Distributed Generation Cost Analysis

INTRODUCTION

DEEP is committed to promoting the deployment of clean energy resources cost-effectively. Distributed generation provides many benefits to the electric grid, including but not limited to reducing system line losses, potentially delaying the need for transmission and distribution infrastructure, reducing electric bills for participating customers, increasing resiliency and energy security, contributing to economic development, and potentially encouraging positive land-use. However, current compensation and incentive structures for distributed generation that are tied to the retail electricity rate (e.g. net energy billing) present uncertainty for developers and customers, and an overall growing cost. DEEP evaluated six scenarios on how to cap the costs of these programs: These scenarios included:

1. A Business as Usual approach, in which the RSIP and LREC/ZREC programs are expanded through 2030 and net energy billing continues indefinitely.
2. A MW cap resulting in 2.5 percent of the load served by distributed generation by 2030 (i.e., 0.25 percent per year, as suggested in the draft CES in July 2017).
3. A MW cap resulting in 5 percent of the load served by distributed generation by 2030 (i.e., 0.5 percent per year).
4. A spending cap of $25 million per year.
5. A spending cap of $30 million per year.
6. A spending cap of $35 million per year

This document details the assumptions and calculations used to estimate the direct costs and benefits of these resources to Connecticut's electric ratepayers. .It does not attempt to quantify the indirect or non-energy benefits of any grid scale or distributed energy resources, and does analyze the value of distributed generation

Net Metering

Net metering began in Connecticut in the 1980's as a program for small combined heat and power systems fueled by natural gas. In 2000, net energy billing was modified to allow Class I resources to be eligible for net metering. Since then, net metering has been a key incentive in promoting the installation and deployment of Class I distributed generation in Connecticut. In accordance with section 16-243h of the General Statutes, net metering allows customers to offset all volumetric charges from their electricity bill. EDCs are required to "credit" customers for electricity generated by a customer from a Class I renewable energy source facility that has a nameplate capacity of 2 megawatts or less. These credits offset kilowatt hours supplied by the EDC. Such credits are allowed to be rolled over into the following month if production is in excess of consumption. This allows customers to net more generation at the retail rate than under monthly netting. Any excess credits at the end of the year are compensated at the avoided cost of wholesale power.[1] There is currently no cap on the amount of Class I net metering in Connecticut.

The level of compensation a participating customer receives under net metering is a direct result of retail electricity rates. DEEP calculated the net energy billing rates by only accounting for the volumetric charges a customer is allowed to offset from their electric bill. For residential customers this would account for nearly all of the electric charges on a customer's bill, with the exception of customer service charge.

TABLE 1: Historical Residential Net Energy Billing Rates (cents/kwh, nominal$)[2]

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Standard Service Generation	11.87	12.26	11.15	9.71	8.37	7.61	9.46	10.59	8.34	8.04
Volumetric Energy Charges	5.10	6.36	6.57	6.76	6.94	7.49	7.57	7.93	9.18	9.99
Total Net Energy Billing Rate	16.97	18.62	17.72	16.46	15.31	15.10	17.03	18.51	17.52	18.03

Commercial and industrial (C/I) customers are also allowed to offset all volumetric charges, with the exception of customer charges and demand based charges. Demand-based charges generally make up a large portion of the bill. Therefore, C/I electric bills are generally composed mostly of non-volumetric charges (e.g. demand charges) and therefore C/I customers are compensated less on a cents/kWh basis than residential customers.

TABLE 2: Historical Commercial and Industrial Net Energy Billing Rates (cents/kwh,nominal$)

	2013	2014	2015	2016
Standard Service Generation	8.29	10.28	11.38	9.149
Volumetric Energy Charges	2.21	1.98	1.20	1.62
Total Net Energy Billing Rate	10.51	12.26	12.58	10.77

Residential Net Metering Forecast

DEEP evaluated historical residential net metering rates, from 2008 through 2017 to forecast residential net metering rates from 2018 through 2049. The residential net metering forecast was developed by applying trending assumptions for individual rate components of the allowable charges that a distributed generation customer could offset. Some components, such as Transmission and Generation, were forecasted by using established trending assumptions detailed in the table below. Others, such as the Conservation, CTA, SBC, etc., were kept constant

[1] CGS 16-243H
[2] Weighted Average of Eversource and United Illuminating

throughout the forecast period because they are relatively small and further assumptions would need to be made with regard to state policy changes in order to change the current rates for these components (e.g., conservation).

TABLE 3: Residential Net Metering Rate Forecast Trending Assumptions

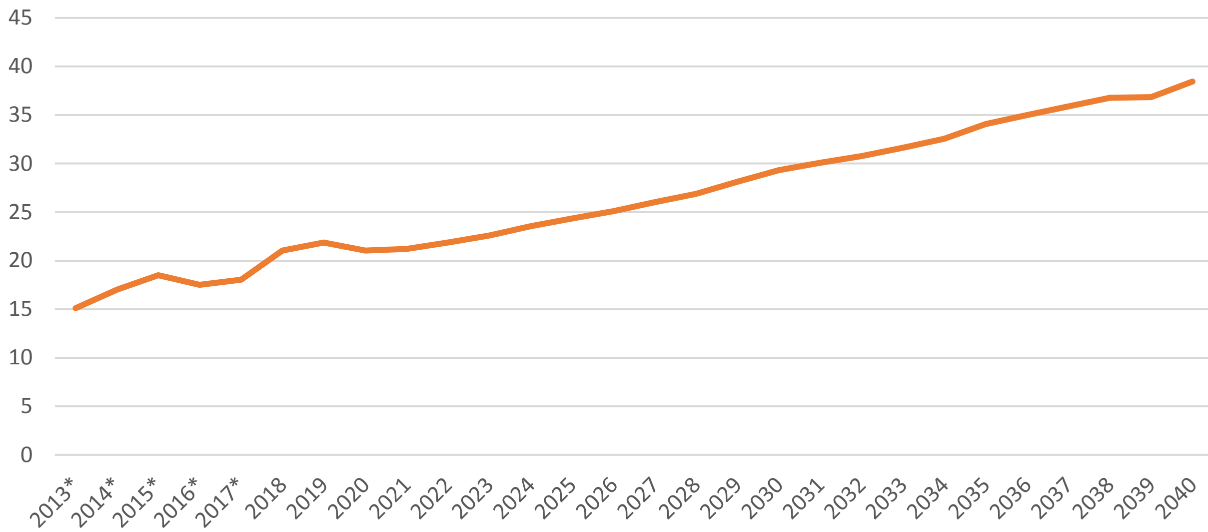
Category	Trending Assumptions
Distribution	Inflation + 2%
Transmission	EIA 2017 Transmission Cost Forecast [3]
Generation	EIA 2017 Generation Price Forecast [4]
Decoupling	Inflation + 2%
NBFMCC	Inflation
Conservation	Constant
CTA	Constant
SBC	Constant
Renewables	Constant
CAM	Constant

Increases in distribution costs were assumed to be a result of inflation and additional investments that the EDCs would have to make in their service territories. DEEP further assumed that decoupling charges were linked to lost revenues in distribution based charges, and therefore were linked to distribution costs. DEEP found that on average, the annual increase in distribution charges has been around 7% (2008 through 2017). However, during some years distribution charges increased more than 20% due to a recent rate case and in other years such charges did not increase from the previous year. DEEP determined that using an annual increase of 4% (Inflation of 2% and a 2% adder) would be a reasonable approach in estimating future distribution rates without overestimating ratepayer costs of distribution and decoupling charges.

FIGURE 4: Residential Net Metering Forecast (Nominal$, 2013-2040, cents/kWh)

[3] Table 55.5 Electric Power Projections by Electricity Market Module Region, Prices by Service Category, Transmission, Nominal Dollars

[4] Table 55.5 Electric Power Projections by Electricity Market Module Region, Prices by Service Category, Generation, Nominal Dollars



Commercial and Industrial Net Metering Forecast

DEEP evaluated the commercial and industrial net metering rates from 2013 through 2016, or the time period that the Low and Zero Emissions Renewable Energy Credit (LREC/ZREC) program has been in place. In contrast to the estimation of net energy billing rates for residential customers, DEEP took a more simplified approach in estimating C/I net energy billing rates. Given the complex structure of C/I rates, the net energy billing rates needed to only reflect volumetric based charges and exclude any customer charges and demand based charges. Under this approach, DEEP made the following assumptions:

(1) A customer's maximum demand does not change even with on-site generation being available. This could occur because the customer's maximum demand occurs outside of the time such customer is generating on site power. For example, in the case of PV generation, if the customer's maximum demand occurs at night, then their maximum demand is completely unaffected by PV generation because the system can only generate power when the sun is shining.[5]

(2) However, a customer's maximum demand could occur during the day and be offset by PV generation. For example, if a customer's maximum demand is 10 kW and they produce 2 kW of on-site generation, then their net demand would be 8 kW. Let's further suppose that the Transmission Demand charge is $6/kW and the Distribution Demand Charge is $12/kW. The cost to the customer (only for transmission and demand charges) based on their original demand should have been $180. However, with PV generation they have in effect lowered their demand charges to $144 because they netted out 2 kW using PV generation. In this situation, the customer is paying less towards the grid than what should

[5] This assumes that no on-site storage of any kind is available

have been paid and there is some cost-shifting to other ratepayers in the short term because the distribution investments to serve that customer are already in place. However, as a matter of policy, DEEP believes that customers should be incentivized to reduce their demand on the system, whether it be by conservation or on-site generation. In addition, because of the way C/I rates are structured (i.e., incorporating demand based charges) these types of customers are not easily able to offset their entire bill through net energy billing in the same way that residential customer are able to. For these reasons, in calculating the direct cost of C/I net energy billing, only volumetric and standard service generation rates were considered. The volumetric based charges are considered to be shifted costs to non-participating ratepayers, while the standard service generation charges are considered the direct benefits.

DEEP ultimately chose to use the trending assumption in Table 5 for C/I net energy billing rates. Volumetric charges are composed mainly of distribution, transmission, and other combined public benefit charges (e.g., NBFMCC, C&LM, etc.), but are generally small overall because the majority of delivery costs are collected through demand based charges.

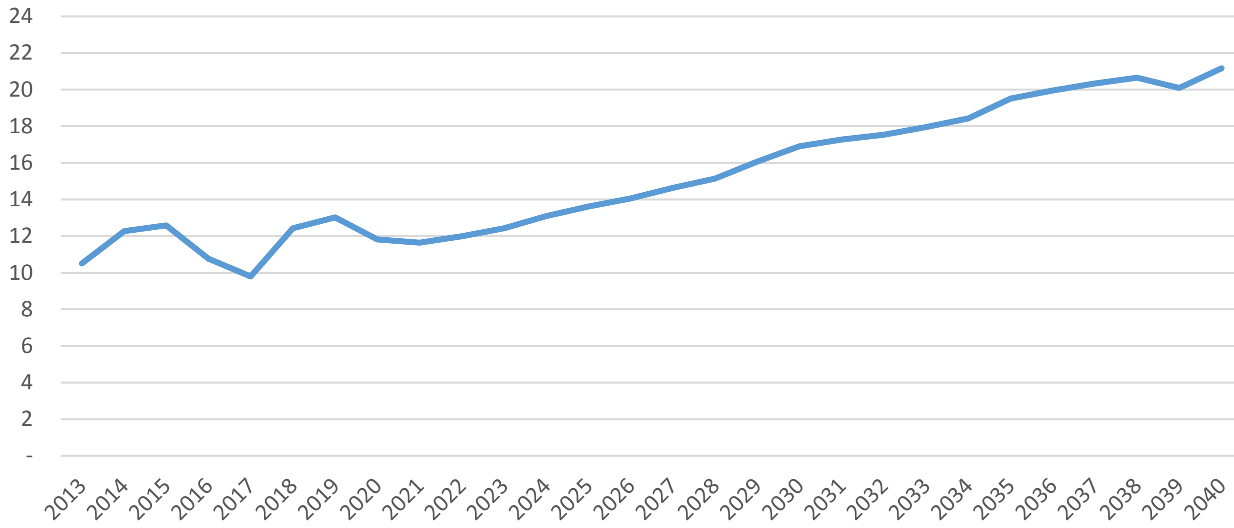
The EIA 2017 Commercial/Industrial Electricity Price forecast was used as the trending assumption for the volumetric charges. Although the EIA 2017 C/I Electricity Price forecast incorporates generation-based charges in prices, DEEP believed that this was the best available trending forecast for these particular charges and attempting to use a high level analysis. The EIA AEO 2017 Generation Price Forecast was used as the trending assumption for Connecticut generation prices.

TABLE 5: Commercial/Industrial Net Metering Rate Forecast Trending Assumptions

Category	**Trending Assumptions**
Volumetric Charges	EIA AEO 2017 C/I Electricity Prices Forecast
Generation	EIA AEO 2017 Generation Price Forecast [6]

[6] Table 55.5 Electric Power Projections by Electricity Market Module Region, Prices by Service Category, Generation, Nominal Dollars

FIGURE 6: Commercial and Industrial Net Metering Forecast (Nominal$, 2013-2040, cents/kWh)



Other Incentives for Renewables Generation

In addition to net metering, there are numerous other incentives that distributed resource customers can receive for installing clean energy resources and that add to the total cost of these programs. For the purposes of this evaluation, DEEP only considered the two largest programs in the state that promote the installation of distributed resources through monetary incentives that are being implemented at this time: (1) the Green Bank's Residential Solar Investment Program (RSIP) and (2) LREC/ZREC.

LREC/ZREC

Public Act 11-80 established the LREC and ZREC programs. Launched in the summer of 2012, this auction-structure provides an additional revenue stream to projects through long-term contracts for renewable energy certificates (RECs). The LREC program is available to low emission Class I renewables up to 2 MW. The ZREC program is available to zero emission Class I renewables up to 1 MW. Large ZRECs (250-1,000 kW) and Medium ZRECs (100-250 kW) compete in the auction, while Small ZRECs (under 100 kW) are offered a price with an adder based on the Large and Medium ZREC auction results. Under the LREC/ZREC programs, the EDCs purchase only RECs, not energy or capacity.

The ZREC program allowed for $720 million in total spending for renewable energy credits from zero-emission Class I renewable energy resources such as solar, wind, and small hydro to be spent over six years beginning in 2012. Beginning in 2012, EDCs must enter into $8 million worth of long-term (15-year) contracts annually for six years. The final competitive auction for this program was initiated in April 2017 and was completed in June of the same year. However, passage of Public Act 17-144 extended the ZREC program for one year for up to $4 million worth of long-term contracts.

The LREC program allowed for $300 million in total spending for renewable energy credits from low-emission Class I resources such as fuel cells, biomass, and landfill gas that meet certain emissions standards over five years beginning in 2012. The LREC program requires the EDCs to enter into $4 million worth of 15-year contracts annually for LRECs for five years, beginning in 2012. The LREC program, originally authorized until 2016, was extended for one additional year by the General Assembly with the passage of Public Act 16-196, which split the $8 million allocated to the final year of ZREC equally between the LREC and ZREC programs. Public Act 17-144 extended the LREC program for an additional year for up to $4 million worth of long-term contracts.

DEEP estimated that through Year 5 of the LREC/ZREC program, the EDCs have committed approximately $759 million of the $1.02 billion lifetime budget. This would leave about $260 million total remaining for LREC/ZREC projects for the term of the 15-year contracts, as demonstrated in Table 7. In our analysis, DEEP apportioned the remaining funds ($130 million) to Year 6 of the program. Lastly, for Year 7 in Table 8, DEEP apportioned an additional $120 million, split evenly between LREC and ZREC project, which is the cumulative cost of 15 year contracts with an annual budget of $8 million.

TABLE 7: LREC/ZREC Lifetime Budgets and Committed $ Through Year 6

Program	Lifetime Budget	Lifetime $ Committed	Lifetime $ Not Yet Committed for Year 6
ZREC	$ 720,000,000	$ 473,367,156	$ 130,435,548
LREC	$ 300,000,000	$ 285,761,747	$ 130,435,548

TABLE 8: Estimated LREC/ZREC Annual and Lifetime Budgets for Year 7

Program	Annual Budget for Year 7	Lifetime Budget for Year 7
ZREC	$4,000,000	$ 60,000,000
LREC	$4,000,000	$ 60,000,000

DEEP further calculated the weighted average cost of LREC/ZREC projects by only accounting for projects that are were operational or approved but not yet terminated. REC contracts that were terminated were not included in any funding or price calculations.

TABLE 9: Actual and Estimated LREC/ZREC Weighted Average Cost (Years 1-7)

	Year 1 (2012)	Year 2 (2013)	Year 3 (2014)	Year 4 (2015)	Year 5 (2016)	Year 6 (Projection) (2018)	Year 7 (Projection) (2019)
LREC Prices ($/REC)	66.86	53.05	56.15	50.46	42.57	41.33	41.33
LREC Annual Change (Percentage)		-21%	6%	-10%	-16%		
ZREC Prices ($/REC)	133.23	95.36	71.59	67.57	75.53	73.34	73.34
ZREC Annual Change (Percentage)		-28%	-25%	-6%	12%		

For Years 1 through 5, DEEP used the actual bid price information provided by the EDCs. In this analysis, the projected price for Year 6 is the average executed contract price for LREC/ZREC bids in Round 1 of Year 6. An additional round will be conducted for Year 6, but such prices are unknown since they had not yet been submitted to PURA at the time of DEEP's evaluation.

The projected price for Year 7 is assumed to be the same prices of executed bid prices in Round 1 of Year 6. LREC/ZREC prices are set entirely by bidders in the reverse auction. Overall, the lower the bid the more likely a project will be chosen, so bidders are incentivized to bid low. However, because of the erratic year to year average price changes for LREC/ZREC contracts, it is very difficult to predict the near term prices for the bids. Moreover, in recent rate cases, rates for C/I customers have been restructured to collect more of their costs through demand charges rather than volumetric charges. Hence, the net energy billing compensation is lower than it was previously. In turn, DEEP assumed that bidders may actually need to compensate for lower net energy billing subsidies through higher ZREC prices if installed costs do not come down. If installation costs do come down, DEEP believes that bidders may actually bid at the same levels to compensate for lower subsidies elsewhere. In addition, in the Round 1 of Year 6 solicitation, the percentage differential between overall bid prices and executed bid prices were generally higher than in the previous year, which may indicate that bidders are generally bidding higher than in recent years. In order to balance all these variables, DEEP assumed that at least in Year 7, LREC/ ZREC prices would likely stay the same. ZREC prices for the most part are generally trending upward, but historically ZREC and LREC prices have come down since the inception of the program.

Table 10: Year 6 – Round 1 Prices ($/REC)

	Large ZREC	Medium ZREC	LREC
Executed Contract Prices	$ 64.42	$ 98.76	$ 44.49
Overall Bid Prices	$ 74.31	$ 113.74	$ 51.98
Percent Above Executed Bid Price	15.4%	15.2%	16.8%

LREC/ZREC prices, from 2021 through 2030, were forecasted by applying the trending assumptions in the REC Market Price Forecast. For the purposes of this analysis, DEEP assumed that LREC/ZREC prices would change proportionally with forecasted market prices for Class I RECs. The Class I REC market price forecast was thought to be the best assumption, since it takes into account a supply and demand approach for RECs as well as future price trajectories for installed costs of clean energy and renewable technologies. For example, REC prices are projected to increase in 2022 due to the expiration and reduction in solar tax incentives for residential and C/I projects.

Table 11: Year 6 – Round 1 Prices ($/REC)

Projected LREC/ZREC Prices – Average of All Sizes ($/REC)										
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ZREC Prices	73.15	84.29	82.42	83.39	80.61	74.67	69.75	64.92	58.22	50.11
LREC Prices	35.12	40.47	39.57	40.03	38.70	35.85	33.49	31.17	27.95	24.06

Green Bank Subsidies

The Connecticut Green Bank offers Expected Performance Based Buy-Down (EPBB) and Performance Based Incentives (PBI) programs.

The EPBB incentive is only available to Homeowners choosing to purchase a PV system from an Eligible Contractor. The Eligible Contractor must present the EPBB as an upfront cost reduction to the customer. The Green Bank issues the EPBB payment directly to the Eligible Contractor on behalf of the homeowner at completion of the installation and upon Green Bank verification of submitted completion documents.

The PBI is only available to System Owners under a third-party financing structure (i.e. lease or power purchase agreement (PPA). Under the PBI, homeowners will contract with Eligible Contractors and/or Third Party System Owners to provide a solar PV system. The PBI is paid to the System Owner over twenty-four (24) calendar quarters (e.g. 6 year term) following a passing Green Bank inspection and is based on actual production at a per kWh rate specified at the time of RSIP project/incentive approval. System Owners are expected to build the expected total PBI into the lease or PPA rate to the customer.

For the existing programs and expected projects to come online (2013 through 2020), DEEP used the following incentive rates based on information received from the Green Bank:

TABLE 12: Green Bank Expected Performance Based Buy-Down, 2012-2020

EPBB Incentive ($/kW)								
2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
1,606	1,221	912	514	432	417	403	389	376

TABLE 13: Green Bank Performance Based Incentives, 2012-2020

<table>
<tr><th colspan="14">PBI Incentive (cents/kwh)</th></tr>
<tr><th></th><th>3/1
2012</th><th>5/1
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2013</th><th>1/1
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<tr><td><=20kw</td><td></td><td></td><td></td><td></td><td>6.0</td><td>6.0</td><td>6.0</td></tr>
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Locational Marginal Price Forecast

The Locational Marginal Prices (LMP) price forecast were used mainly for calculating the direct benefits of grid scale projects. This works by comparing the energy price in the contract between the EDCs and the project developers against the forecasted LMP price. To the extent the contract price is below the forecasted price, ratepayers will receive a direct benefit. These LMP price forecast was developed for use in the Public Act 15-107 Procurements and DEEP chose to use this forecast in its CES analysis.

REC Price Forecast

The annual REC price forecast used in the CES analyses were produced by Navigant, for the Clean Energy RFP, and adopted by LAI for use in the procurement authorized under P.A. 15-107 Section 1(b) (2-20 MW renewable resources).

The underlying assumption of the REC price forecast model is that the REC revenues represent the additional revenue stream needed to finance and develop a new wind resource, after accounting for energy revenues and production tax credits. The revenue requirements model assumes that the REC market is in equilibrium over the long term: that is, neither a shortfall nor surplus of RECs.

The REC price forecast model assumes that the REC supply equals the REC demand in each year. From year to year, the market may fluctuate between an oversupply and an undersupply condition, for a variety of reasons. For example, renewable resources are “lumpy,” creating a temporary oversupply when added to the system; the in-service date of a new project may be delayed; certain entities may hold a surplus of banked RECs, investor uncertainty regarding the extension of the federal production tax credit; and regulatory or statutory changes in the RPS requirement or eligibility may change from year to year, changing the supply/demand balance. These short-term fluctuations cannot be predicted over a 20+ year forecast. An equilibrium forecast best represents the expected price trajectory over the long term.

The REC price forecast was prepared in January 2016 for the Clean Energy RFP when Class I RECs in both Connecticut and Massachusetts were trading in the $50 range. However, during the fourth quarter of 2016 and the first quarter of 2017, Class I RECs were trading in the $20 to $30 range. DEEP chose to use the REC forecast from the Clean Energy RFP for this analysis, despite the recent short-term market changes at the time of preparing the forecast.

In DEEPs analyses, the REC price forecast were used mainly for calculating the cost of RECs to comply with Connecticut's RPS requirements and ultimately generate the RPS costs in the Renewable Portfolio Standard Costs section of the Electric Power Chapter, net of RECs already generated through Connecticut's behind the meter and grid scale programs. DEEP assumed that state sponsored programs that generated Class I RECs would need to be deducted from the total RPS requirement since ratepayers would be paying for those RECs through ratepayer subsidies (i.e., Green Bank incentives, LREC/ZREC contracts, Utility built projects, or long-term PPAs). Hence, the cost of the REC is already embedded in the direct cost of those programs, even though the typical practice is for the REC purchasers in the LREC/ZREC and RSIP programs to re-sell them into the market rather than settle them on behalf of Connecticut ratepayers. For example, if the RPS required 20% of load to be met by Class I RECs, then about 5,500,000 RECs would need to be purchased.[7] If behind the meter programs (e.g., RSIP and LREC/ZREC) produced 1 million RECs and Grid Scale projects (e.g., Section 127, Small Scale Procurement, etc.) also produced 1 million RECs, then 3.5 million RECs would still need to be purchased elsewhere in the market to meet the RPS requirement. Therefore, if the REC price in that year was $50, then the total ratepayer cost of Class I market RECs would be $175 million.[8]

Cost Benefit Assumptions for Calculating Net Direct Ratepayer Costs

Cost and Benefits Used in CES Analysis

DEEP calculated the annual Net Direct Ratepayer Costs by taking the difference between the annual Direct Costs and Direct benefits. Environmental benefits are embedded in the RECs, which represent the environmental attribute associated with the clean generation. This does not take into account indirect costs and benefits like health, quality of life, etc.

Direct Costs

[7] For hypothetical purposes this assumes a total EDC load of 27,500,000 MWH.

[8] These numbers are for illustrative purposes, they do not reflect the actual costs and REC requirements in DEEP's analysis. The $175 million dollar figure is the product of purchasing 3.5 million RECs at $50 in any given year.

- In DEEP's analysis, the Direct Cost are essentially the subsidies that are paid out by ratepayers or subsidies that are received by participants in behind the meter or grid side programs.

    - In the case of behind the meter programs, participants can receive a REC subsidy, but can also use net energy billing to offset their volumetric charges. Therefore, the Direct Cost for behind the meter programs were assumed to be the annual costs of REC subsidies and the cost of all net metering credits generated.

    - With regard to grid scale programs, the direct costs vary with each program and/or project. If a project was built directly by a utility the Direct Cost would be the capital and O&M cost of the project over a 20 year period. However, in most of Connecticut's grid scale programs, participants enter into long term contracts (i.e., power purchase agreements) for energy and/or RECs. If a project was procured through a PPA, the Direct Cost is the fixed contract price for each unit of generation. Generally, most PPAs purchased both the energy and RECs . However, some PPAs only contracted for RECs and not energy. Grid scale program participants are generally not allowed to use net energy billing or be a recipient of any other ratepayer subsidies. In addition, to date grid scale programs have required projects to be at least 2 MW in size. However, the Shared Clean Energy Facilities (SCEF) pilot program allowed developers to submit proposals for projects less than 2MW, but these participants were not allowed to use net energy billing.[9]

Direct Benefits

- Direct Benefits were defined as the avoided utility costs that pertain to generation.

    - In calculating the Direct Benefits of behind the meter programs, the Standard Service Generation Rate was considered to be the quantifiable direct benefit of generation. Standard service rates are generally the aggregate cost to procure a firm supply of energy, capacity, ancillary services, RPS compliance, risk management, overheads, etc. DEEP recognizes that there are certain fixed costs (e.g., capacity costs) that are embedded into retail Standard Service Generation rates and that using this rate is perhaps an overestimation of the generation benefits. However, the majority of the embedded costs in the Standard Service Rates are composed of energy and capacity costs, the latter of which is avoidable in long run, and the other costs are generally small in comparison. Therefore, for simplicity, DEEP decided to use the Standard Service Rate, rather than arbitrarily choosing to only offset a portion of such rates.

    - In calculating the Direct Benefits of grid scale programs, DEEP needed to consider whether each project was purchasing energy and RECs.

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[9] The Direct Costs and Direct Benefits of the SCEF program were not included in DEEP's analysis, given that the projects are relatively small and it is a Pilot Program.

- For projects where the EDCs retained or purchased energy and RECs, the Direct Benefit was considered solely to be the Locational Marginal Price at the time the generation was produced.

- For projects, where only RECs were purchased or retained, DEEP did not include direct benefits. The RPS compliance framework requires ratepayers to have RECs generated or purchased on their behalf, therefore, the cost to generate the REC or purchase the REC is fully borne by ratepayers.

DEEP only considered the following programs in calculating the Net Direct Ratepayer Cost since these programs encompass the majority of ratepayer sponsored programs.

TABLE 14: Direct Costs and Benefits Included in Net Direct Ratepayer Cost Based on Program

Program	Energy/REC Incentive	Other Ratepayer Subsidies		Direct Costs	Direct Benefits
RSIP	For purchased solar installations, homeowners are paid upfront incentives for each kW of the PV installation. For leased projects, the developers are paid a performance based incentive (PBI) for each kWh of generation; this incentive is generally paid out in 6 years, however, previously it was paid out in 5 years.	RSIP participants are allowed to use Net Energy Billing indefinitely.		(1) The RSIP subsidy was considered to be a cost to the RPS in the year that the incentive was paid out. For example, if upfront incentives totaled $500,000 in one year, then that amount was considered a cost to the RPS for that year. For performance based incentives, only the first year of the PBI incentive would be a cost to the RPS in any given year. The cost for the remaining years would be allocated to the following 5 years accordingly. (2) The Net Energy billing rate was assumed to be a direct cost that would continue indefinitely and was calculated based on the expected generation from the PV installations.	Residential Standard Service Generation (Weighted Average of CL&P and UI).

LREC/ZREC	The EDCs purchase RECs from bidders in a reverse auction. The bids are based on the maximum annual RECs that a project can produce. These contracts are for 15 years.	LREC/ZREC participants are allowed to use Net Energy Billing indefinitely.		(1) The LREC/ZREC subsidies were considered direct costs and were allocated in the year in which the RECs were expected to be generated over a period of 15 years. No further REC subsidies are considered once a contract's term has expired. (2) (2) The Net Energy billing rate was assumed to be a year direct cost that would continue indefinitely and was calculated based on the expected generation from the PV installations.	Commercial and Industrial Standard Service Generation (Weighted Average of CL&P and UI).
Section 127	Section 127 projects are a mix of utility owned projects and PPA contracts with third party developers.	None		The Direct Costs vary: (1) Utility built projects: Direct costs are the levelized 20 year cost. Capital and O&M costs were levelized based on the expected generation. (2) PPA Contract Projects: Projects that were procured via long term contracts with third party developers had established fixed price over 20 year in each contract.	Wholesale LMP
Section 6	Long Term PPA Contract was executed for Energy and RECs. The EDCs own both the energy and REC attributes of the projects. The contract has a term of 20 years.			(2) PPA Contract Projects: Projects that were procured via long term contracts with third party developers had established fixed prices over 20 year in each contract.	Wholesale LMP

Project 150	PURA approved long term contracts for certain projects. Projects were established prior to the creation of DEEP. Of the projects that were approved, only three remain. The price of each project may vary each year based on inflation or a fuel price adjustment.	None		The cost of the PPA, adjusted for inflation or fuel costs in any given year.	Wholesale LMP
Section 8	Long Term PPA Contracts were executed for RECs only. The developer retained rights to the energy portion of the generation. The term of the contract varies by project.	None		The cost of the PPA Contract for RECs only.	None
Small Scale Procurement (Energy and REC Projects)	Long Term PPA Contracts were executed for Energy and RECs. The EDCs own both the energy and REC attributes of the projects. All had a term life of about 20 years.	None		The cost of PPA contract for Energy and RECs.	Wholesale LMP
Small Scale Procurement (REC Only Projects)	Long Term PPA Contracts were executed for RECs only. The developer retained rights to the energy portion of the generation. All had a term life of about 20 years.	None		The cost of PPA Contract for RECs only.	None
Large Scale Procurement (Energy and REC Projects)	Long Term PPA Contracts were executed for Energy and RECs. The EDCs own both the energy and REC attributes of the projects. All had a term life of about 20 years.	None		The cost of PPA contract for Energy and RECs.	Wholesale LMP

Cost and Benefits Not Considered in CES Analysis

DEEP recognizes that distributed energy resources can possess other benefits than those considered above, which may include avoided T&D costs and reliability, and economic development benefits.

Economic Development Benefits

Economic development benefits are defined as the net economic impact from increase solar integration. Variables that would cause a positive net economic impact would be increases in state Gross Domestic Product (GDP), tax revenue, and private sector jobs. Variables that would have a negative economic impact would be higher electricity that result from higher costs of renewable generation. Higher electricity rates would mean that ratepayers would have spent less elsewhere, thereby causing a negative economic impact and possibly a reduction in private sector jobs overall.

Transmission, Distribution, Reliability, and Location Benefits

In certain circumstances, distributed generation can provide variety of benefits to the electric system, including reliability, transmission, distribution and location benefits. Reliability benefits are defined as times in which distributed generation provides benefits to the electric grid in time of peak demand Transmission and distribution benefits are thought to be the result of investments that are otherwise being delayed or avoided because behind the meter generation will reduce the overall load and those investments will not be needed. However, in the absence of storage or back-up power pairing, the performance characteristics of distributed generation sources like solar PV do not necessarily support the argument that these systems should not be paying for transmission, distribution, or reliability costs.

For example, PV systems generally produce electricity early in the mid-day and early afternoon, but Connecticut's electric load demand curve has a peak later in the day. In other words, PV does not appear to generate electricity in times of peak demand and thereby provide reliability benefits. Given that PV systems have a high level of variability, they are generally reliant on the electric grid for power in times when they are not generating electricity (e.g., a cloudy day or at night). Unlike microgrids, PV systems are generally not installed with storage or back-up power, leaving the electric grid to continuously provide grid support such as voltage regulation and frequency regulations. PV systems cannot provide electricity to the customer or the grid during a power outage because PV relies on the electric grid for start-up power and other power services.

In addition, a majority of the capital expenditures into Connecticut's current electric system is for reliability improvement and storm preparation, rather than transmission and distribution system improvements, which would likely be necessary investments regardless of the amount of distributed generation.

Solar PV can be located in places where there is high demand and reduce the load demand curve for certain areas along the distribution system, but this analysis requires a level of granular detail of the distribution system that is not currently publicly available and depends upon whether the solar PV production coincides with peak demand in that location, which may require the addition of an energy storage system. It is difficult to quantify precise distribution benefits provided by an individual unit of distributed generation because the locational benefits are closely tied to the specific location of the distribution system. The unit may provide significant locational benefits in one area, but may also increase costs on the distribution system in another area. This analysis does not look at certain locations to find the highest value, but rather it looks at the state as a whole to find a widespread value. Additional input from the EDCs will be necessary to evaluate locations within the state that would be best suited for PV. However, a more prudent approach would be to simply identify specific locations and offer those participants an adder to the compensation they receive for generation rather than trying to determine a state-wide locational benefit value.

Other Utility Costs for Consideration

In addition to the benefits distributed generation may provide to the electric grid, such resources may also impose costs on the electric system that are not collected from participants. These costs are generally related to interconnection, integration, and backup services. For example, a PV system relies on the electric grid during operation; the PV system uses the electric grid to balance PV output by constantly maintaining the appropriate voltage and frequency when the sunlight intensity varies throughout the day. When the PV facility is not operating, the participant relies on the grid for backup power. Moreover, significant additions to solar PV capacity may require additional upgrades to the electric grid (T&D infrastructure) to ensure reliability. Connecticut currently requires that generators pay the full cost of interconnection, but there are no backup or standby rates and no fees to charge generators for integration costs. To the extent these costs are not recovered from participating distributed generation customer, they must be considered a cost or negative benefit in any cost benefit analysis since such resources will result in higher electric system costs for all ratepayers.

Cost of Existing RPS targets

The cost of the RPS as presented in the Renewable Portfolio Standard Costs section of the Electric Power Chapter is the Net Direct Ratepayer Costs for existing programs and projects that are expected to come online in the next few years, as well as the Cost of Purchasing Class I RECs on the market to fulfill the 20% RPS requirements by 2020. For example, generation procured under Project 150 and projects in service through the RSIP program are considered existing projects. Expected projects would be those in the large and small scale procurement and capacity expected to come online from the RSIP and LREC/ZREC program as projects become operational in the next few years. Cost associated with proposed programs (i.e., renewable tariff) and expansion of the RPS (i.e., 40% by 2030) were not included in such calculations. Lastly, as mentioned above, the REC price forecast was mainly used for calculating the cost of RECs to comply with Connecticut's RPS requirements, net of RECs already generated through Connecticut's behind the meter and grid scale programs. The sum of the Net Direct Ratepayer Cost of behind the meter and grid side programs (existing and expected), and the Cost of Class I Market RECs make up the cost of the RPS in DEEP's analysis. The cost of Class II or Class III RECs were not considered in any part of this analysis.

Distributed Generation Expansion Analysis

In order to determine the ratepayer impact of distinct policy options for expansion of distributed generation in Strategy 4 of the CES, DEEP needed to proportionately compare the various programs in terms of ratepayer costs. DEEP implemented various assumptions that it believes are reasonable to determine cost to ratepayers but also the tangible benefits that behind the meters programs provide. DEEP analyzed the results of these options and recommended one that will aggressively expand distributed generation opportunities for Connecticut's families and businesses, but also minimize any ratepayer bill impacts and make the subsidies as transparent as possible.

DEEP evaluated three main sets of policy options. The first set was a Business as Usual Approach, where all current policies continue and distributed generation annual procurements are expanded through 2030. The second assumed a similar expansion of all current policies, including the existing net metering structure, but included caps. The third set of policy options required the implementation of a Renewable Energy Tariff from 2021 to 2030, subject to a year to year budget limitation.

In the distributed generation expansion analysis, DEEP only considered the costs and benefits of new capacity that is brought online through each of the scenarios explained below. Cost and benefits for projects that may come online after 2021, but were funded by existing programs like the final years of LREC/ZREC or RSIP, are not included in any part of this analysis.

Assumptions

In order to properly compare the cost, benefits and estimated deployment effects of the different approaches for behind the meter expansion, DEEP needed to implement reasonable assumptions and timeframes in its analysis.

General Assumptions

1.) **Evaluation period:** The time period evaluated was 2021 through 2049. Under the Business as Usual Approach, projects and contracts would come online and be executed from 2021 through 2030. Under the Budget Based Approach, contracts would be executed from 2021 through 2030 and projects would come online in the same year the contract was executed.

2.) A 5% discount rate was used to calculate the Net Present Value (NPV) of total Program and Ratepayer Costs

3.) **Capacity factors:** Only Solar (15% Capacity Factor) and Fuel Cell (95% Capacity Factor) projects were considered in this evaluation, given that they are the predominant technologies in the Behind the Meter market in Connecticut.

4.) **Installation and customer types:** Three types of participants were considered based on the types of installations that Residential and C/I customers choose to make:

   a. Residential Solar
   b. C/I Solar
   c. C/I Fuel Cell

Assumptions for Business as Usual and Capped Net Metering Approaches

1.) One Business as Usual approach was evaluated:[10]

   a. Business as Usual

      i. Under this approach, the Green Bank Subsidy would be expanded through 2030, with an installation target of about 32 MW per year. In addition, the LREC/ZREC program would be expanded from 2021 to 2030, with the same $8 million annual spending target and 15 year REC contracts. Net Metering would also continue indefinitely for all residential, commercial, industrial projects. A virtual net metering expansion was not included because, unlike the annual auctions for LREC/ZREC and steady pace of growth under RSIP, the virtual net metering program is not ongoing and, thus, it was difficult to estimate a reasonable expansion of the program.

2.) Two Capped Net Metering approaches were evaluated:

   a. Behind the Meter Cap at 2.5%

      i. Under this approach, the state would allow new BTM projects to represent 0.25%/year for a cumulative 2.5% cap in 2030. For this analysis, each sector (Residential Solar, C/I Solar, and C/I Fuel Cell) would be allocated 1/3 of the annual cap. Residential projects would continue to receive state subsidies and C/I projects would continue to receive a REC subsidy through the LREC/ZREC program, however annual spending for LREC/ZREC would never exceed the amount needed to reach the annual percentage cap for each sector. Net Metering would also continue indefinitely for all residential, commercial, industrial projects. Similar to the Business as Usual approach, a virtual net metering expansion was not included in the assumptions.

   b. Behind the Meter Cap at 5%

      i. This approach is similar to the 2.5% cap, however the annual cap would be 0.5% for a cumulative 5% cap in 2030.

3.) DEEP assumed the following incentives:

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[10] The same forecasted LREC/ZREC prices were used in all three Business as Usual approaches.

a. Net Metering would continue as it does now, so Residential and C/I customers would continue to net their consumption with production indefinitely.

b. For the forecast period of 2021 through 2030, DEEP assumed that the Green Bank subsidies would continue. DEEP further applied the existing subsidy reduction rates provided by the Green Bank for the existing EPBB and PBI programs to the 2021-2030 forecast period. The amount of the EPBB subsidy would be reduced by 3.4% each year and the PBI incentive would be reduced by 10% each year.[11] EPBB incentives are paid out upfront and PBI incentives are paid out in 6 year terms. In addition, 25% of RSIP capacity would be completed through the EPBB program and 75% would be installed through the PBI program.[12] For example, if 50MW were installed in one year through the RSIP program, 12.5MW would have been funded with EPBB incentives and 37.5MW would have been funded through PBI incentives.[13]

TABLE 15: Residential Solar Investment Program Subsidies - Expected EPBB and RSIP Rates (2021-2030)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RSIP EPBB ($/kW)	363	351	339	327	316	305	295	285	275	266
RSIP PBI (cents/kWh)	2.92	2.62	2.36	2.13	1.91	1.72	1.55	1.39	1.26	1.13

c. LREC/ZREC contracts would continue to be executed from 2021 to 2030 and subsidies are paid out in 15 year terms. The total amount spent is dependent on the scenario being evaluated.

4.) Load Share Assumptions were as follows:

a. Under the cap based approaches (e.g., 2.5% and 5%), DEEP allocated one-third of the expected annual load evenly between Residential Solar, C/I Solar, and C/I Fuel Cell.[14]

5.) Direct Costs and Benefits of the Business as Usual Approaches:

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11 Incentive reductions provided by the Green Bank

12 Breakdown of 25% and 75% provided by the Green Bank

13 The 25% and 75% breakdown only applies to the Existing Cost of the RPS and the Business as Usual scenarios. The BAU scenarios are explained later in this Appendix.

14 For example, if the target load in Year 1 is 0.5% (which would culminate in 5% of load in 10 years), then each sector would be allocated 0.17%. Assuming the load in that year was 27 million MWH, this would total about 70MW of Solar and 6 MW of Fuel Cell capacity.

a. Direct Costs would be the sum of net metering credits and any ratepayer subsidies (i.e., LREC/ZREC contract or Green Bank Subsidy)

b. Direct Benefits are the standard service generation rate for either a Residential or C/I customer

Assumptions for Budget Based Approach

1.) Three Budget Based Approaches were evaluated:

   a. $22.5 Million/Year

   b. $30 Million/Year

   c. $35 Million/Year

2.) The annual budget would be exhausted completely in one calendar year and no money is rolled over into the next year.

3.) Subsidies are paid out on a performance based basis similar to the existing LREC/ZREC program. During the forecast period the EDCs would be allowed to approve tariffs up to an annual maximum dollar basis for 20 year terms through a Renewable Energy Tariff Program. For example, if the annual maximum in one year is $22.5 million, then the 20 year Direct Cost of those contracts would be $450 million.

4.) The costs and benefits for the Renewable Energy Tariff Program were evaluated from 2021 to 2049. However, the tariffs would be executed from 2021 to 2030 to keep in line with the CES' focus on annual procurements through 2030. DEEP did not integrate any cost for new tariffs after 2030 to properly measure the lifetime effect of these 20 year contracts that would be executed in a 10 year timeframe.

5.) Funds are allocated by evenly splitting the total annual budget between Residential Solar, C/I Solar, and C/I Fuel Cell. For example, with a $22.5 million budget, each sector would be allocated approximately $7.5 million in that year alone.

6.) The Cost/Benefit used the following variables:

   a. Direct costs would be the tariff prices. For example, if the tariff price was $230/MWH, that full amount would be the Direct Cost.

   b. Direct Benefits is the standard service generation rate for either a Residential or C/I customers.

   c. The Net Direct Ratepayer Cost is the difference between the Direct Costs and Direct Benefits.

7.) DEEP established different level of compensation (including energy and RECs) for each type of participant. These levels were determined to be appropriate for the purposes of this evaluation, but may change if the programs are approved and implemented. For example, PURA could determine in its Decision that a higher or lower incentive is needed for Residential projects to make them cost-effective for the participants. In addition, the bids in the reverse auction for C/I participants may be higher or lower depending on the price ceiling that PURA establishes and the actual bids that are received. Considering that this was a high level analysis, DEEP attempted to use an average tariff prices for each type of participant, but recognizes that for certain participants the ownership model may be different. For example, residential solar, can be owned directly by the homeowner or can be leased to the homeowner by a third party-owner, therefore each may have a different tariff price.

TABLE 16: Average Renewable Energy Tariff Rates in $/MWH

Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Residential Tariff - Solar	214	249	242	234	227	220	214	207	201	195
C/I Tariff - Solar	184	207	201	195	189	183	179	173	168	163
C/I Tariff - Fuel Cell	158	154	150	145	145	145	145	145	145	145

a. DEEP estimated the Residential Solar Tariff based on the projected installed costs of residential solar and any associated financing and equipment replacement costs that a residential customer may incur. These costs also account for the expiration and reduction of federal incentives and tax credits. DEEP further considered that customers would not choose to install solar panels unless they received a reasonable rate of return on their investment. Therefore, for Residential PV systems, DEEP implemented a 20% adder as a Rate of Return to the total costs of purchased and leased system costs in each year from 2021 to 2030.

b. DEEP estimated the C/I Tariffs by evaluating the total subsides that are currently received by C/I participants in the LREC/ZREC program and Net Energy Billing, as well as accounting for the annual changes in capital and operational costs. DEEP used year 2016 as the benchmark starting point. For C/I Solar participants, DEEP used the annual change in residential PV system costs as the trending assumption. This trending assumption also accounts for any reductions in Federal Tax Incentives, which would result in a need for a higher tariff incentive. For the C/I Fuel Cell Tariff, DEEP applied the historical change in levelized Fuel Cell costs, which took into account capital and operational costs (i.e. variable O&M, fuel costs).

TABLE 17: Cost of a Purchased PV System v. Cost of a Leased PV System

Cost of a Purchased PV System										
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Total System Costs before Incentives	14.0	13.4	12.9	12.4	11.9	11.4	11.0	10.5	10.1	9.7
Financing Costs	3.2	4.0	3.8	3.6	3.5	3.4	3.2	3.1	3.0	2.9
Equipment Costs (Inverter and RGM)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Green Bank Incentive	1.6									
Federal ITC	3.1									
Total Gross System Cost	15.5	20.4	19.7	19.0	18.4	17.8	17.2	16.6	16.1	15.6

Cost of Leased PV Systems										
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Total Leased System Cost	18.8	21.1	20.5	19.9	19.3	18.7	18.2	17.6	17.1	16.6

TABLE 18: C/I Customer Trending Assumptions

Category	**Trending Assumptions**
Commercial Solar Customers	Annual % Change in Projected Residential PV Costs
Commercial Fuel Cell Customers	Historical Levelized Fuel Cell Costs - Average of High and Low Annual Change [15]

c. Further, the Commercial Fuel Cell Tariff was estimated by applying a simple average annual change of about -2.77%, which was derived from evaluating historical fuel cell costs from 2010 through 2017. Therefore, given the absence of additional cost trajectory data for fuel cell projects, the Commercial Fuel Cell Tariff was held constant after the year 2024.

[15] Fuel Cell Costs are referenced in "Lazard's Levelized Cost of Energy Analysis." DEEP used the Fuel Cell costs in Versions 4 thru 11. Lazard provides a low and high costs scenario for each technology. The annual percentage change in the low and high cost scenarios were for Years 2010 thru 2017 were averaged, respectively. This resulted in a -2.8% annual change in costs from 2010 thru 2017 when combining the low and high cost scenarios.

TABLE 19: Lazard's Levelized Cost of Energy Analysis, Fuel Cell, Versions 4 thru 11

	Year	Low Cost ($/MWH)	Annual % Change		High Cost ($/MWH)	Annual % Change	
Version 4	2010	111			241		
Version 5	2011	107	-4%		236	-2%	
Version 6	2012	109	2%		229	-3%	
Version 7	2013	109	0%		206	-10%	
Version 8	2014	115	6%		176	-15%	
Version 9	2015	106	-8%		167	-5%	
Version 10	2016	106	0%		167	0%	
Version 11	2017	106	0%		167	0%	

	Low Cost Average		High Cost Average		Average of High and Low Annual Change
Average % Change from 2010 thru 2017	-0.58%		-4.97%		-2.77%

Net Direct Ratepayer Cost of Behind the Meter Expansion

DEEP evaluated six different scenarios to determine what approach would provide the most cost-effective results to in procuring behind the meter resources from 2021 to 2030 while also mitigating cost-exposure to electric ratepayers. DEEP found that under a Business as Usual approach, where the RSIP and LREC/ZREC program were expanded through 2030 and net energy billing continued indefinitely, the Net Present Value (NPV) of the Net Direct Ratepayer Cost would be about $1.7 billion. DEEP also considered using a behind the meter cap of 2.5% (.25% per year) and 5% (.5% per year) of load. Under the 2.5% and 5% cap proposals, the NPV of Net Direct Ratepayer Cost would be substantially less, $600 million and $1.2 billion respectively, as compared with continuing to procure resources at the current pace. However, these approaches would result in much less renewable development. For example, under the Business as Usual Approach, the State would be on track to procure an additional 1,000 MW of new solar projects by 2030. Under the 2.5% cap the amount would be approximately 315 MW, and 630 MW for the 5% cap.

Lastly, DEEP evaluated the Budget Based Approaches, in style similar to the LREC/ZREC program. Under these Budget Based Approaches, the State would set an annual spending target to purchase generation from Class I resources. The three levels of spending evaluated were $22.5

million, $30 million, and $35 million. The NPV of the Net Direct Ratepayer Cost for these resources would be $275 million, $367 million, and $428 million over the life of the program, respectively. Under all of the Budget Based Approaches, the Net Direct Ratepayer Costs are significantly less when compared to the Business as Usual approaches. For example, the Net Direct Ratepayer Costs are about $1.3 billion less under the $35 million annual tariff program compared to the Business As Usual approach, while providing an additional 900MW of solar and 95 MW of fuel cells, which is a deployment amount close to the Business as Usual approach.

The amount of capacity that is procured under the Renewable Energy Tariff program is completely dependent on the actual tariff prices and may not actually reflect the amount of capacity expected to come online in this analysis. The higher the incentives, the less generation that can be purchased through the tariff based program because the programs are capped by a dollar amount. However, through competition and increased demand for renewables, DEEP expects that tariff prices will come down through the forecast period. Nevertheless, the tariff price is completely dependent on PURA's review and approval.

TABLE 20: Program and Ratepayer Costs (NPV) Under Six Scenarios

Scenario	Business as Usual	BTM Cap at 2.5%	BTM Cap at 5%	$22.5 Million/Year	$30 Million/Year	$35 Million/Year
Duration	Ongoing	Ongoing	Ongoing	20 Year Contracts	20 Year Contracts	20 Year Contracts
Program Cost (Millions)	$5,047	$1,549	$3,097	$1,964	$2,619	$3,055
Generation Value (Millions)	$3,322	$949	$1,897	$1,689	$2,252	$2,627
Net Direct Ratepayer Cost (Millions)	$1,725	$600	$1,200	$275	$367	$428

TABLE 21: Business as Usual - Estimated Installed Capacity and Percent of Load (2021-2030)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Solar - Residential	33	32	32	32	32	31	31	31	31	30	315
Solar - C/I	76	66	68	67	69	75	80	86	96	111	794
Fuel Cell - C/I	8	7	7	7	7	8	9	9	10	12	85
Percent of Load (Cumulative)	0.81%	1.55%	2.31%	3.08%	3.87%	4.73%	5.64%	6.62%	7.70%	8.94%	

TABLE 22: 2.5% Cap for Behind the Meter - Estimated Installed Capacity and Percent of Load (2021-2030)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Solar - Residential	16	16	16	16	16	16	16	15	15	15	157
Solar - C/I	16	16	16	16	16	16	16	15	15	15	157
Fuel Cell - C/I	3	3	3	3	2	2	2	2	2	2	25
Percent of Load (Cumulative)	0.25%	0.50%	0.75%	1.00%	1.25%	1.50%	1.76%	2.01%	2.27%	2.53%	

TABLE 23: 5% Cap for Behind the Meter - Estimated Installed Capacity and Percent of Load (2021-2030)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Solar - Residential	33	32	32	32	32	31	31	31	31	30	315
Solar - C/I	33	32	32	32	32	31	31	31	31	30	315
Fuel Cell - C/I	5	5	5	5	5	5	5	5	5	5	50
Percent of Load (Cumulative)	0.50%	0.99%	1.49%	1.99%	2.50%	3.01%	3.52%	4.03%	4.54%	5.06%	

TABLE 24: $22.5 Million/Year - Estimated Installed Capacity and Percent of Load (2021-2030)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Solar - Residential	27	23	24	24	25	26	27	28	28	29	261
Solar - C/I	31	28	28	29	30	31	32	33	34	35	311
Fuel Cell - C/I	6	6	6	6	6	6	6	6	6	6	61
Percent of Load (Cumulative)	0.47%	0.92%	1.40%	1.89%	2.40%	2.93%	3.47%	4.03%	4.61%	5.22%	

TABLE 25: $30 Million/Year - Estimated Installed Capacity and Percent of Load (2021-2030)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Solar - Residential	36	31	31	32	34	35	36	37	38	39	348
Solar - C/I	41	37	38	39	40	41	43	44	45	47	415
Fuel Cell - C/I	8	8	8	8	8	8	8	8	8	8	81
Percent of Load (Cumulative)	0.63%	1.23%	1.86%	2.52%	3.20%	3.90%	4.63%	5.38%	6.15%	6.95%	

TABLE 26: $35 Million/Year - Estimated Installed Capacity and Percent of Load (2021-2030)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Solar - Residential	41	36	37	38	39	40	42	43	44	46	406
Solar - C/I	48	43	44	45	47	48	50	51	53	55	485
Fuel Cell - C/I	9	9	9	10	10	10	10	10	10	10	95
Percent of Load (Cumulative)	0.74%	1.44%	2.17%	2.94%	3.73%	4.55%	5.40%	6.27%	7.18%	8.11%	

Ratepayer Bill Impact of Behind the Meter Expansion

For the purposes of this analysis, the ratepayer impact is essentially the Net Direct Ratepayer Cost, which is the difference between the Direct Costs and Direct Benefits. It is further assumed that the Net Direct Ratepayer Costs of the Renewable Energy Tariff would be collected through a volumetric charge embedded in rates (i.e. the Non-Bypassable FMCC). DEEP calculated the ratepayer bill impact on a volumetric ($/kWh), monthly basis ($/month), and annual basis ($/year).[16] The volumetric bill impact is calculated by taking the Total Annual Direct Ratepayer Costs and dividing it by the Expected Electric Load in the same year. For example, if the Net Direct Ratepayer cost is $100 million and the expected load is 27.5 million megawatt hours, the volumetric ratepayer impact would be $0.0036/kwh or 0.36 cents/kwh. The residential monthly bill impact would be calculated using the expected monthly consumption for a typical residential customer. For instance, if the expected usage in a month is 700kwh and the expected charge is $0.0036/kwh, then the cost to a typical residential customer would be an additional about $2.54/month or about $30.48/year.

TABLE 27: Average Bill Impact (cents/kWh) by Year Across All Ratepayers

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Business as Usual	0.075	0.140	0.208	0.277	0.350	0.427	0.504	0.585	0.674	0.769
2.5% Cap	0.028	0.051	0.075	0.100	0.125	0.151	0.176	0.201	0.226	0.253
5% Cap	0.055	0.101	0.149	0.199	0.250	0.302	0.351	0.401	0.452	0.505
$22.5 Million/Year	0.040	0.080	0.120	0.140	0.170	0.190	0.200	0.210	0.200	0.170
$30 Million/Year	0.050	0.110	0.160	0.190	0.230	0.250	0.270	0.280	0.260	0.230
$35 Million/Year	0.060	0.120	0.180	0.220	0.260	0.300	0.320	0.330	0.300	0.270

TABLE 28: Average Residential Monthly Bill Impact ($/Month) by Year[17]

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Business as Usual	$0.53	$0.97	$1.43	$1.89	$2.38	$2.87	$3.36	$3.87	$4.42	$5.01
2.5% Cap	$0.19	$0.35	$0.52	$0.68	$0.85	$1.02	$1.17	$1.33	$1.49	$1.65
5% Cap	$0.38	$0.70	$1.03	$1.36	$1.70	$2.03	$2.34	$2.65	$2.97	$3.29
$22.5 Million/Year	$0.28	$0.56	$0.80	$0.98	$1.15	$1.28	$1.36	$1.40	$1.29	$1.13
$30 Million/Year	$0.37	$0.74	$1.07	$1.31	$1.53	$1.71	$1.81	$1.87	$1.72	$1.51
$35 Million/Year	$0.43	$0.87	$1.25	$1.53	$1.78	$2.00	$2.11	$2.18	$2.00	$1.76

[16] Monthly cost calculation is solely for Residential customers.

[17] Average residential consumption was expected to drop by 0.8% each year.

TABLE 29: Average Residential Annual Bill Impact ($/Year) by Year

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Business as Usual	$6.36	$11.64	$17.16	$22.68	$28.56	$34.44	$40.32	$46.44	$53.04	$60.12
2.5% Cap	$2.28	$4.20	$6.24	$8.16	$10.20	$12.24	$14.04	$15.96	$17.88	$19.80
5% Cap	$4.56	$8.40	$12.36	$16.32	$20.40	$24.36	$28.08	$31.80	$35.64	$39.48
$22.5 Million/Year	$3.36	$6.72	$9.60	$11.76	$13.80	$15.36	$16.32	$16.80	$15.48	$13.56
$30 Million/Year	$4.44	$8.88	$12.84	$15.72	$18.36	$20.52	$21.72	$22.44	$20.64	$18.12
$35 Million/Year	$5.16	$10.44	$15.00	$18.36	$21.36	$24.00	$25.32	$26.16	$24.00	$21.12