved the financial situation for the cases with high subscriber PBPs. For example, the higher ILSFA REC prices discussed above in the NPV analysis for #15 and #16 yielded PBPs of zero for all subscriber types for those projects, compared to 20 years in Figure 7 with the original CCCSP REC prices. With PBPs of zero for all subscriber types, the lease-to-own Maine model (#28) is again favorable for this metric, especially since it also includes an added benefit of years to ownership that are about midway through the cash flow. Although #29 and 30 provide ownership in one year, the large upfront investment caused the payback period on the investment not to be experienced until years 3-7 (depending on the model and subscriber type).

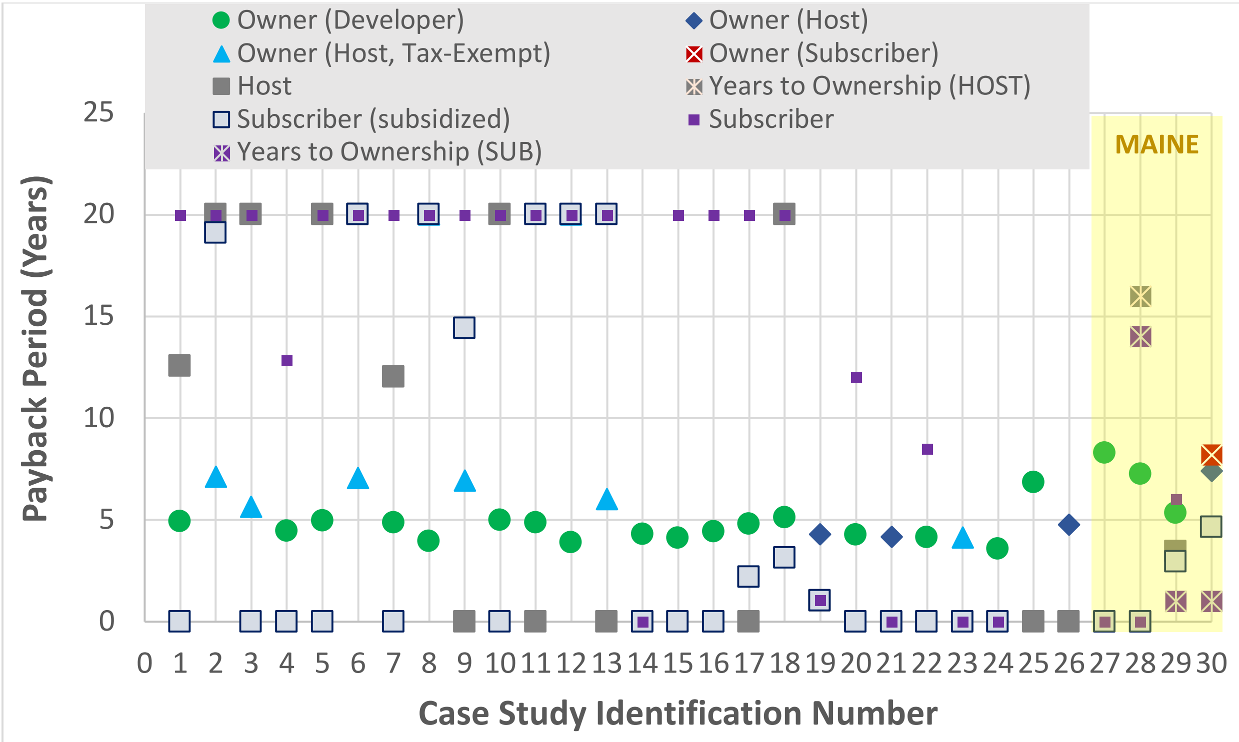

Figure 7 - Simple Payback Period

One key limitation to these results is that the CSBCT assumes that all residential subscribers have the same number of panels. In reality, in Maine at least, the subscriber's share of panels will be determined by the electric load they are trying to offset, and subscribers may end up leasing or purchasing different numbers of panels. Also, the CSBCT only allows for a constant subscriber acquisition and retirement rate, whereas in reality that rate could vary based on many exogenous factors. In addition, while the purpose of this analysis was to compare our Maine cases to existing quantitative models, with so many different inputs to the CSBCT and with all of the differences between case studies within the same state and across states, it is difficult to isolate the effect of state and federal incentives on the results. Therefore, we created a set of incentive scenarios for the Maine lease model (#27 MDL) and compare them with equivalent scenarios for the same solar energy system (same size, system losses, anchor subscription percentage, etc. as #27 MDL) with IL-specific inputs: monthly energy generation profile for Chicago, IL from PVWatts with #27 MDL system losses, inverter efficiency and system type (ground tracking); IL-specific labor rate; IL state incentives where applicable (Figure 8). Even without incentives, a developer can achieve a substantial positive NPV in both states. However, the PLP needed to achieve a 10% IRR pushes the host and subscriber NPVs for IL very far negative, while allowing a positive host NPV in ME and a negative subscriber NPV close to zero. The federal incentives alone allow Maine to achieve a positive NPV for all three stakeholders, but state incentives are crucial to IL's subscriber viability. This is largely due to the fact that electricity bill credits in Maine include energy and delivery charges and a higher rate base than Illinois, while Illinois bill credits only include energy charges (and also somewhat due to the lower labor rate in Maine), since both locations have similar annual electricity generation (~1,000 MWh/yr). The higher ABP REC rate from the recent LTRRPP helps IL achieve higher subscriber and host NPVs than the older state incentives assumed in the CCCSP case studies, but Maine still fares better with the federal and state scenario even with a lower anticipated REC price. Figure 8 also more starkly demonstrates the tradeoff in subscriber versus developer NPV observed in Figures 3-4: holding developer IRR at 10% results in lower developer NPV when incentives increase because the incentives are passed on to the subscribers as lower PLPs. In reality, developers may choose to increase IRR and NPV and not lower PLPs unless policy requires a minimum subscriber annual savings.

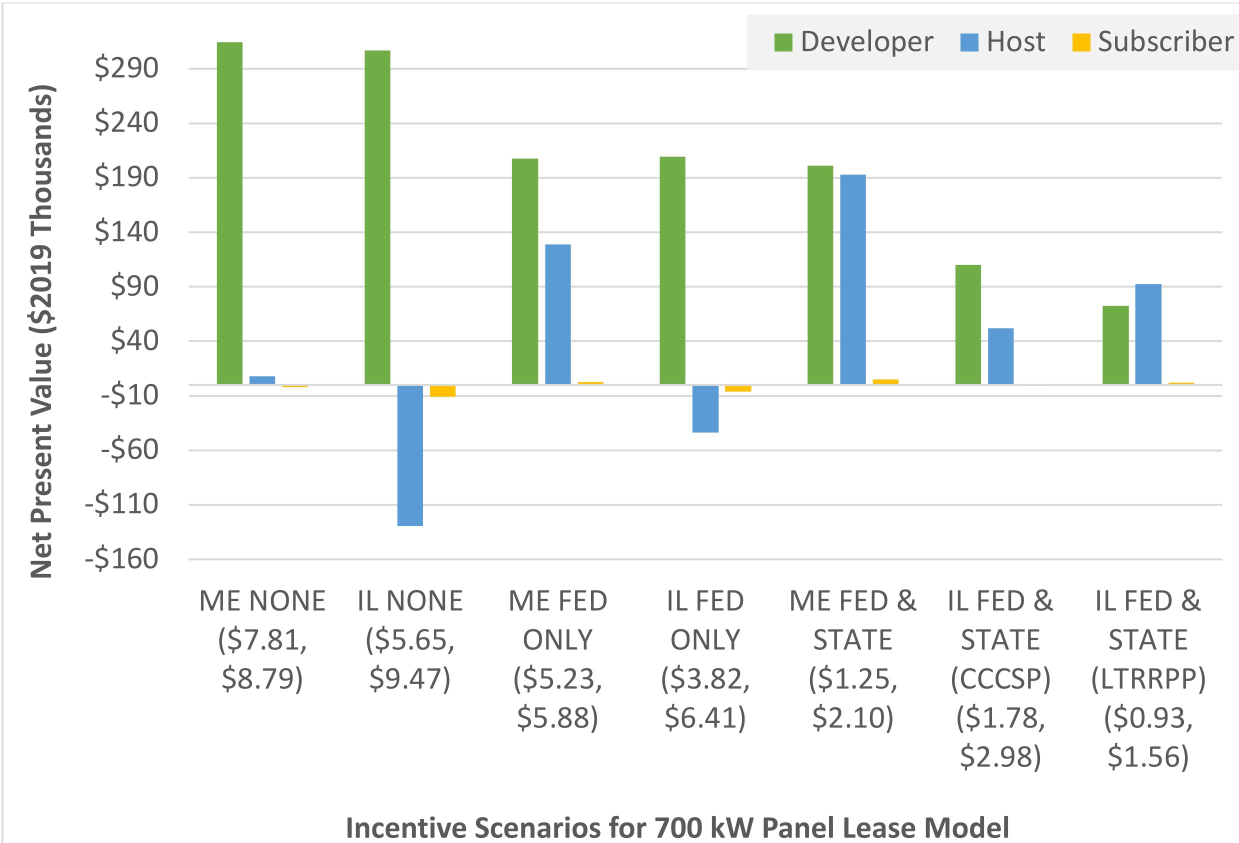

Figure 8 - Effect of Financial Incentives on Panel Lease Model in Maine and Illinois. *NONE = No incentives; FED ONLY = 26% federal ITC and 5-yr MACRS at 21% tax base; FED & STATE = #27 MDL for Maine; CCCSP uses the $45/MWh REC price; LTRRPP uses the $70/MWh REC; no subscriber subsidies are included in any scenarios; costs in parentheses after scenario names = monthly commercial and residential panel lease prices.*

5.0 Conclusion

This is the first study to quantitatively compare multiple financial metrics for different community solar farm financial models across varying scale (system size), stakeholder involvement (role of owner, host, subscriber), geographies, and policies. Our analysis of the 26 Community Solar Business Case Tool spreadsheets prepared by the Cook County Community Solar Project for 15 case study locations in the Chicago, IL area in 2017, reveals that updated federal incentives (including a lower investment tax credit (26% instead of 30%) and lower tax base for the Modified Accelerated Cost Recovery System for depreciation (21% instead of 35%)) applied in tandem with two key error fixes (Admin & Transaction Costs and Discount Rate) make many of the 26 financial models inaccessible to residential subscribers at a 10% system owner IRR unless a low-income subsidy is in place. IL subscribers fared much better in the smaller projects (<500) than the larger ones. Adjusting state-level RECs for all 26 IL financial models to be consistent with the recently released IL Power Agency LTRRPP was beyond the scope of this analysis. However, a close look at one model reveals that in some cases, the new state REC prices in the LTRRPP may be sufficient to overcome the financial challenges created by recent federal incentive changes. Though, a more generous net metering bill credit rate and lower labor rate in Maine provide more net benefits to all stakeholders (developer, host, and subscriber) than the higher Illinois REC price for the panel leasing model.

Our Maine financial model comparison revealed the lease-to-own model to have the strongest set of financial benefits to all stakeholders while also providing a path to ownership. We recommend ACTT and other organizations like ACTT consider the lease-to-own model for their purposes. However, for entities attempting to have meaningful low-income participation in a CSF (like ACTT), the lease-to-own model presents unique challenges associated with finding a developer that is willing to forego the additional returns they could achieve with a lease model and create a legal ownership structure later in the project lifetime that low-income subscribers can access even though they may not have traditional strong financial metrics (e.g., suitable credit scores). Future research should quantitively compare multiple lease-to-own models with varying loan, tax equity (e.g., Partnership Flip, Inverted Lease, and Sale Leaseback (Cockerham 2018)), ownership transfer timelines, and other parameters, as well as varying mixes of subscribers who want to achieve ownership versus those who want to stay on lease (e.g., an opt-in lease-to-own arrangement). Our work just scratches the surface of all of the different financial models that could be possible with lease-to-own. The Maine analysis also quantitatively supports assertions made in CCCSP documentation that the panel purchase model "provides a better return over the life of the system…but requires an upfront investment that will be too burdensome for many potential subscribers" (Burciaga 2017,p.38). Quantitative support for this argument is important because Cook County does not actually provide any data or spreadsheets that model panel purchasing in their case study materials.

Overall, these comparative, quantitative case study results are useful for illustrating the points discussed above and advancing knowledge of community solar financials under different circumstances. In addition, the detailed site-specific CSBCT and associated CCCSP case study spreadsheets (along with our new spreadsheets) are useful for modeling and understanding site-specific factors in a transparent way. However, the spreadsheet style of the CSBCT limits the type of large-scale optimization and uncertainty analysis needed for understanding the probability of different financial returns in different geographic locations under varying ownership structures and incentive policies. We recommend the CSBCT be converted to a programming language (e.g., Matlab, R, etc.) and this analysis be expanded to include additional geographic locations with associated state/local policies and prices across the US and internationally, more flexible subscriber parameters (e.g., separate discount and loan rates/timelines for anchor, unsubsidized and subsidized residential, subscriber acquisition/retirement rates and discount rates that vary over time, varying subscriber power capacity shares), and probability distribution data developed and included for uncertain inputs (e.g., discount rate, loan terms, capacity factor, installation and electricity pricing, etc.) to examine the relative sensitivity of these uncertain inputs on financial outputs. In addition, it would be helpful to incorporate the ability, in a transparent way, to identify preferences for specific financial metrics over others, as well as preferences for non-financial metrics (e.g. emissions savings, economic impact/jobs (discussed in Cook County documentation but not included in the CSBCT), low-income participation, community resiliency, energy literacy, etc.) through social benefit-cost analysis and/or multi-criteria decision analysis.

ACKNOWLEDGEMENTS

This work was supported by the United States Department of Agriculture National Institute of Food and Agriculture Hatch projects 0230040 and 021813. In addition, we would like to thank Fortunat Mueller from ReVision Energy and Gary Friedmann from A Climate To Thrive for providing information and data inputs for the Maine business cases examined in this article, and Emily McGavisk and Vito Greco, the creators of the incredibly useful and timely Community Solar Business Case Tool, for so carefully and thoroughly documenting the inputs and results of their analyses and making the CSBCT and supporting documentation publicly available and easily accessible.

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APPENDIX A

Table A1 – Financing mechanisms with potential for community solar

Name of Financing Mechanism	Description	Ideal for LMI?	Used in Maine?	Other states where used	Citations relevant to this row
Bond Program	A program where entities or organizations looking to implement clean or renewable energy can request bonds from their state government to help fund the project	Yes	No	IL, ID, UT, NM, HI	("DSIRE" n.d.)
Bulk Purchasing*	allows multiple people to purchase systems together at a lower cost (not typically directed to LMI)	No	Yes	Many (MA is leader)	(Cook and Bird 2018; NRCM 2015)
Capital Refinancing*	"a building owner negotiates a new mortgage rate and term to generate additional capital for building improvements including PV", not used widespread for PV	N/A	Yes	Many	(Cook and Bird 2018) p. 3
Crowdfunding	financing approach where capital is from public donors instead of from accredited investors, viability varies case-by-case	No	No	NY, CA, FL, MA, ID, WV	(Cook and Bird 2018) p. 3
Direct Cash Incentives	Payments/reimbursements (grants/rebates) for the deployment of PV. Rebates in some states will cover the full system cost for LMI residents	Yes	No (yes before LePage)	CA, CO, D.C., IL, MA, NY, WA	(Cook and Bird 2018) p. 4, (Paulos 2017) p. 25-27
Grant Program	A program where organizations can apply for a grant to help them fund a renewable energy project. There are several grant programs available from the Federal government but only for special groups.	Yes	No	WA, OR, CA, AK, CO, MN, WI, MI, IL, IN, NY, PA, MD, RI, MA, NH	("DSIRE" n.d.)
Green Banks	A specialized financial entity that works with the private sector to fund sustainable infrastructure projects with environmental benefits. Typically helps to finance commercially viable and proved clean energy technologies which may face barriers attracting capital.	Possibly	Yes	CT, NY, CA, RI, MD, HI	(Green Bank Network 2020)
Green Power Purchasing	Legislation that mandates that a certain percentage of power for all government buildings must come from a renewable energy source. In Maine all government buildings must use 100% renewably produced energy with preference being given to community-based renewable energy generators.	Possibly	Yes	AZ, CO, TX, WI, IL, MI, PA, MD, SC, MA, CT	("DSIRE" n.d.)
LIHEAP/WAP*	Low income home energy assistance program/weatherization assistance program; DOE programs that allow states to use the program money to install cost-effective PV	Yes	Yes (but not for solar - used for weatherization)	Avalible in all states	(Cook and Bird 2018) p. 4

Loan Loss Reserve	Makes it easier for low-credit score residents to get loans for solar because the loaner is offered protection for the provision of the loan; most likely used in conjuction with one of other loan options listed here	Yes	Probably not (technically maybe possible with PACE?)	NY	(NREL 2020)
Loans*	granted by public or private financial instutions, often under-subsidized terms, used to deploy PV; potentially may be combined with Loan Loss Reserve for people with low credit scores	Possibly	Maybe (ReVision?)	MA	(Cook and Bird 2018) p. 4, (J. S. Heeter et al. 2018)
Net Metering	Compensation structure that allows for customers to be credited for the excess generation of their PV system, net metering programs do not typically address up-front cost barriers, additional incentives would need to be offered to aid LMI residents	No	Yes	AK, AR, AS, AZ, CA, CO, CT, D.C., DE, FL, GA, GU, HI, IA, ID, IL, IN, KS, KY, LA, MA, MD, ME, MI, MN, MO, MP, MS, MT, NC, ND, NE, NH, NJ, NM, NV, NY, OH, OK, OR, PA, PR, PW, RI, SC, TX, UT, VA, VI, VT, WA, WI, WY	(Cook and Bird 2018) p. 4, ("DSIRE" n.d.)
On Bill Financing*	funding structure where a third party pays the upfront costs of a PV system and the residents pay for the investment through monthly electric bills	Yes	No	NY, NC, CO	(Cook and Bird 2018) p. 5, (Szaro 2017) p. 11, (GRID Alternatives and Vote Solar 2020b)
PACE	Property Assesed Clean Energy; allows customers to pay for PV installation through property tax bills, payments take priority over mortgages to reassure private lenders that associated loans will be repaid; potentially may be combined with Loan Loss Reserve for people with low credit scores	Possibly	Yes	CA, FL, MI	(Cook and Bird 2018) p. 5, ("DSIRE" n.d.)
Pay-as-you save (PAYS)*	The Utility invests in the energy upgrade instead of the homeowner. The utility is paid back through the customer's tariff, there is no loan or lein involved and the repayment obligation stays with the property, not the homeowner.	Yes	No (utilities can't own generation)	CO? (they have a lot of coops); the utility dive article mentions a coop in NC	(Paulos 2017) p.44
Production Incentives	generation-based incentives for the output of PV systems, can be fixed or varied on market prices	No	No	AK, AL. CA, CO, FL, GA, KY, MN, MS, NC, NM, NV, NY, OH, OR, RI, SC, TN, TX, VA, VI, VT, WA	(Cook and Bird 2018) p. 5, ("DSIRE" n.d.)

Property Tax Incentive	State law that allows a taxable property to be tax exempt for a certain period of times (MA is 20 years) if the property uses an on site renewable energy source as a primary or auxiliary power system on the property.	No	No	OR, CA, AK, HI, ID, NV, AZ, MT, ND, SD, NE, KS, CO, NM, TX, MN, IA, WI, IL, MI, IN, OH, TN, LA, MO, FL, NC, VA, MD, DE, NY, VT, NH, MA, CT, RI	(“DSIRE” n.d.)
Public Benefits Fund	Money set aside from customer utility bills or through contributions from utilities. The fund supports grants for renewable energy demonstration projects to Maine-based nonprofits, consumer owned electric transmission and distribution utilities, community-based nonprofit organizations and more.	Possibly	Yes	OR, CA, MT, MN, WI, IL, OH, PA, VA, NJ, DE, NY, CT, RI, VT	(“DSIRE” n.d.)
Sales Tax Incentive	State law that exempts equipment relating directly to any solar, wind powered, or heat pump system which is being used as a primary or auxiliary power system for heating or supplying energy to an individual's residence from state sales tax.	No	No	WA, CA, NV, UT, AZ, NM, CO, ND, SD, NE, MN, IA, WI, IN, KY, TN, MI, FL, NY, VT, MA, CT, RI, NJ, MD	(“DSIRE” n.d.)
Solar Renewable Energy Credit Program	A solar incentive that allows homeowners to sell certificates for energy to their utility. The homeowner earns one solar renewable energy credit (SREC) for every 1000kWhs produced by their solar panel system.	No	No (although ME participates in RECs market)	IL, OH, PA, MD, DE, CT, MA	(“DSIRE” n.d.)
Third Party Leasing/ESA	Third Party leasing/energy service agreements (ESA) allow LMI customers or multifamily housing providers to contract with a third-party contractor to fund/construct/operate a PV system. Benefits of the PV system are then distributed amongst the customer and contractor. Third party leasing is only legal in some states, LMI residents are often not targeted due to low credit scores.	No	Yes (very limited, ReVision)	CA, OR, NV, UT, AZ, CO, NM, TX, OK, AR, IA, IL, MI, GA, VA, OH, PA, D.C., MA, MD, NY, VT, NH, CT, NJ, RI, PR	(Cook and Bird 2018) p. 5, (“DSIRE” n.d.)
Third Party Ownership (Solar Hosting)	a third-party pays a homeowner to install/operate rooftop PV, third party remains owner of the array and its generation	No (unless savings passed to renters through some established mechanism)	Yes (very limited, ReVision)	CA, OR, NV, UT, AZ, CO, NM, TX, OK, AR, IA, IL, MI, GA, VA, OH, PA, D.C., MA, MD, NY, VT, NH, CT, NJ, RI, PR	(Cook and Bird 2018) p. 5, (“DSIRE” n.d.)
Value of Solar Tariff	Customers are billed for all electricity usage under their existing applicable tariff and are credited for the solar electricity they produce under the approved value of solar tariff (VOST).	No	No	MN, TX	(“DSIRE” n.d.)

APPENDIX B

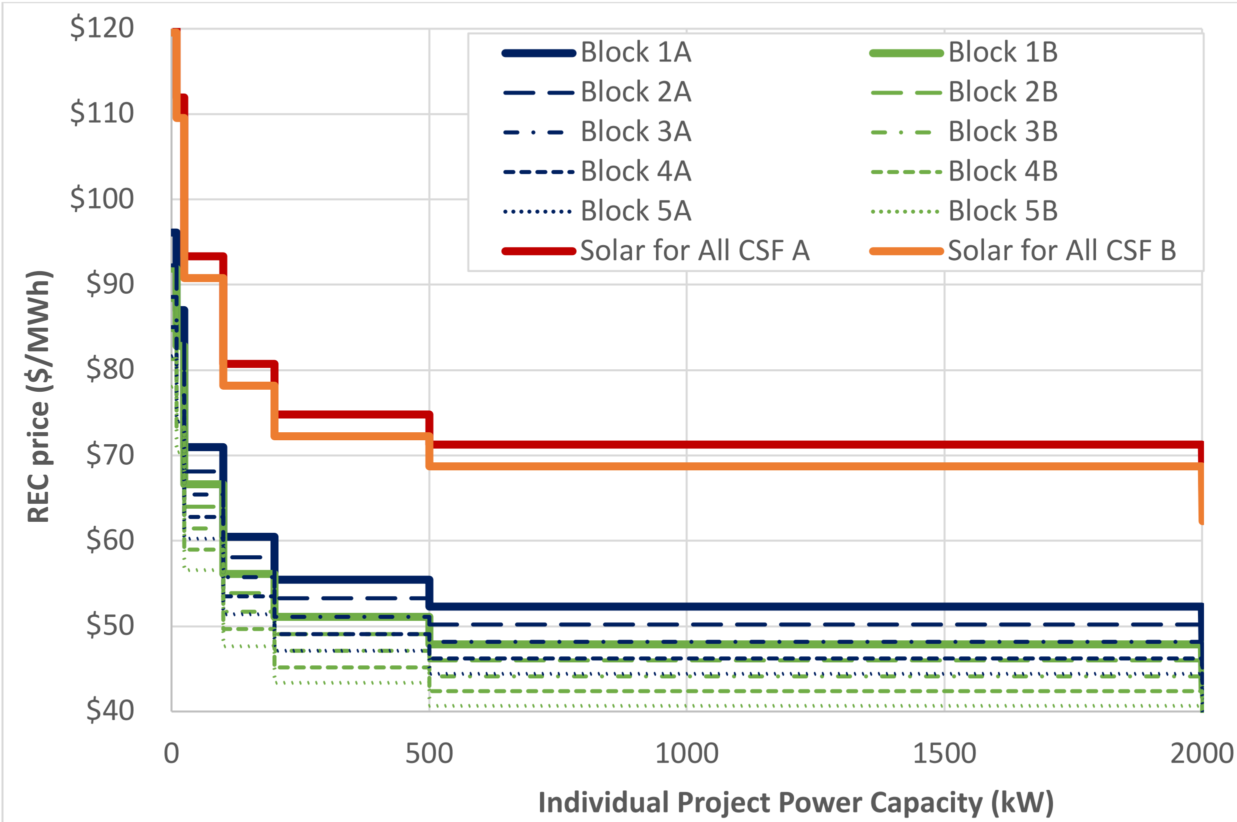

Figure B9 - Illinois Adjustable Block Program and Solar for All Community Solar Incentives *(A and B refer to different utility territories as defined in (Illinois Power Agency (IPA) 2020)).* All active blocks for the ABP CSF program are currently full, the ILSFA CSF program applications have reached funding capacity, and both programs currently have waiting lists.

APPENDIX C

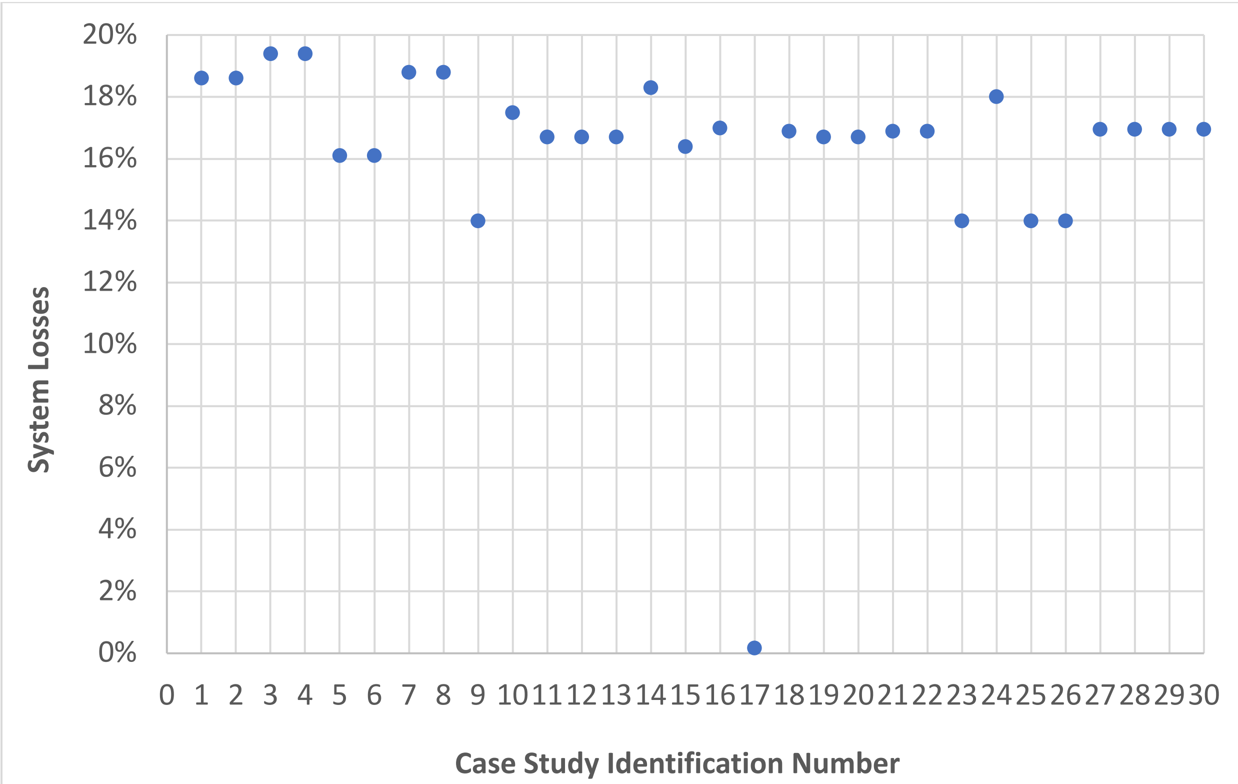

Figure C1 - System Losses (Model Input)

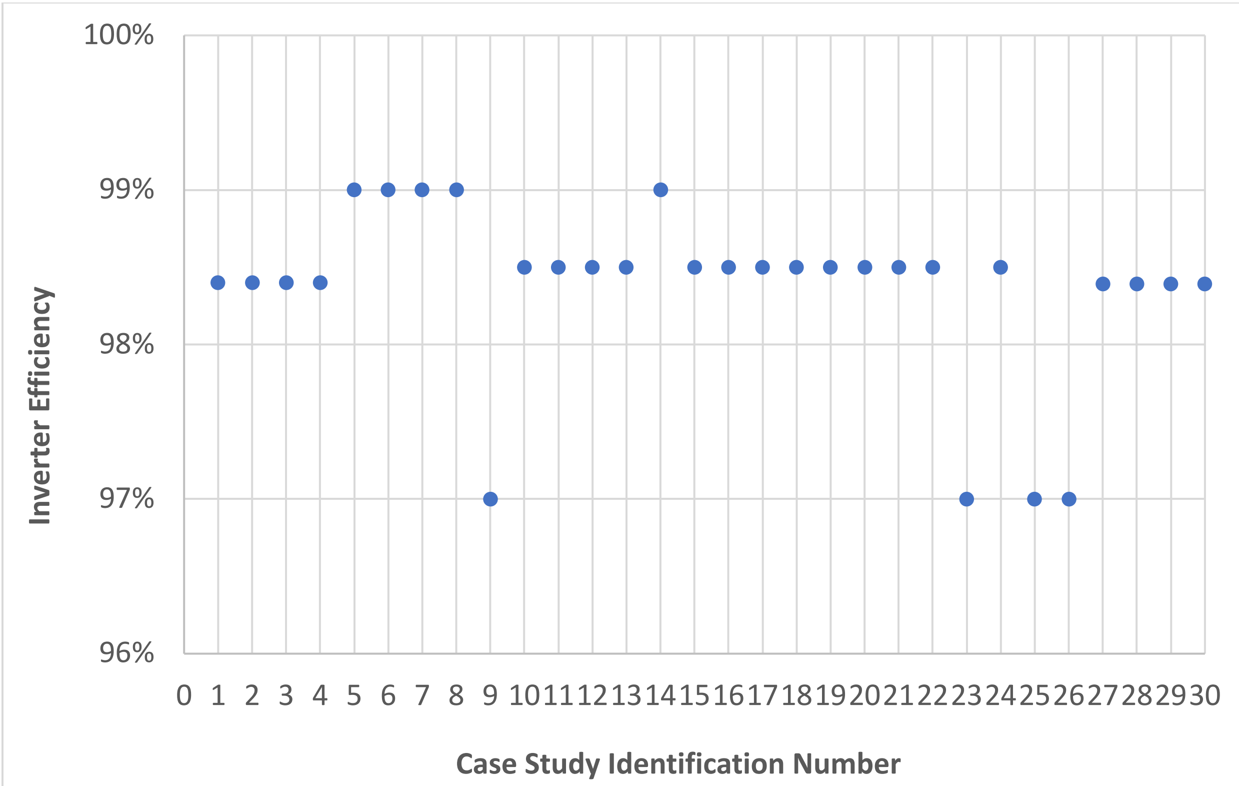

Figure C2 - Inverter Efficiency (Model Input)

APPENDIX D

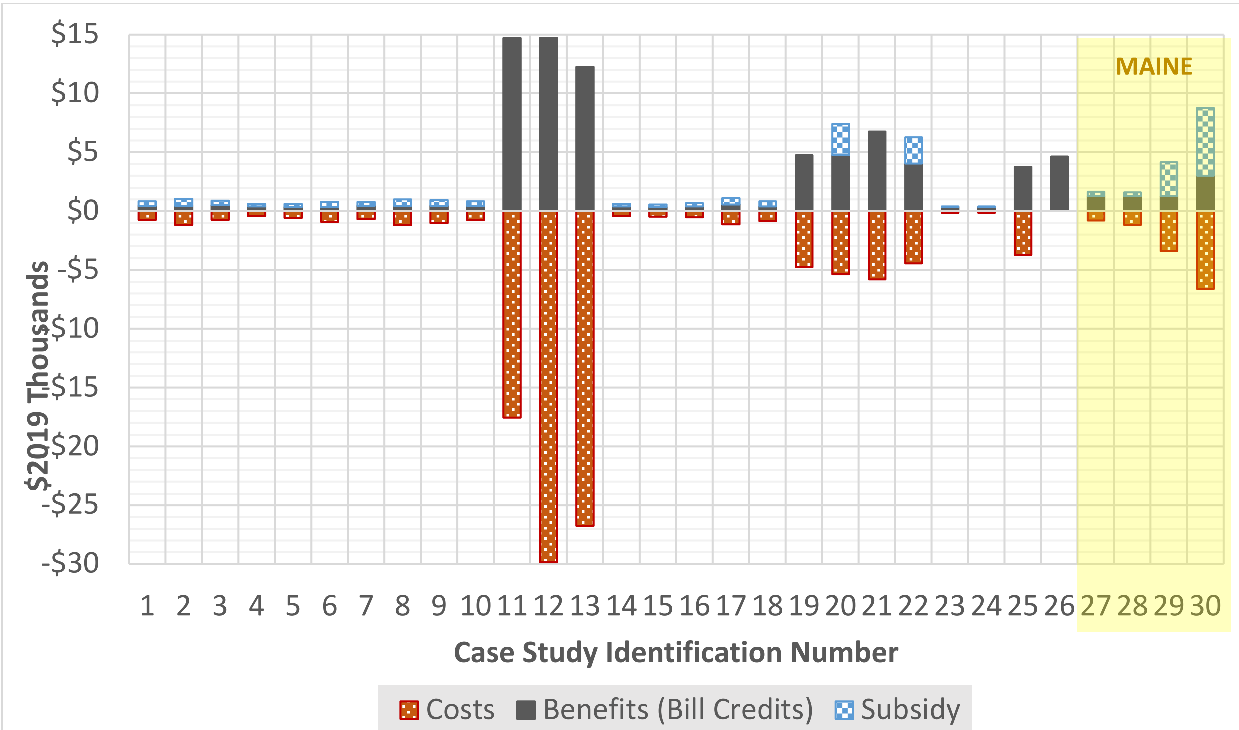

Figure D1 - Year 1 (or first-year) Subscriber Cash Flows *(for #25-26, subscriber = host because there is only 1 subscriber in those models, which are not actually CSFs; costs include loan amounts for #29 and 30; bill credits are not actually bill credits for #30 but the ITC and #30 cash flow is for Year 0, not Year 1)*

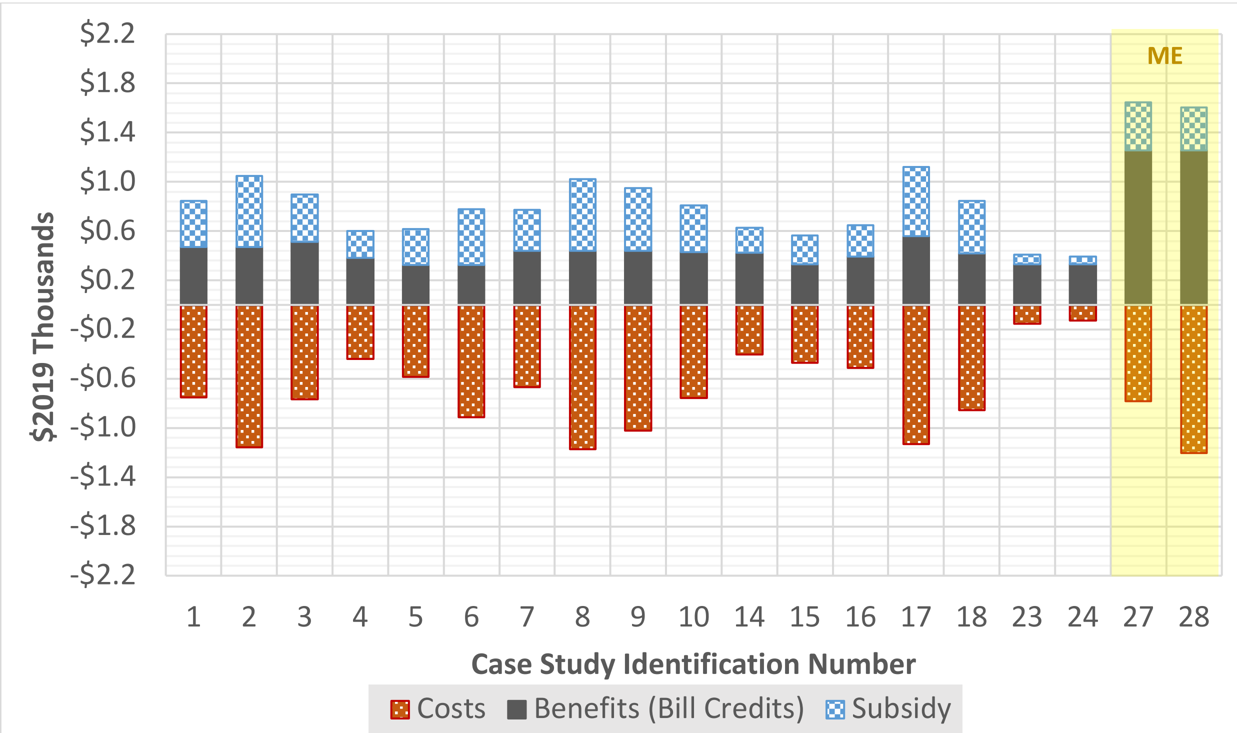

Figure D2 - Year 1 (or first-year) Subscriber Cash Flows (Zoom In) *(for #25-26, subscriber = host because there is only 1 subscriber in those models, which are not actually CSFs; costs include loan amounts for #29 and 30; bill credits are not actually bill credits for #30 but the ITC and #30 cash flow is for Year 0, not Year 1)*

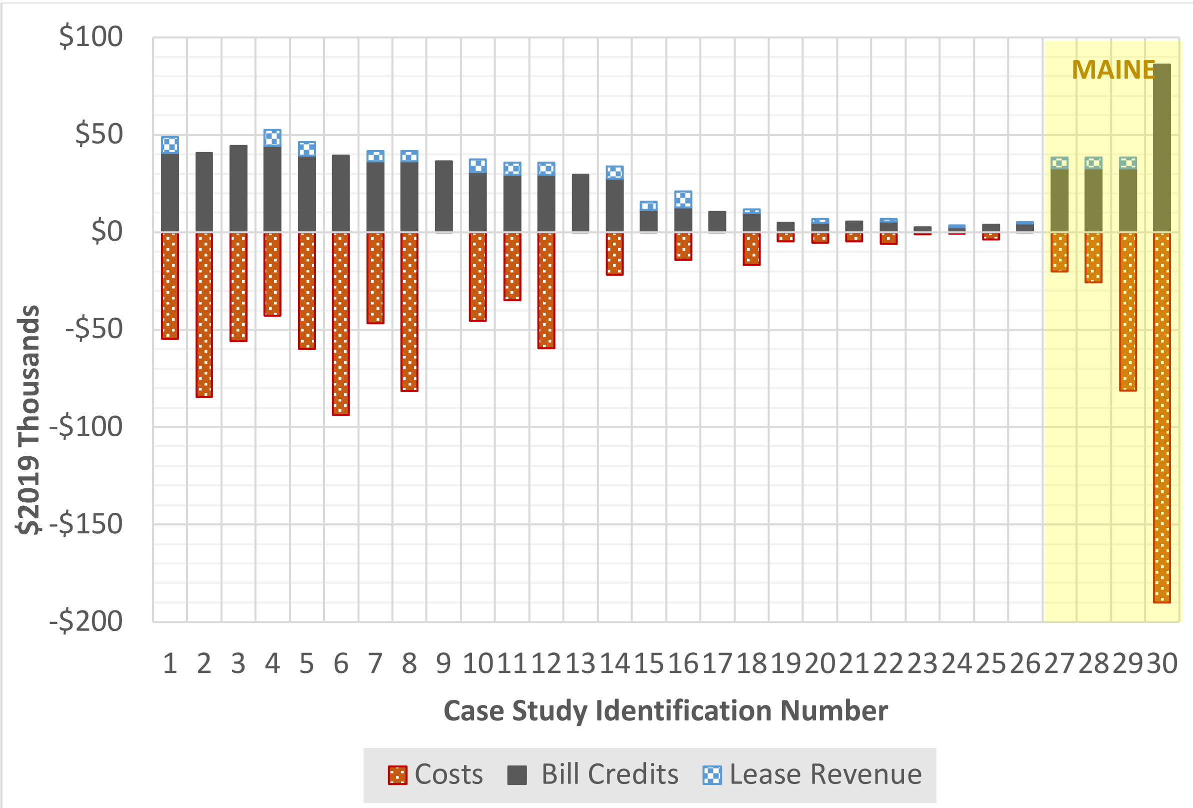

Figure D3 - Year 1 (or first-year) Host Cash Flows *(for #25-26, subscriber = host because there is only 1 subscriber in those models, which are not actually CSFs; the lease revenue for #26 is actually demand charge reductions; costs include loan amounts for #29 and 30; bill credits are not actually bill credits for #30 but the ITC and #30 cash flow is for Year 0, not Year 1)*