

The Economics of Distributed Energy Resources

David Littell, Jessica Shipley, Wang Xuan, Camille Kadoch, John Brautigam, Carl Linvill
and John Shenot

Table of Contents

Executive Summary	4
Introduction	6
Why Energy Efficiency Valuation Is Easy by Comparison.....	6
Economics of Short-Run and Long-Run Marginal Costs	7
DER Values	8
Fit into Least-Cost Planning	9
Flexibility Value	9
Reliability Value	9
Resilience Value.....	10
Traditional Cost-Effectiveness Tests and Customer Value	10
Traditional Cost-Effectiveness Tests and Utility Value	13
Traditional Cost-Effectiveness Tests and Societal/Public Value and Cost.....	15
Approach to DER Valuation: Stacking	16
Values and Costs Akin to Grid-Scale Generation.....	18
1. Production energy value	18
2. Production capacity.....	19
3. Production environmental compliance value/avoided costs (current and future requirements).....	19
4. Reduced reserves and ancillary service costs.....	19
5. Reduced risk	19
6. Reduced RE obligation or RPS cost	20

7. Demand-response-induced price effect.....	20
8. Reduced O&M	20
Values and Costs Akin to Traditional Bulk Transmission and to Distribution	
Plant.....	21
1. Avoided transmission capacity costs.....	21
2. Avoided transmission line losses	21
3. Enhanced bulk system reliability.....	22
4. Reduced transmission O&M.....	22
Avoided Distribution System Capacity Costs.....	22
1. Avoided distribution line losses	23
2. Reduced or increased credit and collection costs and avoidance of uncollectible bills for utilities	23
3. Reduced distribution O&M.....	23
4. Enhanced distribution reliability.....	23
Customer/Premises Value	24
1. Customer choice and control.....	24
2. Reduced energy usage of grid electricity.....	24
3. Reduced energy usage from other fuels (fuel oil, gas, propane, wood)	24
4. Reduced bills	25
5. Reduced overall energy usage	25
6. Employee productivity	25
7. Resilience benefits.....	25
8. Property values.....	26
9. Customer comfort.....	26
Societal/Public Value	26
1. Health impacts and air quality improvements	26
2. Resilient infrastructure.....	26
3. Benefits for low-income customers.....	27
4. Water quality and aquatic species improvement.....	27
5. Employment and local economic impacts	27
Potential to Combine DERs for Synergistic Value	28
Reforming IRP to Support Synergistic DER Portfolios	30
Conclusion.....	31
Appendices Applying DER Valuation to Specific Technologies.....	33
Appendix A: Demand Response	33
1. Background	33
2. Value stacking	38
Appendix B: Value of Solar	48
1. Background	48
2. Value stacking for solar distributed generation (PVDG).....	48
3. Recent value of solar studies	57
4. Meta analyses on solar value.....	74
Appendix C: Distributed Battery Storage	81
1. Background	81
2. Value stack discussion of storage	95

Appendix D: Combined Heat and Power.....	99
1. Background	99
2. CHP and value to the customer and the grid	102
3. Value stacking of benefits for CHP	102
Appendix E: Fuel Cell Power Generation.....	117
1. Background	117
2. Studies on the value of fuel cells	120
3. Additional factors for qualitative valuation	131
Appendix F: Value Stack for DERs Overview.....	133

Executive Summary

Energy regulators and public utility commissions in the United States and worldwide are struggling to find frameworks and valuation methodologies for advanced DERs as they are being deployed and increasingly available to residential customers, businesses and utilities. This is occurring now for a number of reasons. Foremost is that the economics of specific types and classes of DERs are improving dramatically. The capabilities of a modernized grid to use granular information from many distributed (decentralized) data points is also a critical part of this transformation but is not the focus of this paper. DERs are being deployed at an accelerating rate — and these advanced DERs are outpacing the abilities of traditional regulatory mechanisms to determine their value for the grid, for customers and for the public as a whole.

There is increasing customer desire to take advantage of the ability that DERs give them to control their own energy usage and even produce their own energy. Individual customers can achieve superior energy value, pricing, reliability and resilience from controlling some or all of their own energy usage with DERs.

Another major driver is an increased recognition that DERs can provide significant grid benefits beyond the customer value. These benefits include reduced generation capacity expense, peak management and reduction, reduced distribution system stress and costs and even reduced bulk transmission system costs. Some DERs produce cleaner forms of electricity, and others, such as diesel generators, may be dirtier than conventional generation sources.

Recent technological and engineering advances allow DERs to produce many benefits among a long and impressive list of values. In application, the realization of these values will depend almost entirely on the uses of the DER, the signal or control or pricing mechanisms and how the grid operators design and operate their systems to take advantage of these new capacities. It is difficult for utilities (and regulators) to keep track of the variety of DERs, their capabilities and their applications. The technological possibilities are advancing far more quickly than a traditional utility planning cycle and capital plant investment schedules.

Against this backdrop, energy regulators and commissions are asking for information on the economics of DERs or methodologies or inputs that can be used in assessing DERs. This often arises in the context of a utility planning docket or in cost tests (the participant cost test, the societal cost test, the total resource cost test, etc.). Many regulators and commissions pose this request because these benefit-cost tests have been developed in the context of one specific DER — energy efficiency (EE). The question is important because utility regulators have sophisticated sets of practices, rules and laws built around determining the value of EE investments. And regulators naturally are seeking to transfer that experience and regulatory expertise to new types of DERs with different capabilities and value potential.

New DERs are disrupting basic assumptions around resource adequacy and the practices utility planners and regulators have developed over more than a century. Valuing new DERs using traditional EE methods can be a challenge.

That said, almost every utility commission and regulator in the United States has distribution

planning approaches and models or cost tests related to energy efficiency, some of which are quite advanced versions of these tests. Because these approaches, models and tests are developed for EE, they evaluate a set of passive demand-side reduction technologies. In contrast, new advanced end-user technologies have a broader range of operational modes that do not undermine the fundamental rationale for cost-effectiveness testing but present analytic challenges to applying current tests and approaches. For example, advanced smart hot water heaters can be ramped down to behave like EE (reducing demand), but they can also absorb excess load and provide ancillary services (and value) when controlled by the system operator. Many advanced DERs can actively increase or decrease demand, capabilities that provide support to the distribution grid. Some of these same DERs, including battery technologies, rooftop solar photovoltaic (PV) and combined heat and power (CHP), act as distributed generation (DG) and can actively increase or decrease generation onto the grid. Electric batteries can function like EE, DG or even a distribution or transmission resource — in addition to providing significant customer value.

The value of each DER depends on its specific capabilities and how those capabilities are deployed, integrated and operated as a customer and grid resource. The “use cases,” as they are sometimes called, illustrate how a specific resource will be used to realize a set of specific values. Some uses, and the associated values, need to be effectuated by grid operators. Maximizing one use may minimize the potential value from another use; deployment to specific sets of uses impacts the “value” of an advanced DER tremendously.

This paper will examine the potential uses and values of certain advanced DERs. We have acknowledged the dilemma for advanced DER valuation: with a broad range of possible use cases for specific resources, how can a specific set of quantifiable values be determined? One approach is to settle on a range of values for each use depending on resource-specific capabilities, technology deployment, operational utilization for customer and grid value and grid and use determinants. Accordingly, when studies have determined ranges, we present those in this report.

For some applications of DER, latent value is very high but also dependent on new operational deployments, procedures and integration into grid operations. In these cases, there is significant potential value beyond what conventional approaches would realize. Realizing that potential requires cooperation and diligent attention to grid investment, grid integration, operational processes and customer use. This may require new operational procedures and market rules. It will also require new utility operational capabilities and innovative approaches to do business between utilities and their customers.

Some continue to deny that DERs have any grid value or assert (often without any analysis or substantiating evidence) that grid-scale resources always provide equal or greater value at lower cost than distributed resources. As valuation frameworks shift, those who see their economic advantage slipping may attempt to impose new barriers on DER technologies or resist efforts to remove outmoded obstacles. But interfering with deployment of these technologies will raise costs for customers using them and for all ratepayers. It will also reduce customer benefits and diminish economic growth in the long term.

This paper suggests new valuation and benefit-cost approaches that may benefit regulators and

market participants. These suggestions are based upon a survey of studies and marketplace DER procurement results, located in detailed appendices, that shine a light on how DER resource valuation or costs have been determined to date. We don't, however, provide an exhaustive treatment of what, if anything, needs to change about traditional regulatory models in light of advanced energy technologies now and imminently available for customer, utility and energy service company services. Using existing distribution planning approaches, models and cost-effectiveness tests to place a value on DERs can be compared to using the cost of landline service to project the value of a mobile phone. But it is a place to start.

Introduction

Advanced DERs are being deployed globally and increasingly available to residential customers, businesses and utilities. This phenomenon is happening for a number of reasons, including the fact that the economics of specific types and classes of DERs have improved dramatically. DERs are being deployed at an accelerating rate — and these advanced DERs are outpacing the abilities of traditional regulatory mechanisms to determine their value for the grid, for customers and for the public as a whole. Consequently, regulators are struggling to find frameworks and valuation methodologies for DERs. This paper suggests new valuation and benefit-cost approaches that may benefit regulators and market participants. This new valuation is based upon detailed appendices providing a survey of studies and marketplace DER procurement results that shine a light on how DER resource valuation or costs have been determined to date.

Why Energy Efficiency Valuation Is Easy by Comparison

The broad category of EE sweeps in a diverse set of applications and technologies ranging from home weatherization (insulation and air sealing) to replacing inefficient motors and pumps at industrial facilities, to efficient lighting upgrades. All forms of EE reduce demand for a specific output of heat, power or light. Traditional EE measures do not provide ancillary services. Many DERs can. Traditional EE measures virtually never add to utility system costs, other than EE program administration costs. Many DERs can potentially add to system costs. Both of these considerations make it easier to evaluate the net benefits of traditional EE measures than other DERs.

Approaches to energy efficiency — including potential studies and application of benefit-cost tests — are covered in other RAP publications.¹ The DERs examined in this report differ from traditional EE (passive EE²) in that their value is realized both in how they are operated and how actions of the grid operator contribute to their value. Traditional integrated resource planning (IRP) focuses on energy and capacity and less so the evolving flexibility needs of operators. IRP typically provides

¹ Lazar, J., and Colburn, K. (2013, September 9). *Recognizing the full value of energy efficiency*. Montpelier, VT: RAP. Retrieved from: https://www.raponline.org/knowledge-center/recognizing-the-full-value-of-energy-efficiency/?sf_action=get_data&sf_data=results&sf_s=LAYER+CAKE+

² EE is evolving and in some applications is becoming more active, as utility systems become capable of recognizing location specific benefits. Active EE garners some new sources of value that complicate traditional EE valuation. Contrasting DERs to "passive EE", for the purposes of this paper, we consider active EE as another category of DER that poses the same valuation challenges because active EE can act as demand response and has other capacities beyond traditional passive EE.

information about variability of output (operational variability) by making reasonable assumptions about how a resource behaves and plugging those assumptions into established models. But traditional IRP overlooks some of the values associated with DERs – particularly locational and temporal values that vary at different grid locations and different times of day and seasonally. Thus, any approach to valuation must reflect dynamic responses of the grid operator, which could potentially increase value of the resource.

The needs of the grid are fundamentally changing making traditional IRP obsolete. DERs are among the resources that can meet these emerging needs like flexibility (shape, shift, shed, shimmy).

When traditional IRP processes ignore the needs, no value is placed on meeting needs, so DER capabilities remain latent and uncompensated. Active EE and DERs can provide values that have been ignored or oversimplified heretofore. Passive EE valuation was easy by comparison because it did not consider the locational and temporal needs of these emerging systems on a granular level or that DERs could be active in meeting those needs. An optimal valuation approach will include both elements from well-established IRP methods and new approaches. We hope to provide some guidance on how current planning and tests work for various DERs.

Economics of Short-Run and Long-Run Marginal Costs

A common error in valuing resources is to equate the value of DERs with the short-run real-time energy price that clears in wholesale markets. DERs provide capabilities that defer or even obviate the need for certain long-term utility investments, and compensating DERs at the short-run marginal cost alone ignores this. Fair competition between resources located on the distribution system (behind and in front of the meter) and resources operated on the wholesale electric system requires price signals that reflect long-run marginal costs for generation, transmission and distribution capacity.

If the electric services markets were in long-run equilibrium, the price signal reflecting short-term marginal costs would be economically efficient, so valuing the DER at that short-term marginal cost would be adequate. That is because when markets are in long-run equilibrium, short-run marginal cost (the cost of generating one more unit with the capacity we have) is equal to long-run marginal cost (the cost of generating one more unit with a newly constructed unit), and this is also equal to the price. However, the electric industry is rarely in a state of long-run equilibrium. Aside from the declining cost nature of some segments of electric service, the electric industry is undergoing fundamental structural change.

An aspect of the structural change underway today is that distribution service has joined generation service as a contestable market. Distribution service in the 20th century was a natural monopoly. Today, combinations of DERs can meet certain distribution service needs, making incremental distribution wires investments unnecessary where there are no barriers to competition. System needs can be better met by customer and third-party investment, so ensuring a level playing field is paramount. If customers with on-site generation, smart inverters, storage or flexible loads can provide system services, they should be encouraged to do so when and where it is

cost-effective. Customer investment can affect both bulk power system needs (generation and transmission) and local distribution infrastructure needs.

Rate tariffs that are not designed to adequately reflect long-run marginal costs can therefore distort consumer valuation of the DER. Rates above the long-run marginal cost of the transmission and distribution (T&D) supply and other costs might lead consumers to overinvest in DERs. Rate tariffs set above the marginal costs of DERs may encourage utilities to invest in capital plant that is uneconomical.

As real-time information systems that capture time- and place-specific data take hold on the distribution system, it is essential to have prices that convey the value of avoiding T&D grid investments. Determining value in the transition to an incipient 21st-century grid is an inexact science as information systems and markets for distribution services are still maturing. However, we can say that limiting price signals to short-run costs will cause overinvestment in large-scale wires solutions, underinvestment in distributed energy systems and local solutions and higher rates for all utility customers.

DER Values

DERs can perform a wide range of traditional power system functions in addition to supplying power. DERs can support transmission and distribution assets, while also providing tremendous customer value. Distributed generation is currently a supplement to central station generation, though it could eventually surpass it in terms of total output. It is conceivable that DG may satisfy a large portion of grid energy with behind the meter (BTM) generation in a grid of the future, particularly when paired with complementary DERs in microgrid configurations.

DERs can also function as transmission or distribution resources. A DER can effectively add capacity to the bulk transmission system and/or to the distribution grid. Batteries can be deployed at bulk transmission substations or at distribution substations to provide energy balancing, voltage and reactive power support and even frequency regulation. Non-wire alternative (NWA) projects have been implemented in a number of jurisdictions to fulfill a distribution or transmission function by reducing peak loads with a portfolio of DERs at advantageous locations on the grid. And inverter-based DERs can use the capabilities of new UL-1741 compliant inverters to provide local voltage support to protect against under- and overvoltage situations on the local distribution grid without the need for capacitors. Capacitors, of course, add system cost and reduce grid efficiency, so both grid cost reductions and efficiency improvements are possible on a grid with UL-1741 compliant inverters.

Because advanced DERs have value realized both in how they are operated and how they are deployed by the grid operator, thoughtful integration and establishing new operator procedures and training are critical to realizing some of these values. For example, batteries offer significant value through their distribution system support function because they help balance local circuit loads and provide voltage support. But the value to the distribution grid may not be realized for batteries operated for another purpose, such as to hedge energy prices or to fulfill contractual obligations to maintain a high-level of charge on a circuit.

Fit into Least-Cost Planning

In theory, DERs can readily fit into least-cost planning. In reality, the traditional tools of least-cost planning (e.g., distribution planning and IRP) assume that DERs are passive. These planning processes have their roots in days when utilities were vertically integrated, electricity need was boiled down to the need for energy and peak capacity and all electricity needs were met with utility-owned plants with well understood capabilities and costs. Although EE resources might adjust the energy required and DR resources might help shave peak needs, DERs as a whole were treated as *ex ante* adjustments to need rather than as active resources that could help meet dynamic system needs. In virtually all planning exercises, the *ex ante* approach assumes specific amounts of EE and DR, which means the amount of EE and DR to be procured to minimize cost is never modeled or calculated. In this simple world, production cost models were used to calculate costs of electricity supply, and T&D modeling together with operational data and experience of utility engineers were used to assess the need for a new T&D plant. None of these tools were designed for, nor can they easily incorporate, generation, storage or provision of service at the distributed end of the grid. So new approaches are being closely examined, assessed and incorporated, sometimes with controversy.

Flexibility Value

DERs have location specific capabilities that grid scale resources do not. Those capabilities can add flexibility to the grid. Batteries can be utilized at substations to ensure that substation loading is not exceeded thus extending the life of existing substation equipment. They can also store power from local DER generation flowing backward toward the substation to be available at other times when demand on that substation is high. DERs also have flexibility attributes that are not location specific, such as the ability to shift and shape loads. This flexibility can open up new potential to operate in ways heretofore not functionally available. It can also provide value that traditional distribution engineers have not been trained to incorporate into their systems.

In addition, DERs have many of the flexibility attributes that grid scale resources provide. Inverter-based DERs in particular can provide real-time ancillary services and can respond to the flexibility needs of the bulk system when loads need to be shifted or shaped to match system needs.

Reliability Value

All of the flexibility capabilities protect grid reliability enhance and protect the reliability of the grid. That said, the ability of DERs to enhance the reliability of the grid is only now being explored and understood through utility and third-party pilots. DERs can enhance grid operator abilities to manage peak through load shifting, load reductions or very short-term actions to maintain voltage and frequency within acceptable power quality tolerances. The flexibility values discussed above all enhance grid reliability.

Of course, poorly managed DERs can hinder reliability. So a substantial part of the inquiry is looking into the right mechanisms to provide operator visibility or control and standards to ensure reliability and service quality. For example, automatic set -points to maintain voltage and frequency can provide reliability benefits such as those described in the revised 2018 IEEE 1547 Standard for

Interconnection and Interoperability of DERs. These smart inverters can correct reliability issues caused by the DERs and provide additional ancillary services such as voltage support.

Resilience Value

Resilience value is not universally defined and is a current subject of debate on how it should be defined. According to some definitions, resiliency is “the ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions.” DERs can provide islanding capability (the ability to separate from the grid in the event of a grid failure), allowing specific distribution circuits to ride through a blackout. During an outage, some DERs provide substantial resilience value.³ As noted, batteries or combined heat and power (CHP) can safely island a facility or a circuit for a time period during a grid outage. DG and/or CHP combined with batteries can island a facility or circuit(s) in the form of a microgrid for quite some time. But IRPs generally attach no value to resilience. Resources that can serve critical local loads and needs during grid outages are not given any “credit” for that capability. This contributes to a systematic undervaluing of microgrids. This is especially true for DERs that enable critical facilities (e.g., military bases, police and fire stations, hospitals and cell towers) to continue providing public services during power outages.

Resilience of critical facilities protects public health and safety, at large, so belongs in an IRP as a value. Resilience that provides private benefit to a company, such as allowing them to operate through outages, provides private benefit to that company but not necessarily public benefit. So microgrids sometimes provide public benefit, sometimes private benefit and sometimes a combination of both.

We observe that the resilience value of DERs is either societal or a participant value rather than a utility value. Most IRP and integrated distribution plan (IDP) decisions are made on the basis of minimizing utility costs. DER programs, on the other hand, are often approved or rejected based on the total resource cost test of the societal cost test.

Traditional Cost-Effectiveness Tests and Customer Value

Starting with energy efficiency programs, regulators, efficiency administrators and experts have refined what are now six approaches to evaluating the costs and benefits of grid resources. These tests each measure value from a different perspective.

The seminal reference document for cost-effectiveness (C-E) testing in the electric power sector is California’s *Standard Practice Manual for Economic Analysis of Demand-Side Programs and Projects* (CaSPM). The CaSPM was originally published by the California Public Utilities Commission (CPUC) in 1983, but it has been updated in the years since.

The CaSPM defines four ways to test cost effectiveness and offers a standard methodology for conducting each test. Each test considers the C-E question from a different perspective and identifies categories of costs and benefits that should be included in the test. The four tests

³ Pacific Northwest National Laboratory, Energy security/resiliency, citing E.O. 13653. Retrieved from: https://www.energy.gov/sites/prod/files/2016/09/f33/campus_energy_security.pdf

described in the CaSPM are the participant test (PT), ratepayer impact measure (RIM), program administrator cost test (PAC) and total resource cost test (TRC). A fifth test, the societal cost test (SCT), is described in the CaSPM as a variant of the TRC but is treated by practitioners in many other states as an entirely separate test. In 2017, a group of EE professionals from multiple organizations collaborated to produce a *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources* (NSPM) that builds on the CaSPM.⁴ The NSPM suggests yet another C-E test, the resource value test (RVT). The long-established C-E tests and the new RVT are summarized in Table 1.

Table 1. Cost-Effectiveness Tests

Test Name	Question Answered	Summary of Approach
Participant Test (PT)	Will costs decrease for the person or business by adoption of a DER or set of DERs?	Considers the costs and benefits experienced by the customer
Ratepayer Impact Measure (RIM)	Will utility rates decrease?	Considers the costs and benefits that affect utility rates, including program administrator costs and benefits and utility lost revenues
Program Administrator Cost Test (PAC)	Will the utility's total costs decrease?	Considers the costs and benefits experienced by the utility or program administrator
Total Resource Cost Test (TRC)	Will the sum of the utility's total costs and the participant's total costs (or energy-related costs) decrease?	Considers the costs and benefits experienced by all utility customers
Resource Value Test (RVT)	Will utility system costs be reduced, while achieving applicable policy goals?	Considers utility system costs and benefits, plus those costs and benefits associated with achieving energy policy goals
Societal Cost Test (SCT)	Will net costs to society decrease?	Considers all costs and benefits experienced by all members of society

The categories of costs and the value streams (i.e., benefits) included in the calculations vary from state to state and often across the different types of DERs, even while using the same name to describe the test.

⁴ Retrieved from: <https://nationalefficiencyscreening.org/national-standard-practice-manual/>

Looking more closely at the first two tests, the PT is often based on a benefit-cost ratio⁵ representing the value to the participant of participating in an energy efficiency or other DER program. The RIM test represents a benefit-cost ratio representing the impact of an energy efficiency or DER program on electricity rates when the sources of benefits and costs are narrowly defined. The RIM test does not represent the nonparticipant perspective because it does not include the nonenergy benefits that accrue to members of the general public, such as public health benefits, environmental benefits and economic development benefits.⁶ The net bill savings to the participant depend on the rate design and tariff applicable for the host utility, and the applicable rate design and tariff can be different for different technologies. In the PT, the net value to the consumer includes the net energy and resource savings but does not encompass other potential benefits.

Customer value is approached through the PT to assess how an individual customer's costs will increase or decrease as a result of using a DER or set of DERs. This test looks at the savings, costs and benefits at the consumer level. It may be multifaceted, for example a customer with DG in the form of rooftop solar may also transition to electric space heating and water heating (e.g., air-source heat pump technologies) or add an electric vehicle (EV). Individual customer DER adoption can involve different configurations of DERs, which may save the customer money and add to customer satisfaction in complementary ways, depending on the technology and the tariffs in place.

Some cost tests also consider whether benefits received by DER owners come at a cost to nonparticipating customers. Under a net-metering or feed-in tariff, a customer's financial benefits (i.e., bill savings, financial incentives, and payments for excess generation) are often allocated across the rate base. If the system benefits of those DERs are less than the compensation to the DER owners over a specific time period, the DER can have measurable impacts on electric utilities and nonparticipating customers. This assessment must be done over a long time horizon. Seldom does any new utility investment yield benefits in year one to justify the costs to ratepayers in that year, as benefits are often spread over the operational lifetime of any utility plant or DER investments. Adaptation by the utility also matters. For new technologies, benefit and cost flows may differ in the short and long run as utilities gain experience with operating and integrating higher penetrations of varied DERs into their systems.

The interests of nonparticipating customers can be defined narrowly, based on how the reduction in sales to adopting customers affects the rates that all customers pay. The RIM test attempts to capture this perspective. When retail customers conserve energy, invest in energy efficiency or install self-generation of any type, those customers' contributions to utility revenue may decline. On the other hand, some DERs may increase net customer contributions to utility revenue. The installation of DG that serves retail load directly, under any form of net energy metering (NEM), will be a concern to nonparticipants if they perceive that system-wide economic benefits are insufficient to offset the utility's loss of revenue.

⁵ The PT does not need to be expressed as a ratio. It can be expressed as a net benefit. An EE measure with a 1.1:1 B/C ratio might generate \$1,100,000 in benefits for \$1,000,000 in costs – a net benefit of \$100,000. Another measure with a 3.0:1 B/C ratio might generate \$30,000 in benefits for \$10,000 in costs – a net benefit of \$20,000. While a high B/C ratios is desirable, achieving net benefits that are higher is more desirable.

Most applications of the RIM test fail to capture the full long-run marginal cost impact of customer-sited DG. To fairly value a DER installation, it is important to include all of the long-term utility system benefits arising from avoiding transmission, distribution and generation investment as well as avoided portfolio standard compliance costs, reduced line losses and other benefits. Including all long-term benefits and costs is an important first step for accurately addressing whether there is, in fact, a cross-subsidy of participants by nonparticipants.

Another factor is that DER produces intangible benefits for many nonparticipants. It is reasonable to assume that DER participants are only a fraction of those citizens who support clean energy goals. Polling consistently puts support for clean energy well above 50% nationally.⁷ The true value of DER to typical nonparticipants may be more accurately represented by a TRC or SCT perspective. Those who support clean energy goals are likely to place a value on the nonenergy benefits of an installation, and thus an SCT score may be a reasonable proxy for these nonparticipants. From a third perspective, nonparticipant benefits should also include a list of nonenergy benefits that accrue to the population residing within the service territory of the utility.⁸ Economic development benefits (stimulation of the local economy and job growth), environmental benefits and health benefits are enjoyed by nonparticipants and participants alike and arguably must be included along with the traditional RIM components in assessing the nonparticipant's net value proposition.

Traditional Cost-Effectiveness Tests and Utility Value

The utility cost test (UCT), also referred to as the program administrator cost (PAC) test,⁹ represents a benefit-cost ratio from the utility perspective where the utility or a third-party entity is an administrator of an EE or DER program.

DERs that serve retail load directly have created concerns for utilities. In many states the customer receives credit at the full retail rate for power the customer provides to the utility. But the full retail rate does not account for distribution costs. Utilities often suggest that these costs should be compensated and that ignoring those costs results in a subsidy from nonparticipating customers to those who install DERs. When purchases from the grid decrease, the utility sees not only a reduction in revenue from energy charges but also from distribution and transmission charges. This revenue impact is affected by tariff terms, rate design and the presence or absence of decoupling. Decoupling can be designed to offset revenue losses from DERs.

On the other hand, there are distribution and even transmission system benefits from installation of DERs: avoided energy, capacity and ancillary service costs; avoided transmission; net avoided

⁷ For example, three-quarter of votes want to see more solar, 70 percent want more wind, 61 percent want more hydro and 51 percent want less coal. S. Lacey, (2016, Dec.). New Survey Shows That Renewable Energy Polls Extremely Well Among Trump Voters. GreenTechMedia (GTM). Retrieved from: <https://www.greentechmedia.com/articles/read/new-survey-shows-renewable-energy-polls-ridiculously-well-among-trump-voter#gs.8laqcy>

⁸ Keyes, J. B., and Rábago, K. R. (2013, October). *A regulator's guidebook: Calculating the benefits and costs of distributed solar generation*. New York: Interstate Renewable Energy Council (IREC). Retrieved from: <https://www.growsolar.org/wp-content/uploads/2014/10/A-Regulators-Guidebook-Calculating-the-Benefits-and-Costs-of-Distributed-Solar-Generation.pdf>

⁹ The terms "utility cost test" and "program administrator test" may be used interchangeably.

distribution; and avoided costs associated with reductions in line losses, reserves, uncollected bills and service terminations. Also, as noted above, some DER technologies increase the net kWh purchased from the grid, resulting in a revenue benefit to the utility.

The value of DG to the electric system varies by technology, location and time. Because the value of DG is technology and location specific, the avoided cost value to the utility will likewise be technology and location specific. And thus, any credible test must take into consideration location, technology and other factors beyond the raw number of kWh generated.

Another consideration is properly allocating administrative and metering costs utilities must incur to enter into contracts with NEM and feed-in tariff (FIT) generators. Increased costs could include initial capital to procure advanced metering, increased operations and maintenance (O&M) expenses to provide for the metering and elevated invoicing and payment processing costs to accommodate payments or credits to the customer. Where metering infrastructure provides visibility or even some amount of control to the system operator, there is an operational benefit to grid operations and possibly to nonparticipating customers. Some utilities such as Green Mountain Power have used their control over batteries to hedge in the energy markets, shifting purchases from high-price periods to lower-priced periods and saving their customers hundreds of thousands of dollars in a single day.

When considering the impact of DG on utility resources, the owner of DG may appear to have three different relationships with his or her utility. First, during times when the distributed system is not generating electricity, the customer's load will look just like that of any other customer. Second, when the system is generating electricity equal to or less than the customer's on-site consumption, the customers will have reduced load, similar to what might happen if he or she had deployed energy efficiency measures. Third, when the customer generates more power than he or she consumes, the customer becomes an exporter of electricity to the system.

Three considerations determine whether negative earnings impact utility shareholders triggering predictable utility reluctance to integrate cost-effective DERs. First, the utility may lose revenue as a result of the on-site consumption of DER output behind the meter. To the extent that there is displaced retail revenue exceeding short-term cost savings during the time and location of DER operation, there will be an adverse impact on earnings. Second, with FITs and some NEM tariffs for utilities providing electricity supply to customers, the utility incurs a cost in purchasing the power exported to the grid that may exceed the short-run hourly cost of conventional power. Both of these can have an impact on utility shareholders (until rates are adjusted to reflect changes in sales) and on nonparticipating customers (in the long run). Third, the utility can experience a net decrease in investment opportunity if the loss of investment in distribution, transmission and/or generating resources exceeds any incremental investment opportunity created by increasing DERs.¹⁰ But revenue opportunities could also increase. There are examples of increased utility investment opportunity, including incremental investment in the distribution system to enable net backflow of electricity to the grid, and shared investment opportunities in which the utility participates in

¹⁰ This latter category of impact can also be viewed neutrally or even positively if there is regulatory lag (in rate recovery) and/or the utility's marginal return is at or below a normal average return.

leasing DER equipment or invests in a portion of the control equipment (such as smart inverters, solid state transformers or enhanced two-way metering equipment). The potential that higher levels of DER, including solar PV penetration, may cause additional utility investment to maintain system reliability is beyond this paper's scope.

Traditional Cost-Effectiveness Tests and Societal/Public Value and Cost

The total resource cost (TRC) test and the societal cost test (SCT) represent a benefit-cost ratio for the public as a whole. The TRC typically excludes most or all nonenergy benefits, and the SCT typically includes nonenergy benefits.¹¹ The newer RVT includes nonenergy benefits that contribute to the achievement of established public policy goals of the jurisdiction in question but excludes other nonenergy benefits.

Higher penetration of DERs produces benefits for the public as a whole. The TRC test evaluates those energy-related benefits and costs that can be readily quantified with expressed economic values. The SCT includes all of the quantified benefits and costs from the TRC but adds nonenergy externalities that are benefits or costs from a societal perspective but are not easily expressed in economic values under the methodologies utilized. The RVT adds a subset of societal benefits to a UCT. Those who value all of the resource benefits as well as the nonenergy benefits of DER programs are likely to value the programs from a TRC, RVT or SCT perspective whether they are participants or nonparticipants.

Although nonenergy benefits are often neglected or downplayed, nonenergy benefits are actually driving the demand for DERs in some cases. For example, the environmental benefits of avoiding building infrastructure or generation in an urban area can drive consideration of NWAs that happen to be constituted primarily of aggregated DERs. And environmental benefits are not the only nonenergy benefit driving DER projects today. For example, local resiliency projects anchored by a microgrid powered with DERs are increasingly being selected to ensure reliable operations in exigent circumstances. Cyber and national security is another nonenergy benefit to which DERs may contribute. And of course climate impacts from reduced emissions can be quantified and factored in. Interest in grid resiliency and security has already spurred investment in a range of DER including storage, renewable and CHP DG technologies.

The TRC, RVT and SCT tests are useful in guiding the level of DER penetration that will be consistent with the public interest. Tariff design attributes (e.g., the level of any fixed or variable charge, the periodicity of netting if the tariff is a NEM tariff) are also relevant to the TRC, RVT or SCT, insofar as those choices can target efficient and beneficial levels of DER penetration.

¹¹ Initiatives to advance methods and definitions are underway for energy efficiency such as the National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, Ed. 1, Spring 2017 published by the National Efficiency Screening Project (NESP) which sets forth the RVT discussed in this paper and an initiative by NESP to examine a National Standard Practice Manual for Benefit-Cost Analysis of DERs.

Approach to DER Valuation: Stacking

The approach to DER value streams that we put forth in this paper is a stacking approach. We identify values and costs that can be effectuated and then create stacks, allowing them to be assessed together to estimate the full valuation and costs for any set of uses or installations. Table 2 illustrates these value streams and what traditional power system function the DER complements, supplements or supplants.

Table 2. Illustrative List of DER Value Streams

Traditional Resource Function	DER Value Streams
Generation	Production energy value
	Production capacity
	Production environmental compliance value/avoided costs
	Reduced reserves and ancillary service costs
	Reduced risk
	Reduced RE obligation or RPS cost
	Demand-response-induced price effect
	Reduced O&M
Transmission and Distribution	Avoided transmission capacity costs
	Avoided line losses
	Enhanced bulk system reliability
	Reduced transmission O&M
	Avoided distribution system capacity costs
	Avoided distribution line losses

	Reduced or increased credit and collection costs and avoidance of uncollectible bills for utilities
	Reduced distribution O&M
	Enhanced distribution reliability
Customer	Customer choice and control
	Reduced energy usage of grid electricity
	Reduced energy usage from other fuels (fuel oil, gas, propane, wood)
	Reduced bills
	Reduced overall energy usage
	Employee productivity
	Resilience benefits
	Property values
	Customer comfort
Societal	Health impacts and air quality improvements
	Resilient infrastructure
	Benefits for low-income customers
	Water quality and aquatic species improvement
	Employment and local economic impacts

For any specific use or deployment, the value streams above that apply can be quantified based on the best data available from studies, markets or even utility RFPs. That said, quantifying the economic value of each value stream can be difficult, inexact, and controversial. Quantitative values can be based on economic studies, market prices or an administrative determination made by utilities or regulators. The stack of “values” may include negative numbers (costs) as well as positive numbers. And some value stack components are interdependent, and the total value of a resource is not simple addition. For example, DERs committed to providing local voltage regulation (to avoid

a substation upgrade) are not also available to provide bulk system frequency response.

Market-based values work best when market rules are broadly designed to procure DERs on a nondiscriminatory basis on a level playing field with other resources. Many regions have competitive wholesale markets for electric energy, generating capacity and some ancillary services. Competitive markets also exist in some jurisdictions for greenhouse gas (GHG) and criteria air pollutant emissions allowances and renewable energy certificates. Establishing a wholesale electricity market does not automatically reveal economic value; market rules and procedures need to be designed to define and compensate for the value of various services that DERs can provide.

Administratively determined values are typically based on traditional methods for assessing utility costs of service, but in the case of nontraditional or difficult-to-quantify value streams (e.g., reduced risk or environmental benefits), it may be necessary to use values from studies or proxy values based on professional judgment.

A final key point to emphasize is that the economic value of many value streams can be time dependent or location dependent. For example, resources and actions that only reduce demand during off-peak hours may have a value of zero with respect to avoided generation capacity costs, while actions that reduce demand by the exact same amount during peak hours might have a high value. This is because the amount of capacity utilities procure is dependent on peak demand; reducing off-peak demand does not reduce generation capacity costs. Similarly, resources and actions in one location on the distribution system might alleviate a constraint and have a high value for avoided transmission and distribution system investment, but the same resources and activities in an unconstrained part of the grid might have no such value.

Values and Costs Akin to Grid-Scale Generation

1. Production energy value

DERs generally reduce directly the amount of energy to be procured by the utility from the wholesale markets or produced by a vertically integrated utility. This directly reduces energy production costs. It also reduces overall costs of energy purchased due to a demand-price reduction effect, which is addressed in more detail in section 7 below. Behind the meter, DERs have both effects of reducing direct wholesale purchases and indirect demand-reduction effects. Of course, there are exceptions. Battery storage will increase demand when charging from the grid (but not when charging from behind the meter generation). On a system with excess intermittent generation from solar or wind, active demand capacity can be utilized to balance that production with demand efficiently, for redispatch or behind the meter use when needed when the production value is low or even negative.

In markets where the clearing price sets all the wholesale transaction prices and the demand curve is sloped, the excess energy provided by DG for export to the grid decreases all wholesale prices and thus benefits consumers and all purchasers. DG thus generally reduces the amount of energy to be procured from other generators. The demand-reducing price effect is described in more detail below.

2. Production capacity

DERs generally reduce maximum peak demand and thus the amount of capacity to be procured by the utility or from the wholesale markets. This is particularly true of solar generation in the summer when the afternoon peak is shifted into early evening. This often reduces overall system peak on summer peaking systems found in most of the United States.

3. Production environmental compliance value/avoided costs (current and future requirements)

To the extent that energy supply and production capacity is reduced, some generation environmental costs and impacts are likely avoided. Older generation can retire, avoiding the cost of air emissions and water discharge controls. Less new central station generation may be necessary for both energy supply and capacity.

4. Reduced reserves and ancillary service costs

As overall load and capacity are reduced, the need for corresponding reserves also decreases. This is true of both short-term (spinning reserves) and longer-term (30- or 60-minute) reserves.

Consumers absorb the costs of reserves. Reducing reserves directly reduces expenditures to load and consumers for maintaining reserves necessary to maintain system reliability. Aggregated DERs can also reduce reserves and provide flexible shaping and shifting of load to meet the availability of generation and lower-cost generation from time periods of under a minute to up to several hours. For ancillary services, inverter-based DERs are excellent providers of fast frequency response when configured to provide frequency response.

5. Reduced risk

DERs may potentially decrease risk on the grid, but they may also increase risk. Whether DERs increase or decrease risk is purely a function of their integration into the grid with updated grid operations, procedures and processes. Integration should take advantage of DER capabilities and interconnection, ride-through and inverter settings adopted under the revised IEEE 1547 (2018) standard. Some of those standards, processes and procedures are adopted by utilities, others by state commissions, and yet others were set at the regional or federal level. There are costs associated with each of these integration factors.

At the customer level, DERs are likely to reduce risk of loss of service depending on the type of DER and its configuration and installation. DERs capable of providing backup power can be designed with switches to automatically island in the event of a grid failure (as does a backup generator typically). Those configurations with battery backup will reduce customer outage risk.

DERs can also reduce customer risk of outage at a larger scale, such as microgrids. A number of microgrids are being designed to island with combinations of CHP generation, batteries and/or

solar, from New Jersey to California. Some are utility owned and others are privately owned. In one of the first test cases, Consolidated Edison has successfully configured a distribution circuit to be able to island and operate independently during a grid blackout. We may see more distribution circuits that function as a microgrid during a shutdown, while also serving as a fully integrated distribution circuit under normal operations. The net effect of these microgrids is to reduce the number of meters impacted by any system interruption.

6. Reduced RE obligation or RPS cost

In some states, renewable energy certificates (RECs) are credited directly to utility and service territory accounts. For those states, DERs that generate RECs can directly reduce renewable portfolio standard (RPS) costs. Even if not credited directly to utility or compliance accounts, the additional generation of RECs will increase the supply and therefore reduce the costs of RPS compliance. This is particularly the case where state RPS's establish separate tranches for specific categories such as solar RECs (SRECs), creating narrow and specific REC requirements. Even if DERs do not count toward renewable generation credits, the presence of DERs reduces the energy demand, which reduces the quantity of credits required. For example, a reduction of load reduces the need for RECs, so with a 25% RPS, fewer RECs are required than would be the case had the load reduction not occurred.

7. Demand-response-induced price effect

Demand-response induced price effect (DRIPE) is the additional reduction in wholesale energy and capacity prices beyond the simple avoided whole or production costs (discussed above). DRIPE is sometimes referred to as the price suppression effect because excess electricity supply or capacity will have an effect of reducing the prices and costs further. In a market, a lower demand will mean a lower price. For DERs that create additional electricity supply or capacity — or that reduce the demand for supply or capacity — there will be a corresponding DRIPE, reducing the overall cost of those amounts in the wholesale markets.

8. Reduced O&M

The costs of operations and maintenance on utility plant falls on all ratepayers whereas the cost of O&M for distributed resources, as well as wear and tear, usually falls upon the DER owner. To the extent those costs would fall on the ratepayer or customer through direct utility charges or indirectly through higher capacity market or energy bids, the incorporation of DERs in grid operations should reduce ratepayer expense. The DER owner will pay for O&M and wear-and-tear on that equipment — costs that will not be borne by other ratepayers. To the extent that DERs shift some wear-and-tear costs off the utility system and onto the owner of the DER, this will reduce ratepayer expense.

Values and Costs Akin to Traditional Bulk Transmission and to Distribution Plant

1. Avoided transmission capacity costs

DERs generate, store or reduce demand locally. In some cases, DERs may operate at distribution substations or even bulk power system substations. In all these cases, DERs can supplement and add flexibility in the grid beyond that created by traditional central-station power plants of the 20th century.

The additional transmission capacity that DERs provide depends not only on their location on the grid, but in large part on the specific DER and its ability to provide relief or additional capacity to the bulk transmission system. Demand-reducing DERs at customer premises will reduce the need for capacity from the grid. The capacity need displaced exceeds the DER capacity because locally generated power also avoids line losses. If the DER offers capacity at peak times the benefit is especially high because line losses are higher during peak hours.

Bulk transmission infrastructure, like many resources, has a life expectancy. Reduced wear and tear and usage can extend that life expectancy. Transmission and distribution plants are designed to operate under specific conditions: substation equipment, transmission lines, feeders and distribution lines are designed to carry current within specific parameters and can suffer from voltage or thermal overloads when current flow or voltage limits are exceeded. If short-term emergency operating limits for this infrastructure are exceeded, life expectancy will be reduced markedly. DERs that reduce the need to flow energy over this T&D plant, either through local generation or demand reductions, can directly reduce operations and maintenance costs and extend or maintain equipment life.

If a DER does not reduce peak demand, it can nonetheless reduce the need for transmission (and distribution) and provide T&D capacity value. The useful lifetime of some T&D equipment is not reduced by peak load, but its longevity is also affected by how loaded the equipment is during high-load hours. Thus, reducing load during high-demand hours can extend T&D capacity costs.

DERs that generate power at residential premises would appear to the bulk power system as system load reduction with the benefits to transmission system capacity discussed above. DERs, such as batteries, which can generate power or absorb excessive peak flows as well as provide frequency and voltage support, can more directly enhance transmission system capacity.

The need to expend additional amounts on transmission can be avoided, but the potential of DERs can only be realized if they are integrated in T&D operations with operator visibility or control. If that is not accomplished, DERs can create additional demand on the transmission system plant.

2. Avoided transmission line losses

DER that frees up transmission capacity also reduces line losses. These are illustrated for T&D under “Avoided Distribution System Capacity Costs” below.

3. Enhanced bulk system reliability

As DERs increase transmission capacity, they also enhance the ability of the bulk transmission system to handle voltage and frequency disturbances across the system. DERs can play this role regardless of where they are installed and operated — from customer premises to the distribution system to the bulk system itself, if operational rules are in place that allow aggregated DERs to offer wholesale services to the bulk system operator.

As noted above regarding bulk power system capacity, if DERs are not operationally integrated into T&D operations, their deployment could degrade bulk system reliability as well as capacity. Further, a resource committed to provide local frequency regulation may not be available to provide bulk system frequency response. So the value stack is interdependent and the full value of a resource is not simple addition.

4. Reduced transmission O&M

Bulk transmission infrastructure, like many resources, requires some regular operational maintenance and other costs. While reduced wear and tear and usage can reduce O&M, reducing wear and tear is more properly considered under reduced transmission capacity.

Avoided Distribution System Capacity Costs

Many DERs have the potential to reduce both system and local circuit and substation/feeder peak loads. Reduced peak across circuits can reduce peak-related distribution investments, which have traditionally driven distribution system investments. Peak reductions can also reduce distribution-reliability-related investments, which are often correlated with peak service levels on circuits, feeders and substations, including interconnected circuits capable of handling diverted power flows from nearby circuits during failures and maintenance.

Reducing system peak can directly reduce overall system capacity costs. DERs that reduce system demand and peak will reduce system capacity expenses. This is true of DG at low levels of penetration. At high levels of penetration, more distribution capacity can be required to integrate high levels of DERs. Those costs can be minimized by installing control equipment to stop DER flows onto the grid at certain times (as Hawaii has done). DER can also be integrated to ensure they operate at locations and times when the grid requires support.

Grid operator visibility over DER systems can allow for planning and effective integration to ensure that DER enhances distribution system capacity by operating when needed to reduce distribution grid demands. Grid operator control of DERs can further enhance distribution grid operations, reduce risks and costs to the distribution grid and enhance distribution grid capacity and reliability.

Lastly, DERs reduce usage and wear and tear on the transmission and distribution system. Over the long term, this extends the life of T&D plant and reduces operations and maintenance expense, as more fully explored above in “Values and Costs Akin to Traditional Bulk Transmission and to Distribution Plant.”

1. Avoided distribution line losses

All DERs either reduce demand or increase generation at or near the end user. Consumer generation that is consumed on premises or demand-reducing resources such as energy efficiency entirely eliminate line losses. Line losses from central station generation to end users through the bulk power system and the distribution system range from 7% to as high as 20%. So the true energy and capacity value of a DER is the avoided cost of power multiplied by a factor of 1.07 to 1.2.

Line loss factors grow as the transmission and distribution system reaches peak usage. Thus, the line loss benefits of DER are greatest when the system is under the most stress. Accordingly, as distributed resources relieve the system under peak conditions, they help avoid line losses, decrease system peaks and increase the overall ability of the modern grid to manage increased levels of dynamic energy use.

2. Reduced or increased credit and collection costs and avoidance of uncollectible bills for utilities

DERs will reduce utility credit and collection costs and uncollectible bills to the extent that DERs reduce individual customer costs. Individual customers with lower costs are less likely to incur credit or collection costs for the utility. If on the other hand, DER integration raises overall energy costs for those unable to pay increased costs, then DER integration could increase uncollectible bills and corresponding credit and collection costs.

3. Reduced distribution O&M

DERs reduce capacity needs, usage and wear and tear on the transmission and distribution system, as noted above in multiple sections. There can also be reduced operations and maintenance costs for regular distribution operations.

4. Enhanced distribution reliability

DER integration can enhance (or degrade) distribution system reliability. For example, batteries deployed at substations and customer premises with operator visibility and/or control can effectively manage substation peaks and defer or avoid expensive substation upgrades. This same ability to manage system peaks enhances the ability of the system to operate under stressed conditions, including N-1 conditions where one substation may need to handle diverted flows from another circuit failure. DERs deployed at the substation and at customer premises with operator visibility and/or control will allow the operator to more successfully manage failure situations to maintain service to some or all customers on different circuits. We note that the recent adoption of IEEE 1547 (2018) interconnection technical standard and the UL 1741 inverter standards provide

commissions, utilities and system operators with a technical standard basis to ensure inverter-based DERs enhance grid reliability.¹²

Customer/Premises Value

Whether the value streams examined above flow through to the consumer is largely a function of retail rate design and whether aggregators are permitted to operate and capture value on behalf of consumers in wholesale markets.

1. Customer choice and control

DERs are providing customers with their own choice of energy systems. Customers can choose systems that meet their specific needs and preferences. The value of providing customers with more choice is hard to measure, but it is nonetheless a significant qualitative value in a culture dedicated to individual choice.

2. Reduced energy usage of grid electricity

For some customers, reducing reliance on the grid is a value that can be met by DERs. Some customers desire to manage their own usage more closely or simply generate their own energy. Some customers value the option of generating a cleaner form of energy than the grid can provide.

3. Reduced energy usage from other fuels (fuel oil, gas, propane, wood)

Some DERs provide customer value by reducing reliance on other fuels. Grid-enabled hot water heaters, for example, can perform a grid support function of absorbing excess grid generation from solar, wind or nuclear grid-scale power plants. Grid-enabled hot water heaters can also absorb excess local solar generation much like a battery. When several electric hot water heaters are placed under grid-operator control, they can act like a large battery when needed. All of these functions can enable reduced fossil fuel reliance at the individual customer level.

Other advanced DER technologies, such as air- and ground-source heat pumps, can economically supplant or supplement heating systems, reducing the need for other fuels. Both air- and ground-source heat pumps are used for domestic and commercial space heating and water heating. These DERs typically operate at a lower cost per delivered Btu of heat and with a relatively clean emissions footprint.

¹² IEEE (2018, April 6). *IEEE 1547-2018 IEEE standard for interconnection and interoperability of DERs with associated electric power systems interfaces*. Piscataway, NJ: Institute of Electrical and Electronics Engineers (IEEE). Retrieved from: <https://standards.ieee.org/standard/1547-2018.html>

4. Reduced bills

Reduced customer bills are clearly possible, as are increased customer bills under different DER configurations and tariff structures. Customers utilizing DER-powered heating technologies for advanced space and water heating typically see overall bill reductions from fossil fuels.

5. Reduced overall energy usage

DERs have the potential to make the energy system more efficient and thus reduce overall energy usage. Battery storage, hot water heater storage and even controllable EV charging can use both grid and distributed energy when it is generated in excess of load-serving requirement.

DERs allow use of more efficient technologies, such as beneficial electrification. Electrical air- and ground-source heat pumps are highly efficient in producing heating and cooling per unit of energy inputs.¹³ This is particularly true when replacing fossil units. These advanced heating units are both efficient and less costly for consumers and reduce overall energy requirements. A similar benefit occurs when DER is used to charge electric vehicles.

With batteries, wind and nuclear can be soaked up in the middle of the night and solar in the middle of a sunny afternoon for use later as electricity or hot water thus shifting (but not reducing) usage to lower cost or cleaner generation sources. Indeed, load shifting might slightly increase usage because batteries have round-trip losses.

6. Employee productivity

DERs that enhance facility resiliency can directly enhance employee productivity by maintaining a facility in operation. They can indirectly benefit the employer by enhancing employee comfort, lighting and health. The enhanced ability to control their energy supply can also enhance production planning. Large industrial facilities with their own generation and ability to island operations during a power outage are an example of what will become increasingly possible for all consumers as DERs deploy and microgrids become more commonplace.

7. Resilience benefits

DERs operated at individual residences, premises, business or governmental buildings can add a resilience benefit heretofore only available with a backup generator. Solar plus battery storage has the ability to operate independently. Resilience can be scaled up by usage of microgrids to an entire circuit or community, as discussed more above in “Values and Costs Akin to Grid-Scale Generation.”

¹³ Shipley, J., Lazar, J., Farnsworth, D., and Kadoch, C. (2018, November 8). *Beneficial electrification of space heating*. Montpelier, VT: RAP. Retrieved from: <https://www.raponline.org/knowledge-center/beneficial-electrification-of-space-heating/>

8. Property values

DERs add value to residential and commercial property. Because DERs add flexibility to managing energy and often offer energy expense reductions, it makes sense that property values would be enhanced. In one study of DERs' property value effect, in addition to direct monetary valuation from reduced expense, a prestige factor was observed. This explains why Japan now has an industry in fake solar panels. Lawrence Berkeley National Laboratory (LBNL) found that an average array (3.6 kW) of rooftop solar enhances property values by roughly \$15,000.¹⁴

9. Customer comfort

Some DERs provide superior customer heating and cooling. Energy efficiency has long brought better envelope heat and cooling containment, but now air- and water-source heat pumps offer heating and cooling at reduced customer expense. Many heat pump customers purchased their unit for heating but are now enjoying the benefits of air conditioning from the same technology. The Emera Maine pilot of air-source heat pumps found notable satisfaction among customers who had their first experience with home cooling, even in Maine's brief summer.

Societal/Public Value

Public or societal values accrue to everyone or to large segments of the public such as low and moderate income (LMI) ratepayers as a group. DER may serve the value of allowing a community to come together to address societal problems such as climate disruption, thereby building community connections and enhancing morale.

1. Health impacts and air quality improvements

DERs are clearly contributing to better air quality and improved public health through reduced air pollution. DERs are one reason why power sector emissions are steadily declining. Because all members of the public share these benefits as a nonmarket externality, DER owners rarely receive full if any compensation for their contributions to improved air quality and public health. Most, but not all, DERs contribute to enhanced public health and air quality outcomes. Smaller fossil-fuel-based generators using diesel, oil or natural gas could be considered distributed resources and, of course, would have the opposite effect.

2. Resilient infrastructure

Society and the economy benefit from resilient infrastructure. This benefit is different than the resilience value to individual customers and businesses. If investments allow for energy systems

¹⁴ Hoen, B., Wiser, R., Adomatis, S., Jackson, T., Graff-Zivin, J., Thayer, M., and Klise, G. (2015). *Selling into the sun: Price premium analysis of a multi-state dataset of solar homes*. Berkeley, CA: Lawrence Berkeley National Laboratory. Retrieved from: <https://emp.lbl.gov/publications/selling-sun-price-premium-analysis>

to remain operational during emergency operations, there are benefits to society as a whole and to the economy. Investments in a microgrid that can stay operational during an outage benefit the customers on the premises but also society. By mitigating impacts and facilitating a rapid recovery, the microgrid can support the economy and emergency services.

3. Benefits for low-income customers

The potential of DERs to reduce low-income energy burden is still largely untapped. Low-income participants can participate in some residential DR programs and may have more generous EE program incentives. Nonetheless, this group of ratepayers will find many DERs inaccessible due to up-front investments costs.

4. Water quality and aquatic species improvement

DERs generally reduce reliance on central station thermal generation. Excepting modern closed-loop cooling systems, traditional coal, nuclear and gas power plants rely upon large quantities of surface water for once through cooling. These systems typically entrain large quantities of fish on water intake structure or grates. They also raise the temperatures of the receiving river, lake, bay or stream beyond that where native species would survive or thrive. Further, blowdown water and other power plant water may contain significant amounts of water toxins, particularly if water is used to clean air pollution control equipment that removes fly and bottom ash. By reducing the amount of cooling water used at such generation plants, DERs directly improve water quality, which in turn impacts the health and welfare of fish and other aquatic species.

5. Employment and local economic impacts

Local and state economic impacts from large-scale DER deployments are substantial. Many states estimate thousands of workers in varied DER jobs with impacts ranging from hundreds of millions to billions of dollars of economic activity. In some states, this job sector and accompanying economic activity is a significant economic growth factor. If a state is a net importer of fossil fuels or electricity, local economies are enhanced to the extent that local investments and activities replace those net capital outflows. And state, regional and national energy security is enhanced to the extent that reliance on imports from unstable regions are reduced. States that export fuels or technologies used in grid-scale generating units may experience a parallel loss of economic activity.

Potential to Combine DERs for Synergistic Value

The same technologies and techniques that are used for a demand-reducing DER can be combined with DG to create even more value than either resource exhibits independently. For example, if a customer has a flexible load such as a water heater, an ice storage air-conditioning unit or a pool pump, these loads can be programmed to take advantage of excess generation from a customer's PV

This synergistic value has already been quantified. For example, a study found a 42% median reduction in monthly demand charges for commercial customers who combined PV with storage. This exceeded the sum of PV alone (8%) and storage alone (23%).

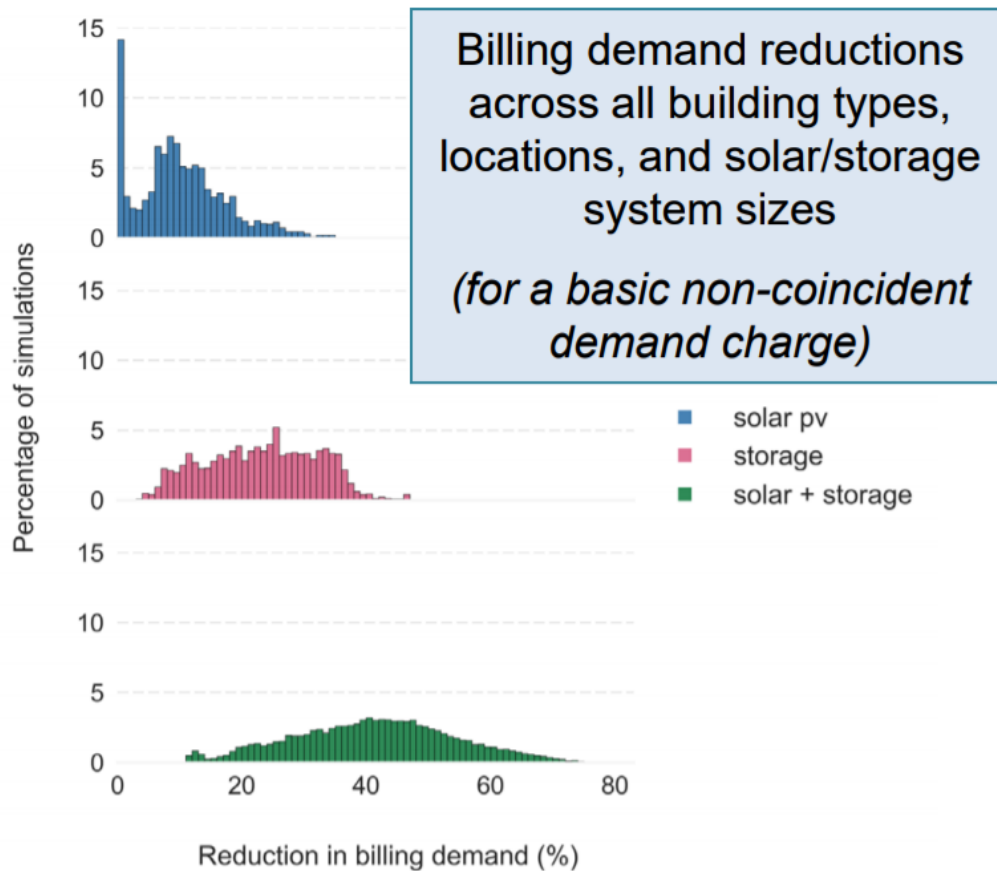
(photovoltaic) system. This can be a valuable form of DR, especially if the customer does not receive full retail rate compensation for power fed to the grid. Or, if a customer is on a demand charge rate, the combination of PV and DR might enable the customer to shift evening peak loads to daytime hours, reducing both energy and demand charges. From a utility or independent system operator (ISO) perspective, this combination of DERs can be especially valuable. Although traditional DR

programs are managed almost exclusively to shave peaks during system capacity shortages, newer forms of DR can shape, shift and shimmy¹⁵ loads to better integrate large amounts of generation from solar, wind and other variable energy resources. This creates value for all ratepayers in the form of avoided energy, capacity or ancillary service costs.

This synergistic value has already been quantified. For example, a study by LBNL and the National Renewable Energy Laboratory (NREL) found, as shown in Figure 1, a 42% median reduction in monthly demand charges for commercial customers who combined PV with storage. This exceeded the sum of PV alone (8%) and storage alone (23%).¹⁶

¹⁵ Alstone, P., et al. (2017, March). *2025 California demand response potential study: Charting California's demand response future; Final report on phase 2 results*. Berkeley, CA: Lawrence Berkeley National Laboratory. Retrieved from: <http://eta-publications.lbl.gov/sites/default/files/lbnl-2001113.pdf>

¹⁶ Gagnon, P., Govindarajan, A., Bird, L., Barbose, G., Darghouth, N. R., and Mills, A. D. (2017, October). *Solar + storage synergies for managing commercial-customer demand charges*. Berkeley, CA: Lawrence Berkeley National Laboratory. Retrieved from: <https://emp.lbl.gov/publications/solar-storage-synergies-managing>

Figure 1. Synergistic Effect on Demand Charges for PV and Storage¹⁷

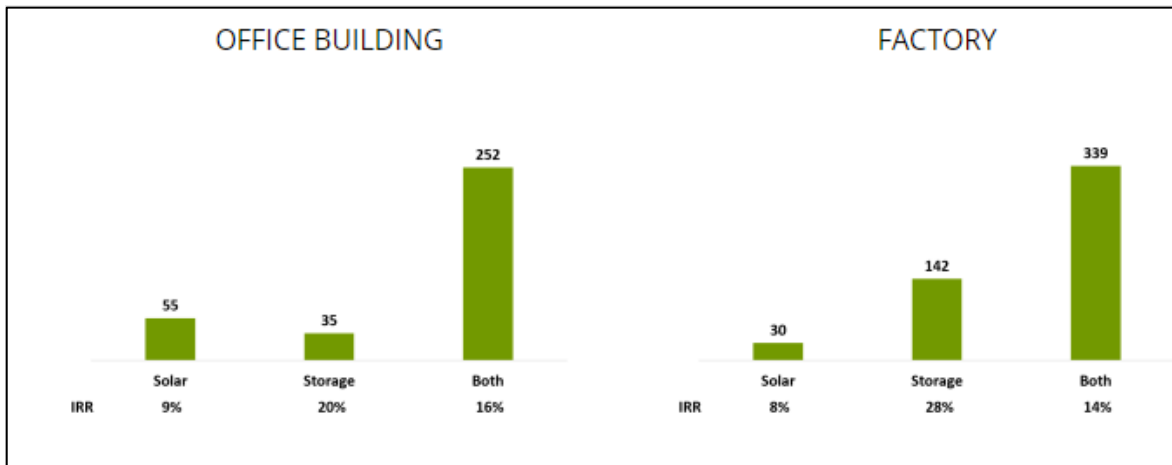
The figure shows the distribution of average monthly billing demand reductions across all building types, locations, solar sizes, and storage sizes. Each data point is the average percentage reduction, for a single load/solar/storage combination, across all months of the 17-year historical weather period.

Looking beyond demand charges, a 2015 study by the management consulting firm Woodlawn Associates found strong synergistic effects on net present value (NPV) and internal rate of return (IRR) for hypothetical installations of PV and storage on commercial buildings in California, Hawaii or New York.¹⁸ One such example from that report is presented in Figure 2.

¹⁷ Gagnon et al., 2017, 2

¹⁸ Sussman, M., and Lutton, J. (2015, November 17). *Energy storage 301: Solar + storage economics*. Chicago: Woodlawn Associates.

Retrieved from: <https://woodlawnassociates.com/energy-storage-301/>

Figure 2. Synergistic Effects on Net Present Value and Internal Rate of Return for PV and Storage¹⁹

The additive and synergistic value of DER combinations will remain unrealized, unless and until mechanisms are established to compensate the owners/hosts of those DER systems.

DERs are being installed and operated in ways that almost always reduce system energy costs and often reduce generation capacity costs.

Reforming IRP to Support Synergistic DER Portfolios

Many of these values do not show up in current quantitative tools and methodologies. Traditional cost-effectiveness tests do not account for the synergistic benefits of different resources. Likewise, traditional integrated resource planning does not adequately consider the variety of beneficial DER deployment scenarios. One cause is the planning time horizon required by different technologies. The fleet of generators now providing most of our power consists mostly of large units, which take years to come online. Transmission and distribution infrastructures also require long lead times, sometimes complicated by regulatory uncertainty. Utility planning evolved around that framework to accommodate the scale of large, centralized physical assets. DER, consisting of a large number of smaller units with variable output scattered across the utility's territory, requires a more granular approach.

For example, utilities need to develop long-term load forecasts, accounting for utility-scale variable energy resources and DERs — including variable distributed generation, storage and flexible loads. Utilities must consider the impacts of behind-the-meter DERs they cannot control and must anticipate needs at a granular local level. When utilities use their own generation resources to meet load, they must understand in detail their energy, capacity and ancillary service needs to identify the least-cost, least-risk suite of resources that will suffice.

The degree of granularity is an increasing challenge. Variations in subhourly supply and demand are critical for revealing the need for ancillary services and capturing the full value of flexible loads,

¹⁹ Sussman and Lutton, 2015.

traditional DR and storage resources. The production cost models used to develop IRPs often cannot model supply and demand in subhourly increments. Most of the production cost models available today are proprietary software sold by private companies, but utilities and regulators can stimulate the demand for more sophisticated models with more computational ability and work with vendors to develop practical solutions to this challenge.

Although the IRP process purports to find the least-cost solution to long-term power needs, many utilities artificially constrain the contributions that DERs can make in order to simplify the modeling exercise. For example, rather than establishing EE procurement levels by optimizing for total long-term system cost, most IRPs assume certain amounts of EE will be procured annually — for example, just enough to meet the minimum requirements of a state-mandated energy efficiency resource standard. These kinds of constraints do not serve well for planning a modern grid. Customers will be best served if the IRP process assesses all resources — utility scale and distributed, supply side and demand side — on an equal basis. The Seventh Power Plan developed by the Northwest Power and Conservation Council offers a good example of an IRP that avoids placing artificial constraints on the contributions of DERs.²⁰

The best IRP processes include an assessment of risks and uncertainties. The preferred portfolio of resources is not necessarily the one that is least costly under base case assumptions but could be one that is relatively inexpensive under a wide variety of potential scenarios, including the base case. A process that considers risk and uncertainty in this manner acknowledges limitations to predict the future. It also tends to reveal a higher value, all else being equal, of resources that can be procured in small increments (like DERs) and resources that are flexible (storage, DR and flexible loads).

Many IRPs also include consideration of costs and benefits not directly related to operation of the power system, that is, nonenergy impacts. It is commonplace to attach an assumed monetary cost to GHG emissions, for example, even in jurisdictions where such emissions are not currently regulated and generators pay no cost for emissions. Such costs then become part of the calculus of determining which portfolio of resources can meet long-term needs at least cost (considering risk). This is the IRP equivalent of using a SCT or RVT instead of a UCT. Consideration of nonenergy impacts will better reveal the full value of DERs and should be a routine part of IRPs, even if decisions about the preferred portfolio are based primarily on a UCT.

Conclusion

The valuation of DERs is a pressing and very difficult issue in part due to the very different capacities that each resource provides, how those vary depending on use case and operational implementation. The attempt to fit DERs which offer very different capabilities from traditional generation, transmission and distribution functions may do a significant disservice to what DERs offer. Had automobiles including freight trucks been evaluated using functional categories for railroads and horses and wagons (cost per ton shipped and cost per mile per person) it would

²⁰ NPCC (2016, February). *Seventh power plan*. Portland, OR: Northwest Power and Conservation Council (NPCC). Retrieved from: <https://www.nwcouncil.org/reports/seventh-power-plan>

hardly be clear that automobiles would become a predominant transportation mode in the 20th century. Automobiles offered flexibility and optionality as to points of departure and destinations as well as speed advantages. Before the national highway system was built over decades — a massive investment in infrastructure which redesigned the transportation system writ large — the flexibility of automobiles and trucks were a lot less valuable and harder to capture.

Realizing the capabilities and flexibility of DERs may require a similar redesign of the power grid just as building of state and national highways and local roads affected a reorientation of the transportation system to take advantage of the capabilities of automobiles. Redesigning substations to allow for two-way power flows may simply be the beginning of this grid redesign.

Appendices Applying DER Valuation to Specific Technologies

The following appendices apply the value stacking analysis in the paper to specific technologies. These include demand response, solar, distributed battery storage, combined heat and power, and fuel cell power generation. This analysis used data from technology specific studies and included data in the value stacking analysis. If the authors were not able to find data for a specific section of the value stack, the section is not included. Thus, not all of the values represented in the paper value stack are replicated for each of the technologies in the appendices.

Appendix A: Demand Response

1. Background

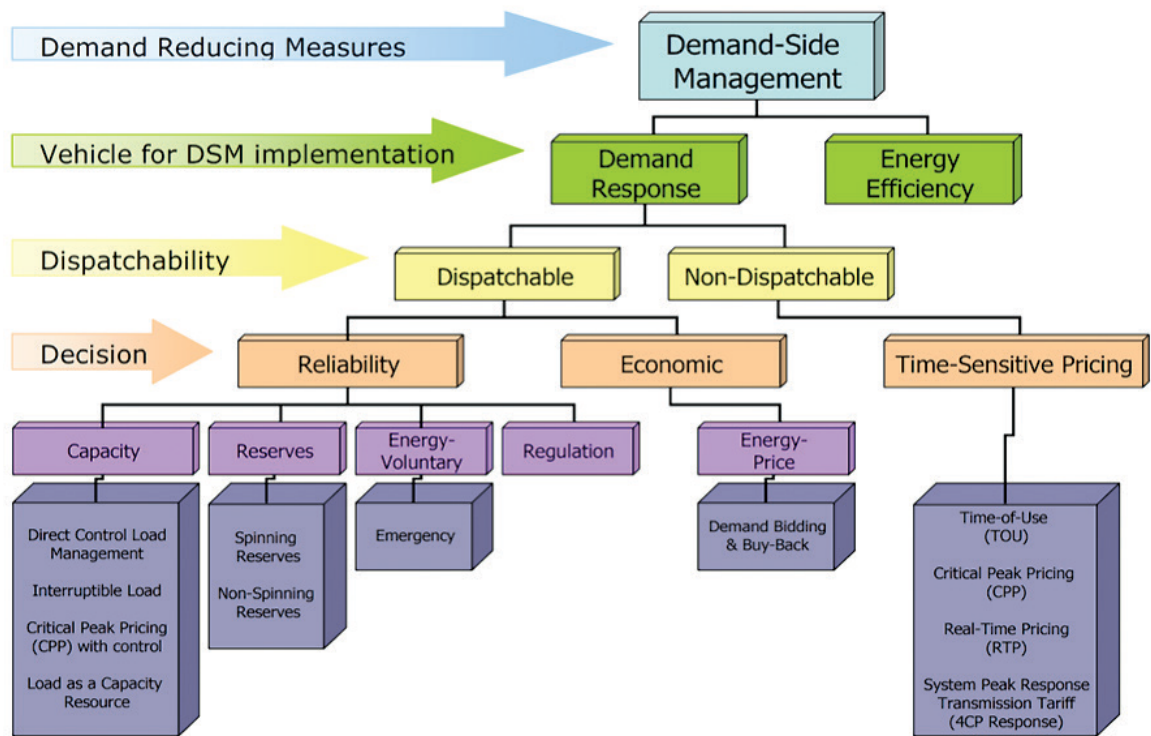
a. DR advanced basics

The Federal Energy Regulatory Commission (FERC), pursuant to its regulations of wholesale power markets, defines demand response (DR) as: “Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.” DR is possible in any customer class and comes in different forms and employs varied technologies and strategies to change load profiles. Typical types of dispatchable demand response include:²¹

- Reducing or interrupting consumption temporarily with no change in consumption in other periods (shed)
- Shifting consumption to other time periods (shift)
- Temporarily utilizing on-site generation in place of energy from the grid (could be shed or shift)
- Providing frequency regulation and other fast-response ancillary services (shimmy).

Some DR programs are price based: They shape load by customers responding to price signals such as time-of-use rates, critical peak pricing or peak time rebates. These programs might not be dispatchable, meaning that system operators do not necessarily know to what degree customers will adjust consumption. However, with smart meters, DR programs can be aggregated and automated to provide dispatchable utility load reduction services. Direct load control is generally offered to retail customers through utility incentive payments. All the other types of DR are implemented through customers’ or aggregators’ participation in markets. Figure 3 shows a categorization of demand response types under the general category of demand-side management measures.

²¹ Alstone et al., 2017.

Figure 3. Demand Response Categories²²

Demand response participation in any market is a function of whether the market rules and structures allow it to economically participate. FERC Order 745 in 2011 mandated that demand response providers in FERC-jurisdictional markets be compensated for reducing electricity load at the locational marginal price (LMP) or wholesale market energy price — the same rate for generation resources. Order 745 was challenged by some economists and a group of generators on the level of compensation as well as FERC’s basic authority over demand response. In 2016, the U.S. Supreme Court judged that FERC acted within its authority to ensure “just and reasonable rates” in the wholesale markets. Following the Supreme Court’s decision, the commission also issued several orders related to demand response, including the approval of ISO-New England’s (hereafter ISO-NE) proposal to fully integrate demand response resources into its wholesale energy markets.²³ FERC’s Order 745 and the Supreme Court decision have confirmed DR’s participation in organized markets and opened up opportunities for FERC to develop policies to encourage a wide range of distributed energy services, such as distributed generation, rooftop solar PV and battery storage.

²² NERC (2011). *Demand response availability data system (DADS): Phase I & II final report*. Princeton, NJ: North American Electric Reliability Corporation (NERC). This information from the North American Electric Reliability Corporation’s website is the property of the North American Electric Reliability Corporation and can be found at <https://www.nerc.com/pa/RAPA/dads/DADSPHaseII/DADS%20Phase%20I%20and%20II%20Report.pdf#search=Demand%20response%20a%20availability%20data%20system%20%28DADS%29%3A%20Phase%20I%20%26%20II%20final%20>. This content may not be reproduced in whole or any part without the prior express written permission of the North American Electric Reliability Corporation.

²³ FERC (2015, December). *Demand response & advance metering staff report*. Washington, DC: Federal Energy Regulatory Commission (FERC). Retrieved from: <https://www.ferc.gov/legal/staff-reports/2015/demand-response.pdf>

b. Demand response in the ISO-NE market

ISO-NE²⁴ integrates demand response resources into its wholesale markets. In 2010, when its forward capacity market (FCM) was adopted, demand response was allowed to directly participate in the FCM with two demand response capacity programs: real-time demand response and real-time emergency generation.²⁵

In 2016, a total of 2599 MW DR participated in the ISO-NE FCM, representing 10.2% of its peak demand.²⁶ On June 1, 2018, a new price response demand (PRD) framework went into effect in ISO-NE. Under the PRD framework, active demand resources can now participate in the energy and reserve markets and are dispatched economically, based on their energy market offers.

Under the current PRD framework, active demand resources:

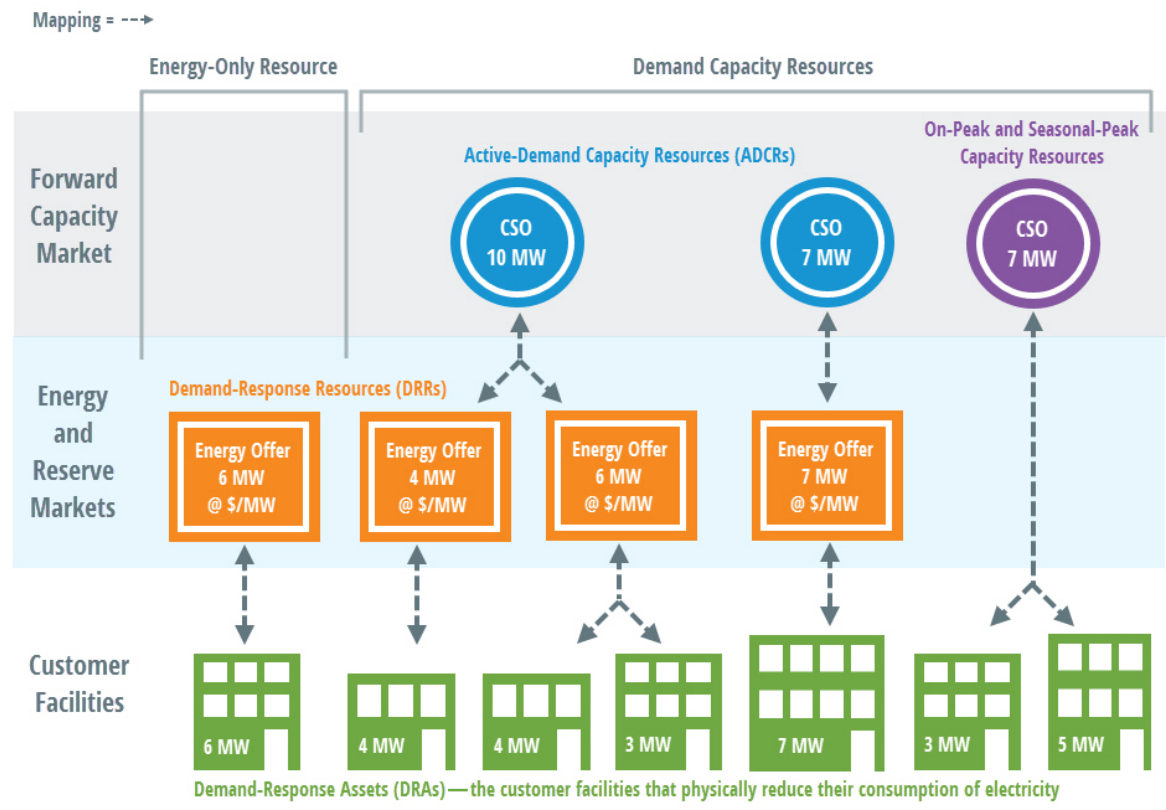
- Receive wholesale market payments comparable to that of generating resources for providing energy, operating reserves and capacity to the New England electric system;
- Are able to submit offers to both day-ahead and real-time energy markets;
- Can be committed by the ISO a day ahead and dispatched in real time;
- Are co-optimized to provide energy and/or reserves in the most economically efficient manner; and
- Are able to set the price for wholesale electricity.

Passive demand resources, which are not dispatchable, are ineligible to participate in the energy markets but can participate in the capacity market as on-peak resources and seasonal-peak resources called by the operator when needed. Figure 4 illustrates demand resources' participation in ISO-NE markets.

²⁴ For more details, see ISO-NE (undated). About demand resources [web page]. Retrieved from: <https://www.iso-ne.com/markets-operations/markets/demand-resources/about>

²⁵ Real-time demand response refers to a reduction in energy usage at an end-use customer facility, while real-time emergency generation refers to an on-site generator behind the customer meter that has environmental permits limiting its operation to "emergency" hours when the system operator calls upon them in order to prevent the load shedding.

²⁶ FERC (2017, December). *Assessment of demand response and advanced metering*. Washington, DC: Federal Energy Regulatory Commission (FERC), p. 19. Retrieved from: <https://www.ferc.gov/legal/staff-reports/2017/DR-AM-Report2017.pdf>

Figure 4. Demand Resource Participation in ISO-NE Markets²⁷

c. Approaches to DR valuation

For the purpose of this paper, we focus on the active demand response installations that participate in the ISO-NE forward capacity market, energy market and ancillary services market. Before applying the layer-cake valuation approach to these DERs, we make some observations about them and their attributes and how these affect DR valuations.

- DR resources are often used to displace peak resources. As a result, they can have significant capacity value. That said, calculating the avoided capacity value can be complex due to DR timing and uncertainties.²⁸ For regions with organized markets, the avoided capacity costs are determined by capacity market prices. In the short run, the capacity price depends on the mix of existing capacity resources that set the capacity prices in each successive auction; in the three-year forward capacity market, the cost of a new power plant entrant into the capacity market sets the price. Recent ISO-NE capacity auctions continue to indicate that combined

²⁷ ISO-NE, undated.

²⁸ Woolf, T., Malone, E., Schwartz, L., and Shenot, J. (2013, February). *A framework of evaluating the cost-effectiveness of demand response*. Cambridge, MA/Montpelier, VT: Synapse Energy Economics/RAP. Retrieved from: <https://emp.lbl.gov/sites/all/files/napdr-cost-effectiveness.pdf>

cycle gas turbine and gas-fired combustion turbines are the marginal clearing resources. The next section of this paper investigates ISO-NE's FCM based on results of the 2018 report from the avoided energy supply component (AESC) study group.

- DR resources can avoid energy costs by reducing energy consumption or shifting demand from high- to low-priced periods. In the short run, the avoided energy cost should equal the marginal operational cost of existing generators when the active DR operates in an energy market. In ISO-NE, the avoided energy cost can be forecasted using energy market price data. The latest AESC report estimated avoided energy costs on an hourly basis throughout the year, and those avoided costs can be applied to various active demand response resources.
- DR can provide ancillary services to the system if it can respond quickly and reliably to system imbalances. ISO-NE recently allowed DR to compete with other supply-side generators to provide operating reserves.²⁹ ISO-NE is also removing barriers to better compensate fast-responding frequency regulation services in line with FERC Order 755.³⁰ Specifically, a DR asset can provide regulation service as an alternative technology regulation resource (ATRR) in ISO-NE.³¹ As a flexible and low-cost resource, DR is likely to play a more significant role in providing ancillary and reliability services in the future, especially as better control technologies come online. Efforts to quantify this value are improving. Avoided ancillary services costs can be calculated following the process described in Brattle's 2015 report.³² That is, if DR provides ancillary services that are comparable to those of a generating resource then the same basic approach to estimating avoided costs can be used; if the operating characteristics make DR not comparable to other generators, then a more complicated approach, such as a resource planning model, may be needed. NREL performed a modeling demonstration to value DR, providing a variety of grid services to the Colorado power system.³³

The next section discusses monetization methodologies for appropriately capturing other values that DR can provide, including avoided T&D costs, demand response induced price effects (DRIPE) and avoided environmental compliance costs. Some benefits, such as customer values and societal values, are usually not taken into account in utility PAC, RIM or TRC tests. For that reason, societal

²⁹ In ISO-NE, operating reserve has three products: 10-minute spinning reserve, 10-minute non-spinning reserve and 30-minute operating reserve. DR, DG and storage have different eligibilities in providing these services. For more details, see: https://www.iso-ne.com/static-assets/documents/2018/10/er19-84-000_enhanced_storage_revisions.pdf

³⁰ Hurley, D., Peterson, P., and Whited, M. (2013, May 2). *Demand response as a power system resource*. Montpelier, VT: RAP.

Retrieved from: https://www.raponline.org/knowledge-center/demand-response-as-a-power-system-resource/?sf_action=get_data&sf_data=results&sf_s=demand+response

³¹ "In the condition that the device supplying regulation service is registered separately from the asset, is individually telemetered and directly receiving an automatic generation control signal, and is compliant with all of the ATRR requirements," according to the director of Demand Response Strategy in ISO-NE in his email response to the RAP staff.

³² Hledik, R., and Faruqui, A. (2015, January). *Valuing demand response: International best practices, case studies, and applications*, p. 24. Cambridge, MA: The Brattle Group. Retrieved from: http://files.brattle.com/files/5766_valuing_demand_response_-_international_best_practices_case_studies_and_applications.pdf

³³ Graphics showing the range of modeled DR values for different DR technologies are presented in Hummon, M., et al. (2013, December). *Grid integration of aggregated demand response, part 2: Modeling demand response in a production cost model*. Golden, CO: National Renewable Energy Laboratory (NREL). Retrieved from: <http://www.nrel.gov/docs/fy14osti/58492.pdf>

tests are necessary to fully assess the value DR offers to customers, the public and utilities and grid operators. This chapter concludes with a survey of recent studies.

2. Value stacking

The 2018 AESC report provides New England specific inputs³⁴ for a number of different values in our illustrative layer cake to show how value stacking can achieve multiple values. The AESC models 18 years from 2018 through 2035 in the six ISO-NE states: Maine, Vermont, New Hampshire, Connecticut, Rhode Island and Massachusetts. Market rules in ISO-NE, including marginal cost bidding, installed capacity requirements (with reserve margin) and ancillary services requirements (regulation, spinning and nonspinning reserve markets), are presented in the AESC models. Market structural changes underway, such as competitive auctions with sponsored resources initiative (CASPI), are modeled as implemented.³⁵

For the annual energy and peak load forecast, the AESC base forecasts assume:

- No new energy efficiency or other demand-side measures are installed in 2018 and later. Passive demand response and distributed generation have been forecasted separately to estimate the actual load demand (net load), but they are not in the 2018 AESC base load forecast.
- No incremental electrification result from EV or other types of strategic electrification.
- No incremental battery storage after 2018 to avoid double counting.

a. Values and costs akin to grid-scale generation

i. Avoided capacity costs

AESC 2018 forecasted the capacity price in the FCM of ISO-NE for 15 years. The cost of meeting capacity requirements is set three years in advance of actual capacity needs through the FCM auction. Table 3 shows a time series of projected capacity prices, as well as a 15-year levelized cost in the 2018 AESC report. For example, if a DR provider clears or reduces load in summer 2018, it will receive capacity payments at the price determined in auction FCA9 (held in 2015) for the period from June 2018 to May 2019. This study shows that a load reduction in the summer of 2018 is worth 12 times the 2018/19 price (expressed in \$/kW-month), or \$118 /kW multiplied by the capacity value accepted by ISO-NE for that resource.³⁶ Any DR or broader DER program savings not cleared (or not bid) in the capacity market will nonetheless have the effect of reducing load. But under the current ISO-NE market practice, such load reductions may wait five years to be reflected

³⁴ This section is largely based on an AESC 2018 study: Synapse Energy Economics, Resource Insight, Les Deman Consulting, North Side Energy, and Sustainable Energy Advantage (2018). *Avoided energy supply components in New England: 2018 report*. Cambridge, MA: Synapse. Retrieved from: <http://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-June-Release.pdf>

³⁵ This initiative exempts sponsored resources (including renewables and other certified resources receiving out of market revenues supported by state or municipal policies) from directly bidding into the forward capacity market (FCM), instead, it sets up secondary auctions for sponsored resources to substitute retiring resources. For details, see 162 FERC ¶ 61,205 (docket no. ER18-619-000). Retrieved from: <https://www.ferc.gov/CalendarFiles/20180309230225-ER18-619-000.pdf>

³⁶ Reductions must be verified using ISO-NE measurement and verification protocol.

in a lower demand forecast and installed capacity requirement (to be purchased in the FCM). With DERs coming onto the grid that are not reflected in the FCM, ISO-NE market rules consistently overstate capacity and reserve requirements.³⁷

Table 3. AESC 2018 Capacity Prices³⁸

Commitment Period (June to May)	FCA	AESC 2018
2018/2019	9	\$9.81
2019/2020	10	\$7.28
2020/2021	11	\$5.35
2021/2022	12	\$4.74
2022/2023	13	\$4.84
2023/2024	14	\$4.94
2024/2025	15	\$5.22
2025/2026	16	\$5.65
2026/2027	17	\$6.13
2027/2028	18	\$6.60
2028/2029	19	\$7.07
2029/2030	20	\$7.54
2030/2031	21	\$6.60
2031/2032	22	\$7.07
2032/2033	23	\$7.54
2033/2034	24	\$6.60
2034/2035	25	\$7.07
2035/2036	26	\$7.54
15-year levelized		\$6.42

ii. Avoided energy costs

The forecast of wholesale energy prices in 2018 AESC used the EnCompass model to calculate prices. EnCompass projects prices over time with changing system demand, unit availability, transmission constraints and other attributes. The EnCompass-modeled energy prices do not include RECs but do reflect costs of compliance with state and federal environmental regulations on traditional generators, such as the regional greenhouse gas initiative (RGGI) and sulfur dioxide (SO₂) regulations.³⁹ Monthly LMP projections for the Western and Central Massachusetts (WCMA) zone are available in the public version of the AESC. The 2018 AESC forecasts monthly LMPs lower than the previous 2015 AESC report because of lower demand, more renewables, lower predicted natural gas prices and expected electricity imports via a new transmission line from Canada.

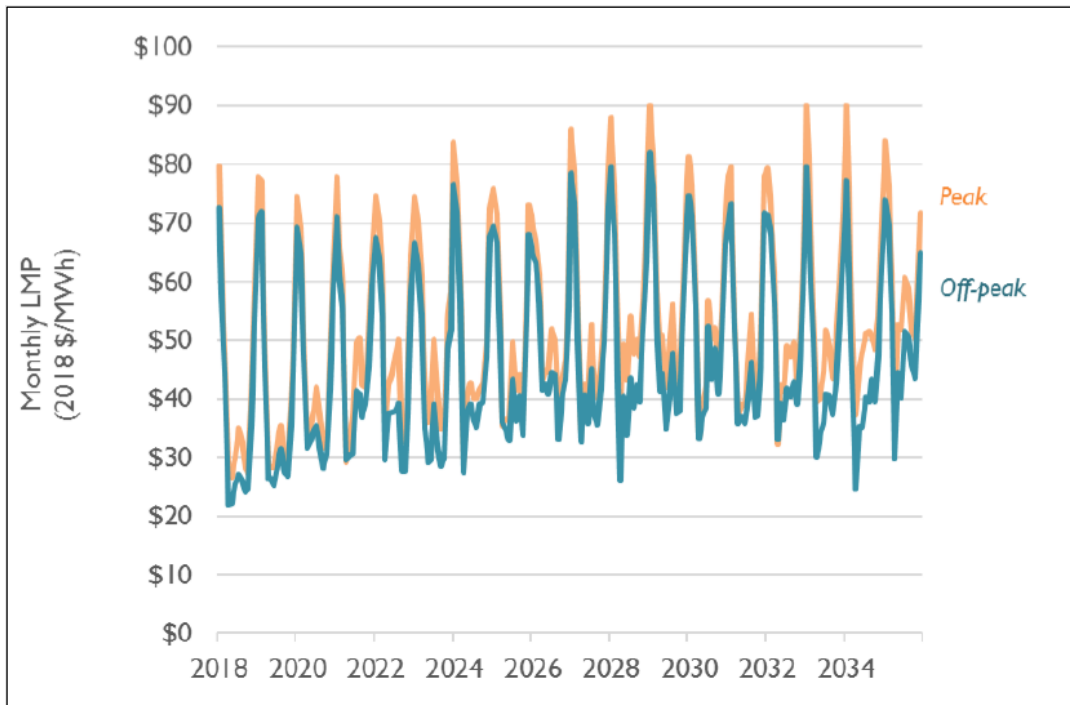
³⁷ Some types of demand-side resources (such as on peak or seasonal peak resources) will have more uncertainties and constraints in regard to frequency, timing and duration of the operation and thus not bid into the forward capacity market (FCM) or fail to qualify. The avoided costs of these demand response measures nonetheless require consideration because it affects peak and seasonal demand (see Synapse Energy Economics et al., 2018, 105–106).

³⁸ Synapse Energy Economics et al., 2018, 102.

³⁹ The AESC 2018 report uses RGGI (regional greenhouse gas initiative) price trajectory in line with the “high sensitivity” modeled by ICF on behalf of RGGI, Inc. SO₂ prices are based on actual allowance prices from 2015 under the Cross State Air Pollution Rule and the Acid Rain Program, escalated at the rate of inflation through the study period.

With capacity prices and hourly projected energy prices, the next step in the analysis of DR value is to determine when the DR technologies are likely to be utilized. In the current ISO-NE market, DR is increasingly used more for economic than for reliability purposes,⁴⁰ so it is more likely that DR will occur during high-price hours than high-load hours.⁴¹ This is important because on a modern grid high prices might occur when solar and wind output is lower rather than when load is highest. The average marginal peak energy price during the hours of DR dispatch is multiplied by the total amount of energy reduced during that period to determine the total avoided energy costs of DR programs.

Figure 5. AESC 2018 Wholesale Energy Price Projection for WCMA⁴²



ISO-NE's new market rule permitting DR to participate in the day ahead and real time wholesale energy market could reduce hourly energy prices. However, a Synapse analysis did not find a direct correlation between the participation of DR and real time energy market prices between March 2006 and March 2012.⁴³ Synapse hypothesizes an unwillingness of DR to participate in the energy market due to fluctuating energy prices that seem too risky for most customers and DR providers. With new market rules around DR, ISO-NE postulates that this may change in the future.

⁴⁰ Smith, D. (2017, November 7). *Price-responsive demand (PRD) overview: Customer training webinar*, p. 11. Holyoke, MA: ISO-NE. Retrieved from: <https://www.iso-ne.com/static-assets/documents/2017/11/201711107-webinar-prd-overview.pdf>

⁴¹ Traditionally, high-load hours and high-price hours are much the same. But with more renewables coming to the system, high-load hours may not coincide with high-price hours because renewables output reduces load and the wholesale market prices.

⁴² Synapse Energy Economics et al., 2018, 112.

⁴³ Hornby, R. et al. (July 12, 2013). *Avoided energy supply costs in New England: 2013 report*, pp. 41–43. Cambridge, MA: Synapse. Retrieved from: https://www.synapse-energy.com/sites/default/files/SynapseReport.2013-07.AESC_.AESC-2013.13-029-Report.pdf

iii. Wholesale risk premium

In the wholesale market, some risks, such as weather conditions, economic activity and customer load variations, are difficult to predict. The cost of hedging these risks will be borne by the retail electricity suppliers. These costs, like wholesale market prices for energy, capacity and ancillary services, are passed through to retail prices. The cost effect of hedging these risks could be reduced by demand-side resources. The 2018 AESC report applies the same wholesale risk premium (8%) to avoided wholesale energy and capacity prices. According to a private analysis, the risk premium could range from 5% to 10%.

iv. Reduced RE obligation of RPS costs

Under most renewable portfolio standards, an LSE's (load servicing entity) annual compliance cost equals the quantity of RECs purchased by the LSE multiplied by the price paid per REC. Those costs are then passed on to customers in the pricing paid by retail providers to the LSEs. The RPS compliance cost that retail customers avoid through reductions in their energy use is equal to the price of renewable energy credits multiplied by the percentage of retail load reduced and the percentage of load subject to the RPS. These savings would then be increased to reflect avoided line losses and other distribution costs.

The AESC study estimates the REC prices as well as the RPS targets for existing and new renewable energy resources in each ISO-NE state for each modeled year. The study used the renewable energy market outlook model. The 15-year levelized avoided RPS costs (2018–2032) shown by the model are in Table 4.

Table 4. Avoided Cost of RPS Compliance⁴⁴

	CT	ME	MA	NH	RI	VT
Class 1/New	\$2.82	\$0.21	\$1.72	\$1.51	\$2.39	\$0.53
MA CES	NA	NA	\$0.45	NA	NA	NA
All Other Classes	\$0.94	\$0.31	\$1.44	\$3.43	\$0.03	\$1.46
Total	\$3.76	\$0.51	\$3.61	\$4.94	\$2.42	\$1.99

v. Avoided environmental compliance costs

Some environmental compliance costs (RGGI, SO₂) are embedded in energy costs, while others (other GHG costs beyond RGGI and NO_x emissions public health impacts) are not. The costs of these other compliance obligations are not traded currently but could be covered by future regulations, especially as additional limits on CO₂ are considered. Individual states or jurisdictions can adjust the avoided nonembedded environmental compliance costs based on the policies in place.

The total environmental costs (or societal values) can be estimated by using marginal abatement costs. The AESC 2018 report assessed carbon capture and sequestration and offshore wind as the marginal CO₂ abatement technologies to replace gas peaking plants at a cost of \$100 or \$68 per

⁴⁴ Synapse Energy Economics et al., 2018, 139. Retrieved from : <https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf>

short ton of CO₂ equivalent respectfully even assuming rapid technological cost reductions for offshore wind.⁴⁵ NO_x damage could cost in excess of \$31,000 per ton N based on literature review.⁴⁶ The avoided wholesale energy cost for NO_x of \$0.00165/kWh can be calculated assuming a 50/50 mix of NO and NO₂ and appropriate NO_x emissions rates for a new natural-gas-fired combustion turbine.

vi. DRIPE effects

According to Synapse, “Demand Reduction Induced Price Effect (DRIPE) is the reduction in prices in the wholesale markets for capacity and energy — relative to the prices forecast in the Reference case — resulting from the reduction in quantities of capacity and of energy required from those markets due to the impact of efficiency and/or demand-side reduction programs. Thus, DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices seen by all retail customers in a given period.” While explicitly included here, it depends on the perspective or cost test used to determine DRIPE benefits. Under the SCT and also under the other tests in places where LSEs do own generation, there is some debate about whether DRIPE constitutes an avoided energy benefit or only serves as a wealth transfer from suppliers to customers.⁴⁷

The electric capacity DRIPE was modeled in the AESC 2018 report using equilibrium analysis; the electric energy DRIPE was modeled using regression analysis. Gross DRIPE will be partially offset by customers who increase their consumption or by producers who reduce the supply. Thus, to approximate the DRIPE effects experienced by retail customers, some judgment is required regarding the pace of offset or dissipation,⁴⁸ as well as other market factors.⁴⁹

The AESC 2018 report calculates an ISO-wide capacity DRIPE of \$486.95/kW-year in 2018 for cleared capacity installed in 2018. It is worth noting that uncleared demand response also has capacity DRIPE effects, although the benefits will appear five years after a unit becomes operational as discussed above. Similar to cleared DR, capacity DRIPE effects depend on the slopes of supply and demand curves in each program year accounting for decay.⁵⁰

⁴⁵ This assumes that the offshore wind's price will be reduced to a half of current price by 2028 due to rapid technological advances. Synapse Energy Economics, et al. 2018, 143.

⁴⁶ Sobota, D. J., Compton, J. E., McCrackin, M. L., and Singh, S. (2015, February 17). Cost of reactive nitrogen release from human activities to the environment in the United States. *Environmental Research Letters*, 10(2). Retrieved from: <https://iopscience.iop.org/article/10.1088/1748-9326/10/2/025006>. Calculated from Table 1 air borne NO_x damage costs S/kg/N calculated to tons, assuming \$1.00 in 2008 = \$1.174 in 2018.

⁴⁷ SEE Action (2015). *State approaches to demand reduction induced price effects: Examining how energy efficiency can lower prices for all*. San Francisco: State and Local Energy Efficiency Action Network, U.S. Department of Energy. Retrieved from <https://www4.eere.energy.gov/seeaction/publication/state-approaches-demand-reduction-induced-price-effects-examining-how-energy-efficiency>

⁴⁸ The AESC 2018 report assumes that the capacity DRIPE (demand reduction induced price effect) will be offset over a period of six years and DRIPE benefits for cleared capacity will end with the date of the program cessation even if the decay schedule continues. The energy DRIPE continue for 10 years until the DRIPE benefits are fully decayed unless the savings end before that.

⁴⁹ Each state has a difference percentage of supply acquired from wholesale capacity and energy markets, taking into account hedged load and short-term contracts.

⁵⁰ All other things being equal, the DRIPE effects from uncleared resources will have fewer effects than cleared resources because of discounting; however, all other things may not be equal if cleared demand response does not participate in both markets.

The energy DRIPE coefficients are developed by aggregating hundreds of hourly slope values showing how energy price changes for a small change in demand based on the regression model. These energy DRIPE coefficients are restated as load-weighted price elasticities to calculate intrazonal and interzonal energy DRIPE for the load subject to the market price accounting for decay. Table 5 summarizes seasonal energy DRIPE values for 2018 installations by zone, season and period.

Table 5. Seasonal Energy DRIPE Values for 2018 Installation⁵¹

Type	Season	Period	ISO	ME	NH	VT	CT	RI	SEMA	NEMA	WCMA	MA
Zone-on-Zone	Summer	Peak	33.34	2.95	3.37	0.64	7.34	2.52	4.67	7.72	4.50	16.90
		Off-Peak	22.34	2.11	2.29	0.44	5.02	1.65	3.06	5.56	3.04	11.66
	Winter	Peak	44.26	4.34	4.66	0.94	9.33	3.28	6.07	9.98	6.03	22.08
		Off-Peak	31.59	3.32	3.42	0.68	6.65	2.28	4.23	6.93	4.33	15.49
Zone-on-ROP	Summer	Peak		30.77	30.34	33.08	26.37	31.19	29.04	25.99	29.21	16.81
		Off-Peak		21.04	20.87	22.71	18.13	21.51	20.09	17.59	20.11	11.49
	Winter	Peak		40.29	39.97	43.69	35.30	41.35	38.56	34.65	38.60	22.55
		Off-Peak		28.52	28.42	31.16	25.19	29.56	27.61	24.91	27.50	16.35

A remarkable improvement of the AESC 2018 study is that it provides estimates of the energy DRIPE in certain peak hours, which could be insightful for DR programs and applications that target either high demand or high prices. The study finds that a DR program targeting the top 10 hours of the summer months in 2016 has a DRIPE value of about three times the standard summer peak DRIPE. The AESC also states that a DR program which effectively targeted real time prices could have even higher peak hour DRIPE.

vii. Value of reliability

While reliability⁵² will improve as a result of using less energy and increasing the availability of resources capable of providing ancillary services, it is difficult to quantify the DR-induced reliability value for transmission and distribution. Three elements are studied in the AESC 2018 report: (1) value of lost load (VOLL), (2) the generation component and (3) the T&D component.⁵³ With respect to value of generation reliability improvement, enhanced resource adequacy can produce measurable increase in reliability value. The 15-year levelized benefit of increasing generation reserve margins through reduced energy use is estimated to be \$ 0.65/kW-year for cleared resources at a VOLL of \$25/kWh. T&D reliability is affected by multiple nonload factors,

⁵¹ Synapse Energy Economics et al., 2018, 171.

⁵² Reliability denotes both system security (reliability in real-time operations) and resource adequacy (sufficient investment over the long-term to meet expected demand).

⁵³ (1) Value of lost load (VOLL) shows the damage customers incur not being able to use power from the grid. The AESC 2018 report uses VOLLs of 12/kWh and 37 /kWh, representing the range of different methodologies. (2) Concerning the generation component and increased reserve margins: because the ISO-NE FCAs are designed to increase the amount of capacity acquired as the price falls, if the demand response programs reduce the capacity clearing price, the reserve margins and reliability will increase. To calculate the reliability value, first estimate MRI (marginal reliability index), which shows the changes in LOEE (loss of energy expectation) for each additional reserve margin, then multiply it by VOLLs. (3) Although the benefits of DR to improve T&D (transmission and distribution) reliability are well mentioned, the AESC 2018 report could not quantify this value because many other nonload factors also impact T&D reliability.

so it is difficult to quantify DR-related reliability benefits.

viii. Reduced line losses enhance generation value

Power systems are planned and operated to meet the total system load, which includes losses in the T&D systems that transmit generator power to customers. Thus, if DR reduces one kWh at the customer site, it reduces wholesale energy by more than one kWh. Line losses from generator to the point at which the PTF system connects to local non-PTF transmission or to distribution substations are included in the avoided energy and capacity costs and the estimates of DRIPE. The AESC 2018 report uses a marginal PTF demand loss factor for capacity costs of 1.6% adjustment. The line losses from non-PTF transmission and distribution level should be added separately. For simplification, the AESC report uses the figure of 8% to account for losses from the ISO wholesale level to the end user.

b. Values and costs akin to traditional bulk transmission and distribution

DR can contribute to deferred or reduced investment in T&D facilities. The actual value of avoided T&D additions often depends on the location and operation of the DR. The AESC study only calculates the average ratio of all load-related investments to all load growth, so it likely understates savings for particular locations. For example, load management at specific substations or transformers to release congestion can add significant value. In a particular period, the avoided T&D costs can be calculated as follows:

SIDEBAR

Avoided T&D costs

$$= \text{load related T\&D investments incurred} / \text{the actual or expected relevant load growth} \\ * \text{real levelized T\&D carrying charge} + \text{allowance for O\&M}$$

The most challenging part of this analysis is to identify those T&D investments that are necessary due to load growth and eliminate the nonload-related investments from the numerator of the equation. The carrying charge is used to derive the avoidable capital cost in \$/kW-year for the life of the equipment.⁵⁴ The AESC 2018 report calculates an avoided cost for ISO-NE administrated pool transmission facilities (PTF) of \$94/kW-year in 2018 dollars. This does not include the avoided non-PTF transmission investments and distribution investments.

ICF conducted an analysis on avoided T&D for one large New England utility in 2017, which provides some inputs for the AESC 2018 report. The non-PTF avoided transmission cost would be \$16/kW-year using the methodology above. The avoided distribution cost of the same utility is estimated to be \$14/kW-year according to ICF, although AESC authors

⁵⁴ The annual value has other components, such as income tax, insurance, and so on.

still have some disagreements on the ICF approaches.⁵⁵

In addition, the operational needs of each layer of benefits needs to be examined under different scenarios.⁵⁶ Geotargeted DR based on locational needs that vary with time increases the value of DR to the distribution system. Furthermore, investments in new sensing technologies and inverter load controls may provide value by allowing some DR and DERs to help manage power quality.

c. Other customer values and social values

The benefits categories in this section are often integrated in traditional benefit-cost tests, but for DR these benefits are not well quantified. Two significant benefit categories for DR are customer value and environmental externalities.

i. Customer values

Customers can experience more affordable service, more comfort and more choices by enrolling in DR programs by adopting new technologies. For example, customers may manage energy consumption in response to price changes or use energy management to increase their on-site renewable generation. By doing so, customers can reduce their total bill or reduce retail pricing risk. One Rocky Mountain Institute (RMI) study found that DR can bring customers net bill savings of 10% to 40% under current rate structures.⁵⁷ Benefits such as bill reductions can be monetized. These benefits accrue to participants⁵⁸ and thus should not be included in some versions of the TRC, RIM or UCT tests.

DR, more so than other DERs, may also entail participant costs that can be significant enough that they determine whether or not a customer participates. For commercial and industrial customers, these costs include lost productivity associated with shed forms of DR or the costs of running backup generators or industrial generation.

Value is the net of costs and benefits. Customer costs are considered in the participant test, some version of the total resource test and societal cost test but not in the utility cost test.

ii. Environmental externalities

In addition to avoided environmental compliance costs, environmental impacts avoided depend on specific types of generation employed and the transmission or distribution that the DR program is

⁵⁵ Synapse Energy Economics et al., 2018, 211–214.

⁵⁶ FERC questions the ability of a DR bulk power system to meet distribution system requirements, saying “DR programs designed to meet bulk power system needs may have a limited ability to meet a set of distribution system requirements.” See FERC, 2017. This is a classic concern that DR may not be able to realize one particular layer (set) of values even though it is capable of meeting more than one value.

⁵⁷ RMI (2015, August 26). *Report release: The economics of demand flexibility*. Basalt, CO: Rocky Mountain Institute. Retrieved from: <https://www.rmi.org/blog/2015-08-26-report-release-the-economics-of-demand-flexibility/>

⁵⁸ Heffner, G. (2009, February). *Demand response valuation frameworks paper*. Berkeley, CA: Demand Response Research Center, Lawrence Berkeley National Laboratory. Retrieved from: <https://gridintegration.lbl.gov/publications/demand-response-valuation-frameworks>

expected to defer. The CPUC protocols identify these externalities:

- Decreased health-care costs associated with lower emission levels, especially decreased air pollution;
- Environmental justice improvements, particularly for supplying electricity in urban areas;
- Biological impacts;
- Impacts on cultural resources;
- Diminishing visual resources (e.g., due to power plant stacks or transmission towers);
- Land use, including impacts of energy infrastructure on local ecosystems;
- Water quality/consumption;
- Noise pollution; and
- Other social nonenergy benefits.⁵⁹

According to the CPUC's protocols, LSEs are required to provide a qualitative analysis of nonenergy and nonmonetary benefits or costs even if they believe they do not apply to their DR programs. They should include quantitative values for these inputs if and when it is possible to estimate for a specific DR program. Environmental externality impacts are only appropriately included in the SCT or RVT.

iii. Other social values

Social values of DR cited in the literature include contributions to job creation and local economic development. Clean energy jobs can easily be calculated using standard economic models. For example, a typical study concludes that energy efficiency *including DR* provided 2,800 direct jobs. A \$1.0 million capital investment in EE creates 14 job-years for commercial EE installers — a figure that increases to 18 job-years for residential EE installers again under a typical analysis.⁶⁰

iv. Current valuation methods do not capture portfolio or locational DR valuation

Avoided cost approaches for DR program valuation have been used by regulators and utilities for years. California's Standard Practice Manual (SPM),⁶¹ developed to measure the cost effectiveness of energy efficiency programs, provides the basis for comparing the cost and benefits of demand response in CPUC's DR cost-effectiveness protocols. These SPM methods are based on long-term production cost models that are simple to use and effective in differentiating the attributes of DR programs. But since operational values are not captured, they are less effective in deciding how DR

⁵⁹ CPUC (2016, July). *2016 Demand response cost effectiveness protocols*. California Public Utilities Commission. Retrieved from: <http://www.cpuc.ca.gov/General.aspx?id=7023>

⁶⁰ Navigant Consulting (now Guidehouse Insights) (2016, August). *Clean energy jobs in Connecticut*. Prepared for Connecticut Green Bank. Retrieved from: <https://ctgreenbank.com/wp-content/uploads/2017/02/CTGreenBank-Clean-Energy-Jobs-CT-August102016.pdf>

⁶¹ CPUC (2001, October). *California Standard Practice Manual: Economic analysis of demand-side programs and projects*. California Public Utilities Commission. Retrieved from: <http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7741>

benefits change with changes in future demand and supply. They are also not conducive to fully examining an integrated DR portfolio or integrated DR-generation portfolio.⁶² The CPUC has made modifications to selected elements of the SPM tests to better adapt for use with DR.⁶³

DR can play an important role in managing demand and balancing intermittent generation. The future use of DR will rely more on advanced communication and control technologies that allow demand to respond seamlessly to price signals. Some studies examine how DR can interact with other system components to provide highly valued flexibility services at the bulk power system level. RMI simulated the wholesale electricity market of Texas in a high renewable future to illustrate the system value of demand flexibility.⁶⁴ This can be done for different types of DR (shape, shift, shed and shimmy), using a modeling process to identify least-cost strategies for power system investment and operations.⁶⁵ Because of DR's dynamic characteristics and the complexity of the grid, only an integrated energy system operational model will reveal DR's full potential.⁶⁶

Apart from wholesale market values, other valuation methodologies focus on the economic benefits to individual customers at the distribution level as distribution utilities seek to optimize distribution operations and meet local distribution infrastructure constraints. Even more sophisticated analysis is necessary to quantify locational value of DR or combinations of DERs. This may be possible through hosting capacity mapping and probabilistic and scenario-based methods.^{67, 68} One example is the Electric Power Research Institute (EPRI) modeling of DERs in Con Edison and SCE distribution systems.⁶⁹

⁶² Heffner, 2009.

⁶³ CPUC, 2016, 14–19.

⁶⁴ Goldenberg, C., and Dyson, M. (2018, February 14). *Pushing the limit: How demand flexibility can grow the market for renewable energy*. Basalt, CO: Rocky Mountain Institute. Retrieved from: <https://www.rmi.org/demand-flexibility-can-grow-market-renewable-energy/>

⁶⁵ Alstone et al., 2017.

⁶⁶ O'Connell, N., Pinson, P., Madsen, H., and O'Malley, M. J. (2014, November). Benefits and challenges of electrical direct response: A critical review. *Renewable and Sustainable Energy Reviews* 39, 686–699.

⁶⁷ Fine, S., De Martini, P., Succar, S., and Robison, M. (2015, September). *The value in distributed energy: It's all about location, location, location*. ICF International. Retrieved from: http://www.ourenergypolicy.org/wp-content/uploads/2015/09/Value_in_Distributed_Energy_Location.pdf

⁶⁸ Robison, M., Pickles, D., Fine, S., and Duffy, K. (2017, May 10). *Turning the locational value into real dollars*. ICF International. Retrieved from: <https://www.icf.com/resources/white-papers/2017/turning-locational-value-into-real-dollars>

⁶⁹ Rogers, B. (2016, October). *Time and locational value of DER: Methods and applications*. Electric Power Research Institute. Retrieved from: <https://www.epri.com/research/products/000000003002008410>. In particular, see Figures 5.5 and 5.6 for modeling of a DER portfolio to avoid traditional distribution investment in the Con Edison system.

Appendix B: Value of Solar

1. Background

a. Other customer values and social values

A significant value of solar study (VOSS) was recently undertaken by Daymark Energy Advisors under contract with the Maryland Utilities with the Maryland Public Service Commission (PSC).⁷⁰ The Maryland (MD) VOSS illustrates both elements of a VOSS (avoided energy and capacity) and the state-specific policy concerns with the MD PSC including state economic impacts and in-state jobs within the scope of the VOSS. The Maryland study looks at both utility scale (> 2 MW⁷¹) and BTM solar values in each Maryland investor-owned utility (IOU) service territory.

For bulk power system valuations,⁷² the MD VOSS puts the value of utility scale solar at \$0.08 per kilowatt hour in 2019 to about \$0.13 per kWh in 2028 in the Potomac Edison service territory. With macroeconomic impacts of solar development exceeding \$4 billion and 23,468 job-years, these Maryland-specific impacts translate to \$813 dollars per kW installed.⁷³ Total value for Potomac Edison territory would be about \$0.18 in 2019 rising to about \$0.22 in 2028. This does not include distribution system benefits, which are calculated in 2019 to be about 11 cents per kWh in localized benefits based on a 2 MW project that avoids \$2 million of avoided distribution costs in 2019 attributed to a hypothetical non-wires alternative installation.

2. Value stacking for solar distributed generation (PVDG)

Not every value identified in Table 2 applies to solar PV DG. That table summarizes all potential sources of DER value. Furthermore, the values are not of uniform value for all locations on the grid and for all hours of the year. Taking location and time-based value differences into account, different valuation methods and input assumptions can be used to estimate each potential source of value.⁷⁴ For this reason, this section addresses whether and how each source of value applies to particular PV DG projects and the valuation approaches for quantifying these value elements.

Approaches to determining the value elements through time and at different locations across the utility service territory continue to evolve, as more NGOs, utilities and regulatory authorities

⁷⁰ Daymark Energy Advisors, RLC Engineering, and ESS Group (November 2, 2018). *Benefits and costs of utility scale and behind the meter solar resources in Maryland*. Prepared for Maryland Public Service Commission. Retrieved from:

<https://cleantechnica.com/files/2018/11/MDVoSReportFinal11-2-2018.pdf>. (Hereinafter referred to as DEA et al., 2018.)

⁷¹ DEA et al., 2018, 15.

⁷² The MD VOSS considered bulk power system benefits and costs to be: avoided energy, energy market price effect, avoided capacity, avoided transmission costs, avoided ancillary services costs, fuel price hedge savings (though no quantitative value for hedge), and avoided REC purchase. See DEA et al., 2018, 16.

⁷³ DEA et al., 2018, 5–8.

⁷⁴ RMI (2013). A review of solar PV benefit & cost studies. 2nd ed. Boulder, CO: Rocky Mountain Institute. Retrieved from: https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprrts_eLab-DER-Benefit-Cost-Deck_2nd_Edition131015.pdf

undertake this analysis.⁷⁵ The next section provides some of the key inputs to — and results from — the recent field of VOSS studies.

a. Values and costs akin to grid-scale generation

i. Avoided capacity costs

The ability of DGPV (distributed generation photovoltaic) to replace or defer generation capacity provides a significant element of solar value. However, DGPV is not dispatchable, which means it is not available in all hours due to factors that cannot be controlled,⁷⁶ and its output cannot be known for certain a day in advance. Estimating the generation capacity value of DGPV is a two-step process.⁷⁷ The first step is to calculate the capacity credit, or the actual fraction of a DGPV system's capacity that reliably offsets conventional capacity. The second step is to translate the capacity credit into a monetary value.

ii. Estimating the capacity credit

There are multiple methods to estimate capacity credit, which can be divided into two classes: reliability methods and approximation-based methods.⁷⁸ The most common reliability-based method is the effective load carrying capacity (ELCC) method, which estimates the additional load that can be added to the system with the added PV capacity. The full ELCC method requires an iterative process of calculating loss of load probabilities (LOLPs) for all hours of the year.

Approximation methods usually examine the PV output during system stress periods such as highest net demand or highest loss of load probability (LOLP) hours. This requires less data and analytical effort. Crossborder in the Arizona Public Service (APS) study calculated capacity credit by looking at solar output in the high demand hours. It found that the west-facing systems produce more energy and contribute more toward meeting the system peak than south-facing systems, so a higher capacity credit was applied to the former.⁷⁹ In life-cycle analyses, where new resources are added and some old resources are retired, the capacity credit of PV may change. Some studies show that the capacity credit will decline as the solar penetration level increases.⁸⁰

Once the capacity credit (usually expressed in percentage of nameplate installation) is calculated,

⁷⁵ Orrell, A. C., Homer, J. S., and Tang, Y. (2018, February). *Distributed generation valuation and compensation: White paper*. Pacific

Northwest National Laboratory. Prepared for the U.S. Department of Energy. Retrieved from:

<https://www.districtenergy.org/HigherLogic/System/DownloadDocumentFile.ashx?DocumentFileKey=0103ebf1-2ac9-7285-b49d-e615368725b2&forceDialog=0>

⁷⁶ The capacity value of PV can be affected by factors such as solar radiation at the plant location, the failure rate of solar plant components, the penetration level of solar power and the load.

⁷⁷ Denholm, P., et al. (2014, September). *Methods for analyzing the benefits and costs of distributed PV generation to the U.S. electric utility system*. National Renewable Energy Laboratory. Retrieved from: <https://www.nrel.gov/docs/fy14osti/62447.pdf>

⁷⁸ Awara, S., Knight, A., and Zareipour, H. (2018, May). *Solar power capacity value evaluation: A review*. 2018 IEEE Canadian

Conference on Electrical & Computer Engineering. Quebec City, QC, Canada: IEEE. Retrieved from:

https://www.researchgate.net/publication/327327773_Solar_Power_Capacity_Value_Evaluation-A_Review

⁷⁹ Beach, R. T., and McGuire, P. G. (2013). *The benefits and costs of solar distributed generation for Arizona Public Service*, p. 12.

Berkeley, CA: Crossborder Energy. Retrieved from: <https://www.azsolarcenter.org/images/docs/reports/AZ-Distributed-Generation-CrossborderEnergy-2013-05.pdf>

⁸⁰ Samadi, S., and Singh, C. (2014). Capacity Credit Evaluation of Solar Power Plants. Presentation given at 2014 IEEE PES (Power and Energy) General Meeting, National Harbor, MD.

the value per kW of installed DGPV can be estimated by multiplying the capacity cost of avoided generation by the capacity credit. In ISO-NE, the forecast capacity market prices can be used to assign appropriate capacity value to DGPV, accounting for both the timing and the type of avoided capacity.

APS's 20-year levelized avoided capacity costs ranged from \$0.05 (south facing) to \$0.089/kWh (west facing) in 2016, based on the capital and O&M costs of a gas combustion turbine likely to be displaced in the near term.⁸¹ The MD VOSS calculated avoided PJM capacity market savings of \$0.005 per kWh to \$0.023 per kWh from 2019 to 2028.⁸² Crossborder's study for Arkansas reported EAI-MISO (midcontinent ISO) solar avoided capacity cost with 12% reserve margin was \$81.13/kW-year in 2018, which translates to \$0.0321/kWh on a life-cycle basis. In the Maine study, the 25-year levelized avoided generation capacity costs calculated at \$0.045/kWh in 2016. In New York ISO, system capacity value increased from \$0.03/kWh in 2015 to \$0.04/kWh in 2025. NorthWestern Energy's total avoided capacity value has the lowest estimated capacity value at \$0.005/kWh in 2018, using an annual average 6.1% capacity contribution factor across its solar adoption scenarios.⁸³ Each of these values is derived from somewhat different methodologies and data input.

iii. Avoided energy costs

Solar energy systems produce clean, renewable electricity on-site, reducing the amount utilities must generate or purchase from other sources, including fossil-fuel-fired power plants. The energy benefit of DGPV depends on the generation displaced when PV electricity is produced to the grid. Addition of DGPV does not result in all other generators reducing output across the system. Instead, new DGPV reduces the generation needed from the marginal unit in the system. The variable cost of the marginal generator is reflected in energy market prices. Any state with wholesale pricing can use specific hourly (or subhourly) prices to directly calculate the energy value of PV. Multiplying the PV production by the energy price in each period produces the value for that period, which can be summed to a yearly value or an average value per kWh PV generation.

The quantity of energy produced by PV varies by the time of day, time of year and weather conditions, so the contribution of DGPV to meeting energy needs varies over the course of the year. Current market price valuation methods generally assume that PV generation is too small to impact system operation or LMPs, but this may change. As solar penetration increases, valuation will require a production cost model to simulate the impact of DGPV on the generation mix and system operation needs under various scenarios.

The MD VOSS calculated energy price reduction benefits using the Aurora model. Price from avoided energy was simply the purchase costs for hours of solar generation. These benefits were

⁸¹ Beach, R. T., and McGuire, P. G. (2016). *The benefits and costs of solar DG for Arizona Public Service (2016 Update)*, p.12. Crossborder Energy. Retrieved from <http://images.edocket.azcc.gov/docketpdf/0000168554.pdf> in the Exhibit 2 starting from p. 65

⁸² DEA et al., 2018, 22.

⁸³ Navigant Consulting (now Guidehouse Insights) (2018, March 29). *Net energy metering (NEM) benefit cost analysis*, p. 7. Prepared for NorthWestern Energy—Montana. Retrieved from: <https://www.northwesternenergy.com/docs/default-source/documents/defaultsupply/plan19/volume2/navigant-nem-cost-benefit-analysis-report-5-3-2019.pdf>

generally above \$0.04 /kWh in 2019, increasing to above \$0.05/kWh in 2028.⁸⁴ The PowerSimm production cost software simulated energy costs in three solar adoption scenarios with or without carbon prices in the Navigant (now Guidehouse Insights) NorthWestern Energy study; the net-metered solar avoided energy costs fell between \$0.029 and 0.03/kWh in 2018.⁸⁵ In New York ISO, the avoided energy costs were \$0.06/kWh in 2015 and 0.07/kWh in 2025 in both targeted and nontargeted scenarios. Crossborder's forecasts of APS's avoided energy costs was a 20-year levelized value of \$0.062/kWh in 2016.⁸⁶ EAI's (Arkansas, MISO) 25-year levelized result was \$0.0635/kWh in 2018.⁸⁷ Maine and Massachusetts, ISO-NE observed slightly higher avoided energy costs in the range of \$0.07–0.08/kWh.⁸⁸

iv. Ancillary services

The impact of DG solar on ancillary services occurs locally. Two categories of ancillary service account for most of the impact of solar PV: operating reserves and voltage control. Solar PV may decrease or increase the need for operating reserves. To illustrate, E3 (Energy and Environmental Economics, Inc.) in its 2013 study assumes that PV reduces net load, which in turn reduces the spinning reserve requirement. But new PV also incurs integration cost associated with new spinning reserves.⁸⁹ DGPV can also beneficially or detrimentally affect local voltage conditions. DGPV installed without reactive power compensation can result in voltage fluctuation. On the other hand, new smart inverters with reactive power control and other features not only compensate for their own potential voltage impacts but also decrease distribution grid voltage-control requirements. The benefits of reactive power controls on distributed solar are significant but hard to quantify. In all U.S. jurisdictions, there is currently no local market or incentives for customers and utility to procure and implement such services below the bulk power system level.⁹⁰

The Maryland VOSS study assessed ancillary services as a relatively minor element of the value of solar with little effect at low solar penetration levels and negligible benefits at higher penetration, with potential system costs. The study thus recommended not including benefits or costs of ancillary services.⁹¹ The E3 New York study assumed that a 1% reduction of total ancillary service costs can be attributed to DGPV. SolarCity found that smart inverters can provide voltage support

⁸⁴ DEA et al., 2018, figures 2 and 3, 4–5

⁸⁵ Navigant Consulting, 2018, 6.

⁸⁶ Beach and McGuire, 2016, 9.

⁸⁷ Beach, R. T., and McGuire, P. G. (2017). *The benefits and costs of net metering solar distributed generation on the system of Entergy Arkansas, Inc.* Berkeley, CA: Crossborder Energy. Retrieved from: http://www.apscservices.info/pdf/16/16-027-R_228_1.pdf, in the Attachment A-1 starting from p. 40

⁸⁸ MPUC (2015). *Maine distributed solar valuation study*. Maine Public Utilities Commission, p. 6. Retrieved from: https://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf; and Acadia Center (2015, April). *Value of distributed generation: Solar PV methodology*, p. 2. Retrieved from: https://acadiacenter.org/wp-content/uploads/2015/04/AcadiaCenter_ValueofDistributedGeneration_StudyMethodology_FINAL_2015_0414.pdf

⁸⁹ E3 (2013, October). *California net energy metering ratepayer impacts evaluation*. San Francisco: Energy and Environmental Economics. Prepared for the California Public Utilities Commission Energy Division.

⁹⁰ NARUC (November 2016). *Distributed energy resources rate design and compensation*. Washington, DC: National Association of Regulatory Utility Commissioners. Retrieved from: <https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0>

⁹¹ DEA et al., 2018, 114.

values as high as \$9,000/kWh.⁹² Navigant decided that NEM solar produces negative benefits for grid support services, but the precise amounts were not quantifiable due to limited data. Also, DGPV incurs negligible integration and interconnection costs according to a NorthWestern Energy service area study. In Maine, solar integration cost was calculated as \$0.005/kWh in 2016 based on results from New England Wind Integration Study.⁹³ Crossborder assumed \$0.002/kWh 25-year levelized solar integration costs in Arkansas based on the conclusions of other solar integration studies.⁹⁴ Finally, the relevant integration cost number cited by APS was \$0.002/kWh in 2020 and \$0.003/kWh in 2030.⁹⁵

v. Reduced RE obligation or RPS costs

DG solar counts toward RPS compliance in many states as a Class I renewable energy resource.⁹⁶ As a result, solar PV does not incur RPS compliance costs. When there is a mechanism to credit in-state solar production to load, solar REC prices can be used as a proxy for avoided RPS compliance costs.

The MD VOSS concluded that the REC benefits for solar in Maryland are quite substantial. In a constrained market, the REC benefit of utility-scale solar could be as high as \$50 per megawatt hour (the alternative compliance price). The REC benefit for BTM solar could reach \$10 per megawatt hour. The Navigant NEM study did not include avoided RPS compliance costs on the rationale that NorthWestern's RPS requirement is projected to be met by existing renewables, new wind energy and carry-over RECs through 2042.⁹⁷

vi. DRIPE effects

Similar to DR, DGPV reduces net system-wide demand for generation when it is generating and can suppress wholesale prices by reducing the clearing price of energy displacing more expensive generation assets. The DRIPE effects accrue to all ratepayers. Several states have counted DRIPE in their value of solar studies including Maine, Massachusetts and Maryland.

In Maine, the estimated DRIPE effect on the energy and capacity markets represented one-fifth of total levelized value of DG solar — as high as \$0.066/kWh in 2016. The MD VOSS calculated energy price reduction benefits using the Aurora model and showed more limited results. Price effects were relatively modest, never exceeding 1.5% of base case prices across zones and scenarios evaluated.⁹⁸

⁹² SolarCity and NRDC (2016). *Distributed energy resources in Nevada*, p. 8, 19. San Mateo, CA/New York: SolarCity/National Resources Defense Council. Retrieved from: https://www.unlv.edu/system/files/file_attachments_private/SolarCity-Distributed_Energy_Resources_in_Nevada.pdf

⁹³ MPUC, 2015, 80.

⁹⁴ Beach and McGuire, 2017.

⁹⁵ TEP IRP team (2014). *2014 integrated resource plan*. Tucson Electric Power Company. Retrieved from: <https://www.tep.com/doc/planning/2014-TEP-IRP.pdf>. Black & Veatch is cited (p. 93 of the plan) for its report: Mason, T., et al. (November 2012). *Solar photovoltaic (PV) integration cost study* (B&V Project No. 174880).

⁹⁶ DEEP (2018). *Connecticut Renewable Portfolio Standard*. Hartford, CT: Department of Energy & Environmental Protection, Public Utilities Regulatory Authority. Retrieved from: <https://www.ct.gov/pura/cwp/view.asp?a=3354&q=415186>

⁹⁷ Navigant Consulting, 2018, 11.

⁹⁸ DEA et al., 2018, 83.

Crossborder assumed that the long-term market price mitigation benefits from solar DG on both gas and electric market prices was approximately \$0.01/kWh in 2016.⁹⁹

b. Values and costs akin to traditional bulk transmission and distribution

i. Avoided transmission and distribution costs

By reducing overall demand, distributed PV can help defer or avoid the need to upgrade transmission and distribution lines. PV resources usually alleviate daytime peak demand, reducing congestion along T&D lines and offsetting the need for T&D infrastructure investments. The DGPV coincidence with system peak means that DG solar even located at the residential circuit can contribute to reduced costs in the distribution system and in the transmission system.¹⁰⁰

In the transmission system, DGPV can relieve the needs to supply load at a location. While some previous studies rely on average avoided transmission costs (e.g., Maine and Massachusetts) or locational wholesale prices (e.g., New York state) to capture this value, other studies use modeling. One approach is to analyze the available data on planned transmission projects using scenario-based production cost modeling where each scenario represents a different network topology/DGPV installation combination. Comparing these results enables a determination of whether avoided transmission enhancements can be attributed to DGPV options. Another method of estimating location value is to co-optimize the transmission expansion and nontransmission alternatives (including DGPV) with a transmission expansion planning model or dedicated power flow model.

In the distribution system, DGPV may decrease or increase distribution system capacity investment. In normal cases, DGPV can reduce or defer the replacement of aging equipment and wires by providing power locally and thereby reducing load over the transmission and distribution systems. In other cases, as solar deployment becomes substantial, upgrades to grid infrastructure may become necessary in order to accommodate large amounts of DGPV. Distribution power flow analysis can be used to estimate the expected capital investment or expansion costs with and without DGPV. Here again, granularity is a challenge. Power flow analysis may encounter computational challenges given the number of data points required and the need to accurately model distribution feeders. As a result, a combination of alternative methods may be used for estimating DGPV distribution capacity impacts, such as deferred investment for peak reduction (e.g., Navigant MT NEM study) and least cost adaptation for higher PV penetration.¹⁰¹

Crossborder Energy found a long-term combined avoided T&D value of \$0.021/kWh (levelized) in the expanded avoided cost scenario of EAI, the Arkansas study.¹⁰² The MD VOSS study undertook an extensive review of the PJM transmission planning process, cost allocation and projects in each

⁹⁹ Beach and McGuire, 2016, 11.

¹⁰⁰ Keyes, J. B., and Rábago, K. R. (2013, October). *A regulator's guidebook: Calculating the benefits and costs of distributed solar generation*. New York: Interstate Renewable Energy Council (IREC). Retrieved from: <https://www.growsolar.org/wp-content/uploads/2014/10/A-Regulators-Guidebook-Calculating-the-Benefits-and-Costs-of-Distributed-Solar-Generation.pdf>

¹⁰¹ Denholm et al., 2014.

¹⁰² Beach and McGuire, 2017.

zone likely to be allocated to Maryland utilities. Based on that review, Daymark Energy concluded that levelized transmission charges savings for Baltimore Gas & Electric's zone to be reduced 3.1% and Delmarva Power & Light's levelized transmission charges to be reduced by 4.4%.¹⁰³ Navigant conducted extensive investigation on-site specific T&D capacity additions that can be deferred by DG solar in NorthWestern Energy's territory. As a result, it assigned a levelized \$0.002/kWh of substation and another \$0.001/kWh of transmission deferral values.¹⁰⁴ E3 developed different scenarios for New York state to better capture the avoided subtransmission and distribution costs, which can be as high as \$0.04/kWh in the targeted scenario in 2025. Acadia Center calculated avoided T&D costs from \$0.04 to \$0.06 per kWh, depending on PV orientation and tile degrees in Massachusetts. Crossborder used National Economic Research Associates (NERA) regression model to calculate APS's avoided T&D costs. Accordingly, avoided transmission costs were \$0.009/kWh for a south-facing system and \$0.016/kWh for a west-facing system; avoided distribution costs fell between \$0.04 and \$0.048/kWh for commercial customers and \$0.015 and \$0.032/kWh for residential customers.¹⁰⁵

ii. Energy and capacity line losses

DGPV system is typically located close to the load. This coincidence of generation with usage enables DGPV to avoid the T&D line losses. The opposite is also theoretically possible for very high levels of solar penetration: where solar generation is considerably greater than local load, the reverse flow of power could result in higher losses.¹⁰⁶ So it is important to properly account for losses when calculating energy and capacity benefits and costs.

Four approaches can be used to estimate T&D losses in increasing order of accuracy and difficulty: average combined loss rate, marginal combined loss rate, locational marginal loss rate and loss rate using power flow models.¹⁰⁷ The loss rate should take spatial and temporal factors into account for DGPV valuation. For example, if DGPV is more correlated with peak loads, its avoided loss rate can be much higher than the average loss rate. The Maine study applied an average T&D losses factor of 6.2% but a higher 9.3% for T&D losses during 100 peak hours. When power flow models are used for quantifying avoided line losses by DGPV, it is a frequent practice to run separate T&D power flow models in recognition of different characteristics of transmission and distribution systems. Navigant derived 4.05% distribution system losses from a CYME-DIST modeling of substations serving various rural and urban circuits and another 4.03% transmission loss based on NorthWestern Montana's Transmission loss study.¹⁰⁸ Crossborder assumed APS's marginal line losses to be 12.1% drawn upon another study looking at the loss impacts of DGPV.¹⁰⁹

¹⁰³ DEA et al., 2018, 109.

¹⁰⁴ Navigant Consulting, 2018, 7–10.

¹⁰⁵ Beach and McGuire, 2016, 13–16.

¹⁰⁶ Delfanti, M., Falabretti, D., and Merlo, M. (2013). *Dispersed generation impact on distribution network losses*. Electric Power Systems Research 97, 10–18.

¹⁰⁷ Denholm et al., 2014.

¹⁰⁸ Navigant Consulting, 2018, 10

¹⁰⁹ Beach and McGuire, 2016, 8.

The MD VOSS loss savings calculated the distribution feeder loss savings alone at 1.7% to 12.1% across all hours based on a detailed distribution system analysis. These losses varied by utility service territory with the more compact and urban having lower loss saving potential and the more rural service territories having the higher end of the loss savings potential.¹¹⁰

iii. Value of resilience

Increasing distributed solar PV decentralizes the grid, potentially safeguarding people in one region from other areas that are experiencing electricity disruptions. Advances in smart inverter technology allow higher percentages of solar energy to be safely integrated into the grid and to increase grid resiliency and reliability.

The MD VOSS study also recognizes the reduced wear and tear on the distribution system from solar, which can reduce system life.

DGPV systems combined with battery storage will further enhance this value. Battery storage can potentially provide power to a portion of a house, and islanding capacity can provide substantial resilience to individual residences or facilitates and even for microgrids. Several studies including the EAI from Crossborder discuss solar DG's reliability and resiliency value as a broad societal benefit; however, Crossborder notes that this value is challenging to quantify.

c. Other customer values and social values

i. Customer values

Customers experience significant bill savings after installing DGPV. In the case with NEM, customers' electricity consumption can be largely or partially offset by its self-generation. As pointed out by E3 in its New York study, NEM is a simple tool to encourage DGPV development that does not typically differentiate temporal and locational grid value. From the customers' perspective, DG solar represents a green option that can be tailored to meet their own needs and/or support communities. PV plus storage or other DERs can serve as backup power to maintain safe operation during a power outage or to power a microgrid.

ii. Economic benefits

The solar energy industry is rapidly growing, creating new jobs and businesses across the nation. In 2015, the solar energy industry added jobs at a rate nearly 12 times that of the overall economy, and now employs more than 208,000 people.¹¹¹ Solar activity also provides additional tax revenue at the state and local levels as installers purchase goods and services. The construction of DGPV often involves local jobs and new technologies, which can generate net benefits on the economic development.

The APS study includes a societal economic benefit of \$0.047/kWh for residential and \$0.029/kWh for commercial solar DG using NREL and LBNL's local soft costs data.¹¹² The Arkansas study found that DGPV contributes incremental benefits of \$0.033/kWh to the local economy, assuming 22% of

¹¹⁰ DEA et al., 2018, 133–134.

¹¹¹ The Solar Foundation (2016, January). *National solar jobs census 2015*. Washington, DC: Solar Foundation.

¹¹² Beach and McGuire, 2016, 21.

residential system costs are spent locally compared to a central power station.¹¹³

iii. Environmental externalities

Solar power provides numerous environmental benefits, including avoided GHG emissions and reduced air pollution. The environmental externalities can be quantified based on the avoided marginal damages of emissions and public health improvement.

The avoided social costs of carbon, SO₂ and NO_x emissions added up to \$0.067/kWh or about one-fourth of estimated value of solar in Massachusetts in 2014.¹¹⁴ The value representing net environmental benefits was \$0.09/kWh in the Maine study in 2016.¹¹⁵ Counting avoided PM_{2.5}, methane leaks and water consumption, the social environmental benefit reached \$0.13/kWh in Arkansas in 2018.¹¹⁶

iv. Hedging value

DGPV has no fuel costs. Because there are no fuel costs, DGPV reduces the variability of future electricity prices to customers due to variable fuel prices. The hedging benefits of PV are certainly greater than zero but difficult to calculate. Some analysts suggest looking at the customers' willingness to pay for mitigating this risk using a hedging surrogate such as the forward contracts for natural gas in places where a gas-fired generator is on the margin most of time.¹¹⁷ In utilities like APS, the hedging costs are a part of a gas procurement strategy. These costs averaged about \$1 per MMBtu, which can be translated to avoided fuel hedging costs of \$0.009/kWh of DG generation.¹¹⁸

The Maine study calculates the avoided fuel price uncertainty as \$0.037/kWh on a 25-year levelized basis using NYMEX futures market prices.¹¹⁹ Crossborder applies the same methodology, generating a fuel hedging value of \$0.028/kWh in the expanded avoided cost scenario. The MD VOSS assesses hedging value as greater than zero but difficult to quantify. For that reason, the Maryland study does not include a quantitative hedging value.¹²⁰ Some of the Maryland parties are critical of not including any value given the recognition that there is a net positive hedging value for solar.

¹¹³ Beach and McGuire, 2017.

¹¹⁴ Acadia Center, 2015, 2. See table: Grid value of solar PV in Massachusetts.

¹¹⁵ MPUC, 2015, 6.

¹¹⁶ Beach and McGuire, 2017.

¹¹⁷ Bolinger, M. (2013, March). *Revisiting the long-term hedge value of wind power in an era of low natural gas prices*. Report No. LBNL-6103E. Berkeley, CA: Lawrence Berkeley National Laboratory. Retrieved from: <https://emp.lbl.gov/sites/default/files/lbnl-6103e.pdf>

¹¹⁸ Beach and McGuire, 2016, 10.

¹¹⁹ MPUC, 2015, 88.

¹²⁰ DEA et al., 2018, 115.

3. Recent value of solar studies

a. Synapse net metering in Mississippi 2014

In December 2010, the Mississippi Public Service Commission opened a docket 2011-AD-2 to investigate developing and implementing net metering and interconnection standards in Mississippi. Synapse conducted a quantitative analysis to estimate the benefits and costs of rooftop solar, which supports the decision making for a potential net-metering policy.¹²¹

The study is aggregated among all utilities and does not individually address costs and benefits for each utility and LSE.¹²² Synapse assumes that 0.5% of historical peak demand can be met by solar installations over the entire study period (2015–2039). To determine the widest range of possible benefits, Synapse designed various sensitivities and scenarios in which selected inputs were used to yield the highest to lowest possible benefits. A list of avoided costs is approximated for several categories under each scenario:

- **Energy:** Net-metered solar rooftop generation displaces oil- and natural-gas-fired units in Mississippi. The avoided energy costs are estimated based on the forecasts of variable operating and fuel costs of the marginal resource. Solar hourly output is derived from NREL's PVWatts calculator.¹²³
- **Capacity:** Synapse uses a simple modeling process to assign the avoided capacity value in each year. The range of values are bounded by MISO south capacity price in low scenario and net cost of new entry (CONE) of a new natural gas combined cycle generator in mid- and high-capacity scenario. The solar capacity credit is assumed to be 58% based on NREL's study.¹²⁴
- **T&D:** In the absence of Mississippi specific utility data, Synapse's in-house database on avoided costs of T&D for over 20 utilities and distribution companies across the country provides the estimated range of values. The average avoided transmission value from this database is \$33 per kW-year, and the average avoided distribution value is \$55 per kW-year.
- **System losses:** To account for variation of line losses, the study uses a load-weighted average of line losses during daylight hours for each T&D system in Mississippi.
- **Environmental compliance:** Synapse develops low to high carbon price forecasts with consideration of pollution abatement costs and latest carbon policies. The middle case forecasts CO₂ price at \$15 per ton in 2020, which increases to \$60 per ton in 2040.

¹²¹ Stanton, E. A., Daniel, J., Vitolo, T., Knight, P., White, D., and Keith, G. (2014, September 19). *Net metering in Mississippi: Costs, benefits and policy considerations*. Synapse Energy Economics. Retrieved from: www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf

¹²² Two vertical integrated utilities (Entergy Mississippi and Mississippi Power), Tennessee Valley Authority (TVA), South Mississippi Electric Power Association and 25 other cooperatives serve the state.

¹²³ NREL PVWatts calculator available at <https://pvwatts.nrel.gov>

¹²⁴ Perez, R., Margolis, R., Kmiecik, M., Schwab, M., and Perez, M. (2006). *Update: Effective load-carrying capability of photovoltaics in the United States*. Kansas City, MO: Midwest Research Institute. Prepared for the National Renewable Energy Laboratory. Retrieved from: <http://www.nrel.gov/docs/fy06osti/40068.pdf>

- Risk: The study applies a 10% avoided risk adder to the avoided costs of solar based on literature review.¹²⁵

The TRC test is chosen to reflect the benefits and costs of the system. As shown in Table 6, the low scenario, where each source of avoided cost is set at the low end of its cost range, is the only one that doesn't pass the TRC test. The study concludes that distributed solar has the potential to put downward pressure on rates because net metering can provide net benefits under almost all the scenarios.

Table 6. TRC Benefit Cost Ratios Under Various Scenarios¹²⁶

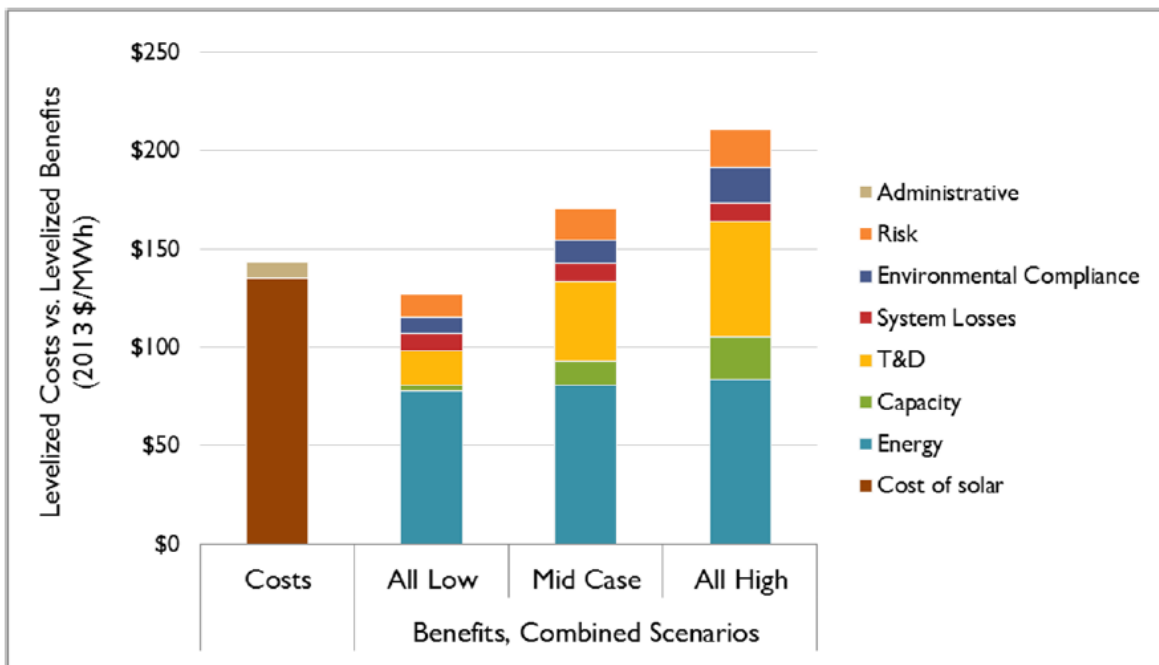
	Low	Mid	High
Fuel Price Scenario	1.17	1.19	1.21
Capacity Value Sensitivities	1.11	1.19	1.26
Avoided T&D Sensitivities	1.01	1.19	1.32
CO ₂ Price Sensitivities	1.16	1.19	1.24
Combined Scenarios	0.89	1.19	1.47

The 25-year levelized utility direct benefits were found to be as high as over \$0.2/kWh in Mississippi. However, Mississippi is not likely to achieve a higher DG solar penetration level if the bill savings of solar rooftop owners can't offset their solar costs. On December 3, 2015, the Mississippi Public Service Commission issued a final order, adopting the Mississippi Renewable Energy Net Metering Rule and Distributed Generation Interconnection Rule.¹²⁷ The rule establishes a renewable energy net-metering rate to compensate net-metered customers for electricity placed on the grid, which is set \$0.025/kWh above the wholesale avoided cost. Qualified low-income customers can receive an additional \$0.02/kWh.

¹²⁵ Stanton et al., 2014, 51–61.

¹²⁶ Stanton et al., 2014, 2.

¹²⁷ Mississippi PUC. Order adopting Net-Metering Rule, Docket No. 2011-AD-2. Filed on December 3, 2015. Retrieved from: https://www.psc.state.ms.us/InsiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=362179

Figure 6. Results of Testing Under Combined Scenarios¹²⁸

b. E3 New York study 2015¹²⁹

E3 performed a study on behalf of New York State Energy and Research Development Authority (NYSERDA) and Department of Public Service (DPS) to analyze the net-metering policy with a focus on evaluating benefits and costs of distributed solar PV — the major technology installed under NEM.

The E3 team used the standard DER valuation framework in the REV (Reforming Energy Vision) proceeding,¹³⁰ which identified potential benefit and cost elements to be included in RIM, PCT and SCT shown in Table 7.

¹²⁸ Stanton et al., 2014, 2.

¹²⁹ E3 (2015, December 11). *The benefits and cost of net energy metering in New York*. San Francisco: Energy and Environmental Economics. Prepared for New York State Energy Research and Development Authority and New York State Department of Public Service. Retrieved from: <https://www.ethree.com/wp-content/uploads/2017/01/E3-NY-Legislative-NEM-Study-Report-121115-FINAL-SENT.pdf>

¹³⁰ State of New York Department of Public Service (2015, July 1). *Staff white paper on benefit and cost analysis in the Reforming Energy Vision proceeding*. Retrieved from: [http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/\\$FILE/Staff_BCA_Whitepaper_Final.pdf](http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/Staff_BCA_Whitepaper_Final.pdf)

Table 7. Benefit and Cost Components of Standard Cost Tests¹³¹

	Benefits	Costs
Participant Cost Test (PCT)	Customer Bill Reductions + State Incentives ⁵² + State Tax Credits/Incentives + Federal Tax Credits	NEM System Costs
Ratepayer Impact Measure (RIM)	Utility Avoided Costs + Market Price Effects	Customer Bill Reductions + State Incentives + Utility Integration Costs + Utility Administration Costs
Societal Cost Test (SCT)*	Utility Avoided Costs + Federal Tax Credits + Societal Benefits + Health Benefits	NEM Generation System Costs + Utility Integration Costs + Utility Administration Costs

The NY REV study approaches each valuation element as follows:

- The value of generation capacity is based on the DPS ICAP model, which forecasts future installed capacity prices.
- The value of energy, including energy losses and compliance costs for criteria pollutants, is derived from a forecast based on production simulation modeling NYISO's CARIS (Congestion Assessment and Resource Integration Study).
- Transmission capacity value is captured in the NYISO CARIS, while subtransmission and distribution capacity values are based on marginal cost of service studies provided by each utility.
- Market price effects can be seen as transfer payment from producers to consumers with no net social benefit improvement. It is, however, included in the RIM test precisely because it benefits all ratepayers.
- Social benefits such as GHG mitigation and air quality improvement are considered in the SCT.
- Other benefits such as RPS value, fuel hedge, net economic impacts and resiliency are not quantified because they are either uncertain, small or outside the scope of the analysis.¹³²

To address the uncertainties with evaluating the benefits and costs of solar DG systems, four scenarios are developed, with high level assumptions described in Table 8.

¹³¹ E3, 2015, 28.

¹³² E3, 2015, 35.

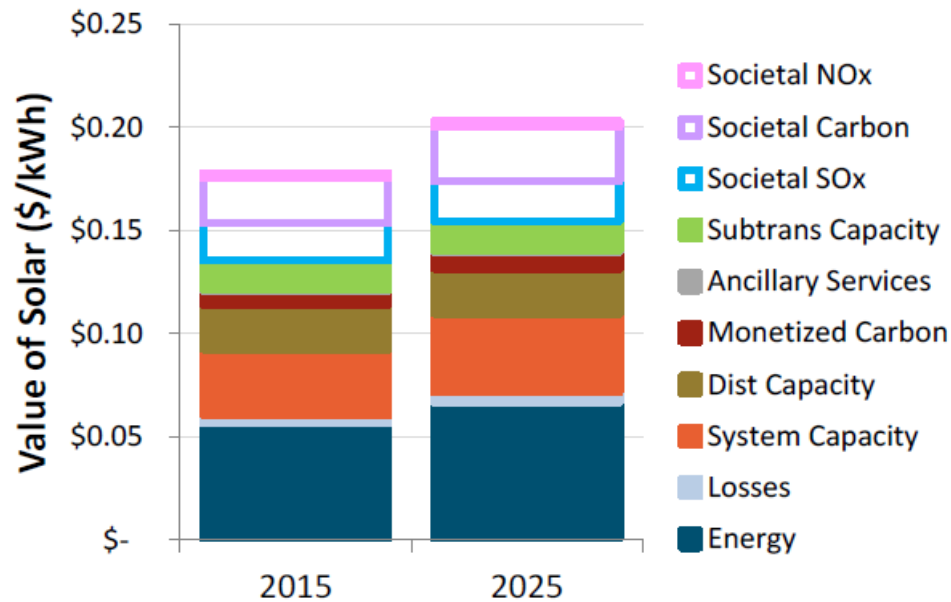
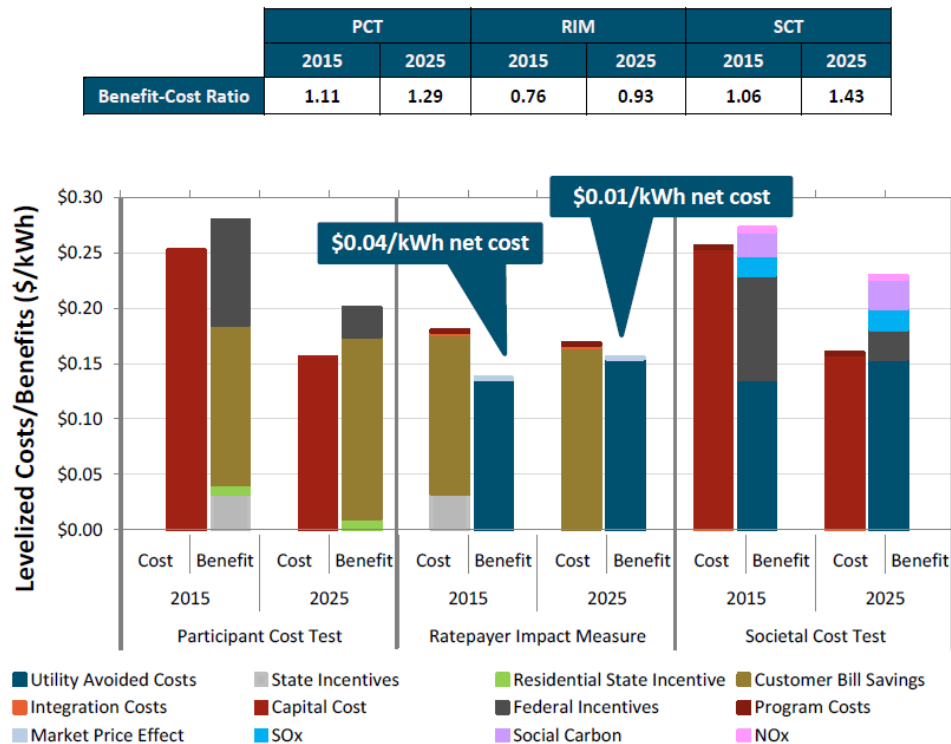
Table 8. NEM Scenarios¹³³

NEM Scenarios	
Lower NEM Value	Untargeted and Expensive Solar, Low Utility Avoided Costs, Less Value for GHG Mitigation and Improved Air Quality, and Higher T&D Delivery Rates
Untargeted NEM (Business as Usual)	'Distribution Value' ⁶⁵ is Under Lock and Key and NEM is Untargeted = Lower Benefits to the Grid
Targeted NEM	'Distribution Value' is Unlocked and NEM is 'Smarter' and Targeted to Maximize Value to the Grid
Higher NEM Value	Better 'Distribution Value' than Expected with 'Smarter' and Cheaper Solar, Higher Utility Avoided Costs, More Value for GHG Mitigation and Improved Air Quality, and Lower T&D Delivery Rates

The resulting New York analysis shows the value of solar in a range between \$0.10 and 0.23 per kWh on a 25-year levelized basis across four scenarios with social benefits counted.

The benefit-cost tests result show that in the targeted NEM and higher NEM value scenarios, there is a net benefit to society, which ranges from 6% to 27%, greater than the costs. In the untargeted NEM scenarios, there is a net social cost in 2015 that turns to a net benefit by 2025. There is also a net participant benefit for these two scenarios. However, using the RIM alone, there is a net cost to ratepayers, as shown in Figure 7. The net benefits are expected to increase over time, according to E3.

¹³³ E3, 2015, 41.

Figure 7. Value of Solar Under Targeted NEM Scenario¹³⁴Figure 8. Levelized Benefits and Costs Comparison for 2015 VS 2025 Under Targeted NEM Scenario¹³⁵¹³⁴ E3, 2015, 43.¹³⁵ E3, 2015, 58.

c. CPR Maine distributed solar valuation study 2015

In 2014, the Maine Legislature enacted a statute to support solar energy development in Maine. Under this law, Clean Power Research (CPR) was asked by the Maine Commission to determine the value of distributed solar energy generation in the state. The results of this study are represented in Figure 9 for Maine's largest utility, Central Maine Power. The general methodology¹³⁶ is similar in some regards to the later Massachusetts study, while several treatments simplify the process and show more representative results than may be obtained in a larger geographical region.

The Maine study builds the valuation elements from a series of detailed elements across different valuation methods where multiple methods are worth considering. For PV fleet production profiles, 15 individual PV systems at each zip code in the state are simulated using CPR's FleetView software, which is weighted by orientation and zip code population and then aggregated to the state level.¹³⁷

For load-match factors, two different effective capacity calculations are made: (1) ELCC for generation capacity is defined as the median of the PV fleet production profile in the peak 100 hours in the ISO-NE area where a capacity value of 54.4% is calculated, and (2) the load match factor for transmission capacity is derived from average monthly reductions in peak transmission demand where a capacity value of 23.9% is found. Two loss savings factors are also calculated: (1) avoided T&D losses for every hour of the load analysis period resulting in an estimated loss of 6.2%, and (2) avoided T&D losses during 100 peak hours in ISO-NE area are calculated yielding an estimated loss of 9.3%.

The Maine study leaves several elements unquantified but worthy of future consideration: avoided natural gas pipeline costs, voltage regulation, and economic development. The avoided distribution capacity cost is not expected to have value because the forecasted peak loads in Maine are flat, so CPR expects that DGPV will have limited opportunity to defer distribution capacity investments.

The value of distributed PV in Maine estimated by CPR is \$ 0.337/kWh, and the breakdown of this value into its components is shown in Figure 9.

¹³⁶ MPUC, 2015, Vol. 1

¹³⁷ There are three utility service territories in Maine: Central Maine Power (CMP), Emera Marine's Bangor Hydro District (BHD) and Maine Public District (MPD).

Figure 9. CMP Distributed Solar Value (in 2016 Dollars)¹³⁸

		Gross Value		Load Match Factor		Loss Savings Factor		Distr. PV Value	
		A	x	B	x	(1+C)	=	D	
25 Year Levelized		(\$/kWh)		(%)		(%)		(\$/kWh)	
Energy Supply	Avoided Energy Cost	\$0.076				6.2%		\$0.081	Avoided Market Costs
	Avoided Gen. Capacity Cost	\$0.068		54.4%		9.3%		\$0.040	
	Avoided Res. Gen. Capacity Cost	\$0.009		54.4%		9.3%		\$0.005	
	Avoided NG Pipeline Cost								
	Solar Integration Cost	(\$0.005)				6.2%		(\$0.005)	
Transmission Delivery Service	Avoided Trans. Capacity Cost	\$0.063		23.9%		9.3%		\$0.016	\$0.138
Distribution Delivery Service	Avoided Dist. Capacity Cost								
Environmental	Voltage Regulation								Societal Benefits \$0.199
	Net Social Cost of Carbon	\$0.020				6.2%		\$0.021	
	Net Social Cost of SO ₂	\$0.058				6.2%		\$0.062	
Other	Net Social Cost of NO _x	\$0.012				6.2%		\$0.013	
	Market Price Response	\$0.062				6.2%		\$0.066	
	Avoided Fuel Price Uncertainty	\$0.035				6.2%		\$0.037	
									\$0.337

d. Acadia Center Massachusetts study 2015

Acadia Center applied a different approach in its value of solar study for Massachusetts. Instead of evaluating accumulated DG solar in the system, it estimated the avoided costs and benefits of six marginal 1 kW solar PV systems: (1) south-facing with a 35 degree tilt from horizontal, (2) south-facing with a 20 degree tilt, (3) west-facing with a 35 degree tilt, (4) west-facing with a 20 degree tilt, (5) west-facing with a 5 degree tilt and (6) a 2-axis tracking system.

The inputs and calculation methods are detailed in its solar PV methodology.¹³⁹ A list of components are added up to form a solar value stack based on grid value and societal value.

Sources of grid value:

- Avoided energy costs: NREL's PVWatts calculator is used to estimate the output of each individual PV system. The average unit cost of avoided energy in 2014 is derived from ISO-NE's hourly day ahead LMP, which is escalated through 2038 featuring EIA's forecasts of natural gas prices and includes annual T&D losses of 11%, a wholesale risk premium of 15% and other ISO-NE costs of 9%.
- Avoided capacity costs: ISO-NE forward capacity market prices are the inputs for its modeling that forecasts capacity prices for the future years through 2038. The avoided capacity value is

¹³⁸ MPUC, 2015, 6.

¹³⁹ Acadia Center, 2015.

discounted to reflect the availability of DGPV based on ISO-NE seasonal claimed capability (SCC) factor.¹⁴⁰

- **Avoided transmission costs:** A 2014 \$89.89/kW-year regional network service (RNS) rate is used and then discounted by an SCC factor. The RNS rate effective on June 1, 2017, is \$111.96/kW-year.¹⁴¹
- **Levelized distribution costs:** These costs are calculated based on inputs from the AESC 2013 study,¹⁴² and then multiplied by a distribution peak coincidence factor unique to each solar PV system to establish the avoided distribution costs.
- **DRIPE:** Both DRIPE energy and capacity values are taken from the AESC 2013 study. The DRIPE energy value is matched with the hourly PV system output profiles.
- **Avoided environmental costs:** The avoided compliance costs of CO₂ are associated with the Global Warming Solution Act targets, or otherwise, RGGI compliance costs. The avoided compliance costs of NO_x are equal to the values outlined in the AESC 2013 study.

Sources of societal value:

- The social cost of CO₂ was \$100 per short ton (2013) and the social costs of SO₂ and NO_x are based on the EPA's guideline.¹⁴³ The compliance costs are subtracted from total avoided social costs to generate net societal values.

As noted by Acadia Center, two important values are not considered in this study: locational values and economic benefits. Therefore, the results from this study may be conservative, and the actual value of distributed solar resources could be larger if DGPV installations are targeted to avoid expensive infrastructural investments.

The Acadia Center study found that the levelized value of solar to the grid ranged from \$0.22 to 0.28/kWh, with additional societal values of \$0.067/kWh in 2014. Figure 10 shows the grid value streams of six DG solar systems in Massachusetts. In general, DG solar provides significant benefits to all, with the value of solar exceeding the average residential retail rate. The study notes that additional policies other than net metering will need to be put into place to encourage west-facing systems for their better performance.

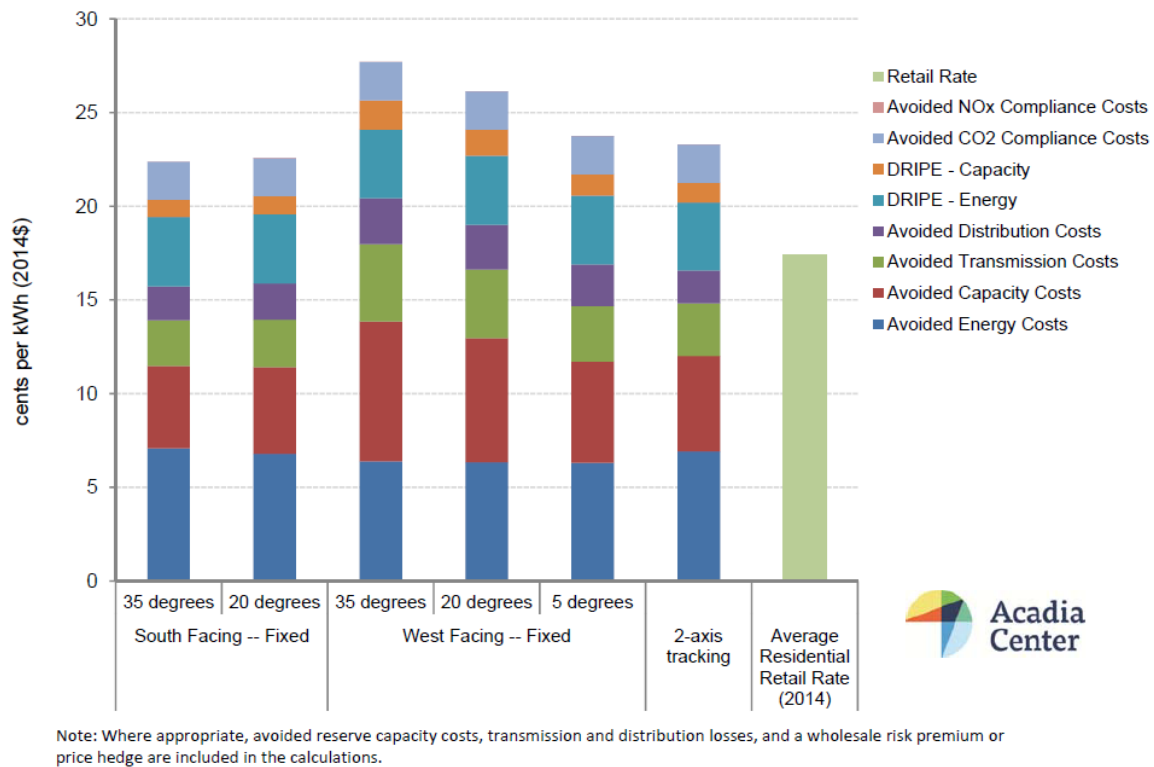
¹⁴⁰ ISO-NE applies SCC factor to solar energy resources that participate in FCMs.

¹⁴¹ Regional rates notice, June 9, 2017. Retrieved from: https://www.iso-ne.com/trans/services/types_apps/ms_through_out_rates.pdf

¹⁴² Hornby et al., 2013.

¹⁴³ U.S. EPA (2014, June). *Regulatory impact analysis for the proposed carbon pollution guidelines for existing power plants and emission standards for modified and reconstructed power plants*. Retrieved from:

<http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf>. See tables 4-7, 4-8 and 4-9.

Figure 10. 25-Year Levelized Grid Value of Solar PV in Massachusetts¹⁴⁴

e. Crossborder Energy, solar DG study for Arizona Public Service, 2016 update¹⁴⁵

In the context of growing solar DG installations, Arizona Corporation Commission initiated a general docket to review the NEM and solar DG valuation issues. The commission ordered Arizona Public Service (APS), the largest electric utility in the state, to provide evidence related to the benefits and costs of solar DG in its service territory. Crossborder Energy contributed to the commission's investigation by presenting a new study building upon its 2013 DG solar study for APS.¹⁴⁶

This study relies on the data from APS's 2014 integrated resource plan (IRP),¹⁴⁷ with supplemental data from other solar DG studies in Arizona and the western United States. As a general approach, Crossborder looks at long-term benefits and costs of DG solar from multiple perspectives, while some unique treatments are highlighted, including:

- A comprehensive list of benefits, including some hard-to-quantify elements, such as fuel hedging, price mitigation, societal environmental and economic benefits; and,

¹⁴⁴ Acadia Center, 2015, 2.

¹⁴⁵ Beach and McGuire, 2016.

¹⁴⁶ Beach and McGuire, 2013.

¹⁴⁷ The APS 2014 IRP is available at <https://www.aps.com/en/ourcompany/ratesregulationsresources/resourceplanning/Pages/resource-planning.aspx>.

- A focus on NEM exports that distinguishes DG solar from other types of DERs. For example, a refined method is adopted to illustrate DG Solar's impact on residential and commercial customers.

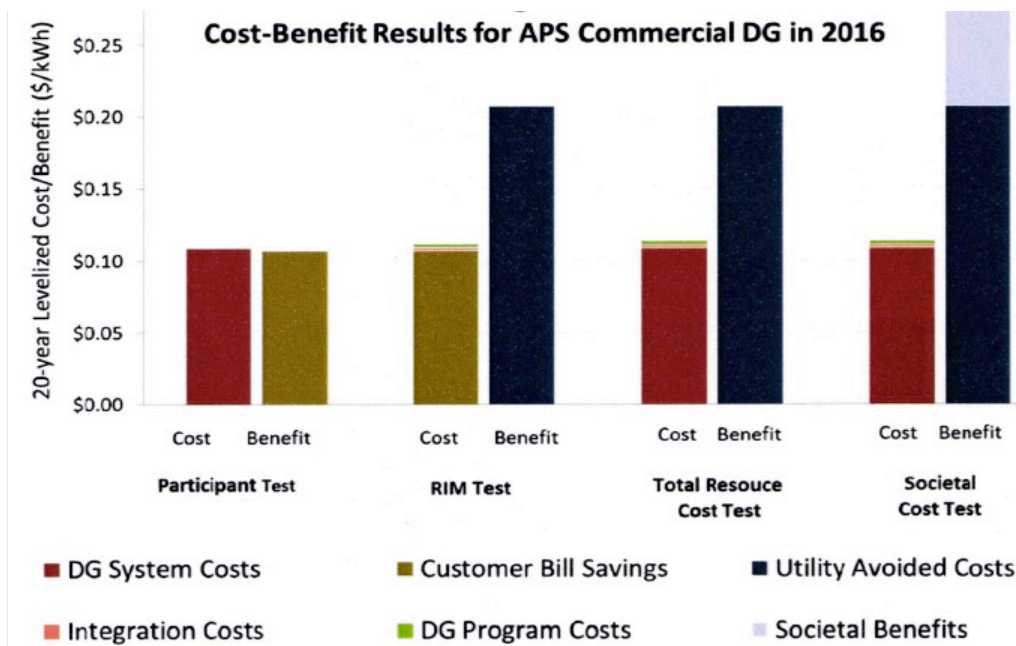
The Crossborder study results are shown in Table 9 and Figure 11.

Table 9. Solar DG Benefits for APS (20-Year Levelized, 2016 Cents/kWh)¹⁴⁸

Avoided Cost	Orientation	Residential	Commercial
Direct			
Energy	All	6.2	6.2
Fuel price hedging	All	0.9	0.9
Market price mitigation	All	1.0	1.0
Capacity	South	5.0	5.0
	West	8.9	8.9
Transmission	South	0.9	0.9
	West	1.6	1.6
Distribution	South	1.5	4.0
	West	3.2	4.8
Total Direct Benefits	South	15.5	18.0
	West	21.8	23.4
	Average	18.7	20.7
Societal			
Carbon	All	3.3	3.3
Criteria Pollutants	All	1.1	1.1
Water	All	0.2	0.2
Local economic benefit	All	4.7	2.9
Total Societal Benefits	All	9.3	7.5
Total Benefits			
Direct and Societal	South	24.8	25.5
	West	31.1	30.9
	Average	28.0	28.2

The study concludes that solar DG is cost effective in the APS service territory because the benefits of solar DG equal or outweigh the costs in both the TRC and SCT methods. The PCT results show that benefits and costs are closely balanced, so careful attention to rate design for residential and commercial customers is recommended. Commercial DG solar benefits largely exceed the costs especially for west-facing systems. The study concludes that encouraging these west-facing DG systems will improve the net benefits to the APS system.

¹⁴⁸ Beach and McGuire, 2016, 22.

Figure 11. Benefit-Cost Test Results for APS Commercial DG in 2016¹⁴⁹

f. SolarCity and NRDC's distributed energy resources in Nevada, 2016¹⁵⁰

This study by a DER provider, SolarCity, and the Natural Resources Defense Council aims to evaluate benefits and costs of distributed energy resources more broadly with a focus on rooftop solar. Building on the E3's earlier 2014 net-metering impacts study,¹⁵¹ which found that benefits closely matched costs in Nevada, the authors updated the assumptions with the latest data and provide a full analysis of costs and benefits based on the existing methodologies for Nevada.

In order to better illustrate the development of DERs, two scenarios were examined in the Nevada study. The first scenario assumes continued deployment of NEM rooftop solar paired with smart inverters, consistent with the revised IEEE 1547-2018 standard in the near term (2017–2019). In the second scenario, new customers are required to adopt a TOU rate as a condition of receiving NEM billing credits. The study assumes that customers will deploy a suite of DERs, including rooftop solar, smart inverters, batteries and load control devices for purposes of the study.

Based on the earlier 2014 study, a calculation from the Nevada Public Tool¹⁵² is used to determine the impact of DGPV for each benefit and cost category using a RIM analysis.

¹⁴⁹ Beach and McGuire, 2016, 2–3.

¹⁵⁰ SolarCity and NRDC, 2016.

¹⁵¹ E3 (2014, July). *Nevada Public Utilities Commission: Nevada net energy metering impacts evaluation*. San Francisco: Energy and Environmental Economics. Prepared for State of Nevada Public Utilities Commission. Retrieved from http://puc.nv.gov/uploadedFiles/pucnv.gov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf

¹⁵² This is a spreadsheet tool developed by E3 in 2014 that incorporates multiple inputs from stakeholders convened by Nevada PUC.

Significant updates to the 2014 E3 assumptions include:

- Annual negative multiplier on the avoided energy cost to reflect natural gas price declines;
- Distribution capacity is quantified in the base scope instead of in the sensitivity case;
- Voltage and power quality support is calculated based on smart inverters' performance in conservation voltage reduction (CVR) programs;¹⁵³
- The social cost of carbon is included as an environmental externality considering the EPA's 2015 social cost of carbon at \$36/metric ton;¹⁵⁴
- A lower escalation rate applies to customer bill savings driven by lower gas price forecasts; and
- Some hard-to-quantify benefits are discussed, including fuel hedging, resiliency, market price suppression and equipment life extension.

Table 10. Annual Benefits of 2017–2019 NEM Solar Rooftop Deployment¹⁵⁵

Type	Benefit and Cost Category	Net Benefits (Excl. Environmental)	Net Benefits + Environmental
<i>2015 Levelized cents/kWh</i>			
Benefits	Energy	3.7	Same
	Line Losses	0.4	Same
	Generation Capacity	2.6	Same
	Ancillary Services	0.1	Same
	Transmission & Distribution Capacity	2.8	Same
	CO ₂ Regulatory Price	0.9	Same
	Voltage Support	0.9	Same
	Criteria Pollutants	Not included	0.1*
	Environmental Externalities	Not included	1.7*
	Total Benefits	11.4	13.2
Costs	Program Costs	0.1	Same
	Integration Costs	0.2	Same
	Participant Bill Savings	9.5	Same
	Total Costs	9.8	9.8
Total Net Benefits		1.6 cents/kWh	3.4 cents/kWh

The benefit-cost analysis shown in Table 10 concludes that rooftop PV under NEM benefits all Nevadan customers with or without environmental benefits included. A levelized net benefit is 3.4 cents/kWh, shown when environmental externalities are included in the first scenario.

NRDC and SolarCity further explore how DER portfolio adoptions can impact the net benefit

¹⁵³ Smart inverters have potential to yield additional 0.4% of energy consumption savings and GHG reductions according to SolarCity.

¹⁵⁴ More recent studies show that the avoided social cost of criteria pollutants can be up to 5 cents/kWh and social carbon cost up to 12 cents/kWh in Nevada.

¹⁵⁵ SolarCity and NRDC, 2016, 11.

of solar PV. The Nevada study does not assign values to each category due to the complex nature of DER technologies and uncertainties on future deployment. Instead, the study provides a qualitative analysis of elements that would be most impacted by the flexible DER resources, including energy storage and demand response. The directional impacts of these changes are summarized in Table 11.

Table 11. Qualitative Impact of Storage and Load Control on Benefits of 2020–2022 NEM Deployments¹⁵⁶

Benefit Category	Directional Impact*	Description
Energy	+	Shifting consumption or generation from low value periods to high value periods increases energy value, which would be done when the spread exceeds the efficiency losses of the energy storage technology.
Line Losses	+	Similar to energy.
Generation Capacity	++	By providing storage capacity or load shift capacity during peak generation periods, the generation capacity value would increase substantially.
Ancillary Services	++	Energy storage and controllable loads provide greater dispatchability than solar and thus could provide ancillary services directly, or be operated in ways to mitigate the need for ancillary services procurement.
Transmission Capacity	++	By providing storage capacity or load shift capacity during peak transmission periods, the transmission capacity value would increase substantially.
Distribution Capacity	++	By providing storage capacity or load shift capacity during peak distribution loading periods, the distribution capacity value would increase substantially.
CO ₂ Regulatory Price	+	By reducing demand during peak periods, less energy production from conventional generation is needed and the associated CO ₂ from fossil fuel combustion is reduced.
Voltage Support	+	Energy storage and load control could provide additional flexibility to manage voltage at the local level, as well as real and reactive power dispatchability to manage voltage.
Criteria Pollutants	+	Similar to CO ₂ Regulatory Price.
Environmental Externalities	+	Similar to CO ₂ Regulatory Price.
Total Benefits	++	The addition of energy storage and load control will materially increase the level of benefits delivered by DER customers.

g. Crossborder Energy Arkansas NEM solar DG study, 2017

The Arkansas Public Service Commission undertook an investigation of net metering, specifically to review the benefits and cost of solar DG, including impacts on ratepayers. Crossborder Energy carried on a study submitted to the Arkansas PSC, examining the economics of DG solar in the service territory of Entergy Arkansas, Inc., (EAI) the largest IOU in the state.¹⁵⁷

The Arkansas study by Crossborder examined the values grouped here by those akin to grid scale generation, those akin to bulk T&D and broader social values.

- For values akin to grid scale generation: DG solar on the EAI system avoids marginal generation in the MISO south market; the hourly day ahead market prices for the Arkansas

¹⁵⁶ SolarCity and NRDC, 2016, 12.

¹⁵⁷ Beach and McGuire, 2017.

Hub are weighted by a standard solar output profile and escalated to calculate avoided energy costs. The DRIPE energy is assumed to be 4% of avoided energy costs or levelized \$0.0028/kWh. MISO has adopted rules to determine the capacity credit, using this methodology; a 54% of nameplate capacity was applied in this study.

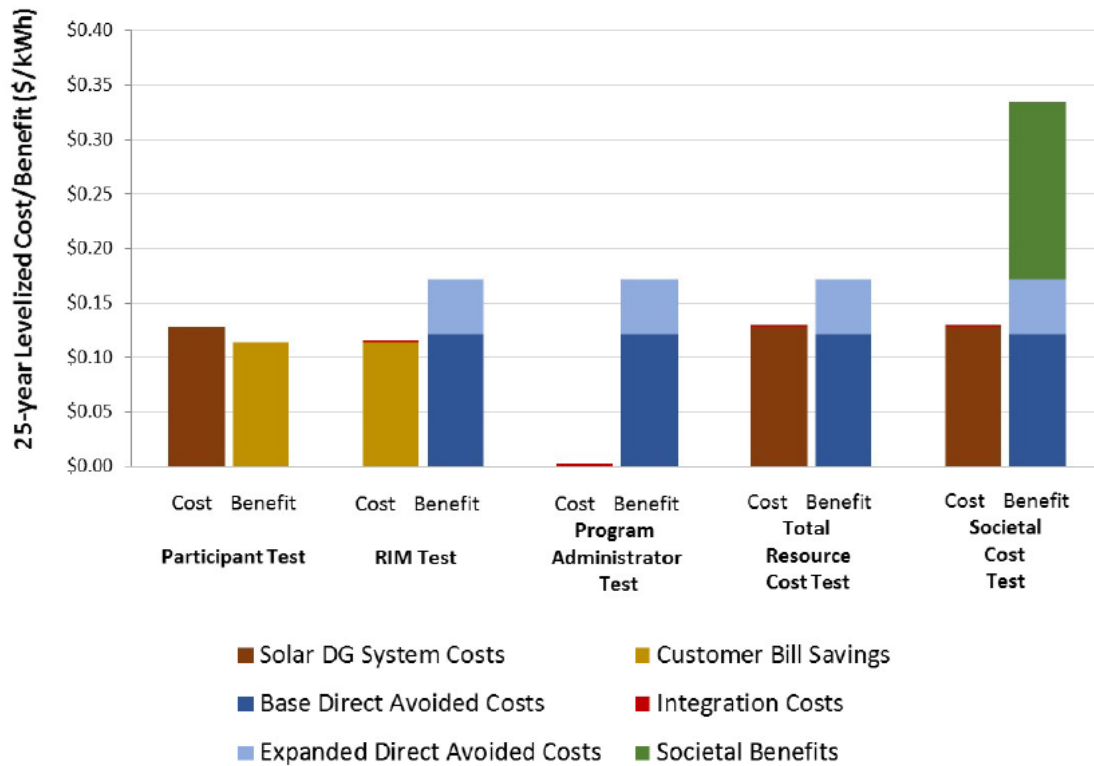
- For values akin to bulk T&D: For avoided T&D costs, two estimates have been made: (1) using a peak capacity allocation factor (PCAF)¹⁵⁸ to adjust avoided T&D costs from energy efficiency assumptions, and (2) using long-term avoided T&D based on National Economic Research Associates' regression method. According to Crossborder, the calculation is conservative at the distribution level for two reasons: First, Crossborder did not have the load data on actual residential class or actual solar output data from the same period. Second, new services and technologies, such as smart inverters, which could potentially avoid distribution capacity, were not considered.
- For broader societal benefits of DGPV: Values are assigned to the social cost of carbon, health benefits of NO_x, SO₂ and PM_{2.5}, water saving and local economic benefit. Those that cannot be quantified with assigned values are assessed qualitatively, including land use, customer choice and resilience value.¹⁵⁹

Direct avoided costs of DG solar in the EAI system are the sum of the first and second value categories, which represent benefits in RIM, PAT and TRC. Expanded direct avoided costs contain more value elements (such as avoided fuel price uncertainty and market price mitigation); for estimating avoided T&D capacity and carbon emissions, a bigger value is considered in the expanded avoided costs scenario. Finally, the social benefits are added to evaluate cost effectiveness in the societal cost test.

Figure 12 shows the cost-effectiveness results for net-metered solar DG on the EAI system in Arkansas. This Arkansas evaluation concludes that net metering does not cause a cost shift to nonparticipating ratepayers and finds that solar DG is cost effective and provides significant societal benefits to all customers in the system.

¹⁵⁸ PCAF shows the contribution of solar capacity to the MISO south peak load, which was estimated to be 52.2% at transmission system and 13.5% at distribution level.

¹⁵⁹ Beach and McGuire, 2017.

Figure 12. Benefits and Costs of Solar DG in Traditional Tests on the EAI System (in 2018 Dollars)¹⁶⁰

h. Navigant NorthWestern Energy MT NEM study, 2018

Montana adopted legislation in April 2017 to review the costs and benefits of solar PV NEM. Navigant (now Guidehouse Insights) was retained by NorthWestern Energy to conduct such a study and submit it to the Montana Public Service Commission. As a part of a general rate case, MPSC will make findings regarding whether to establish rates for net-metered customers.

The Navigant/Guidehouse study¹⁶¹ evaluated customer generators with BTM solar PV up to 50 kW in NorthWestern's service territory. Three scenarios featuring low to high solar PV adoption level and two CO₂ price scenarios were developed. The results are shown in Figures 13 and 14 with a 25-year levelized net avoided costs ranges of \$0.035 to \$0.046/kWh. The highest value is in the low solar penetration with the CO₂ price scenario. Applying the RIM test, with reduced revenue considered a cost, Navigant found that the reduced revenue outweighs the benefits of NEM solar across its scenarios.

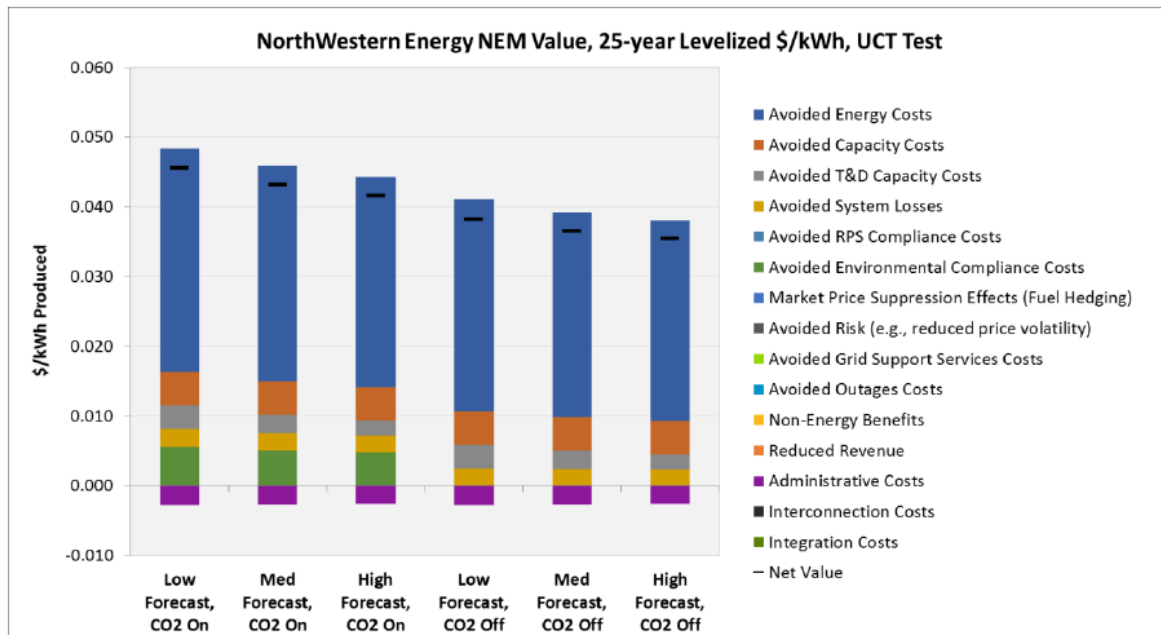
After this analysis was released to the public, various stakeholders, including Montana Environmental Information Center and Montana Renewable Energy Association, were critical, stating that "the Navigant study does not include adequate data on its assumptions and modeling

¹⁶⁰ Beach and McGuire, 2017.

¹⁶¹ Navigant Consulting, 2018.

to verify its claims.”¹⁶² During the July Energy and Telecommunication Interim Committee meeting, the committee members, as well as Montana PSC, requested additional information and materials used by Navigant. The underlying data is expected to be filed by the end of September 2019 for the rate case. Transparency may remain a concern for certain proprietary information.¹⁶³

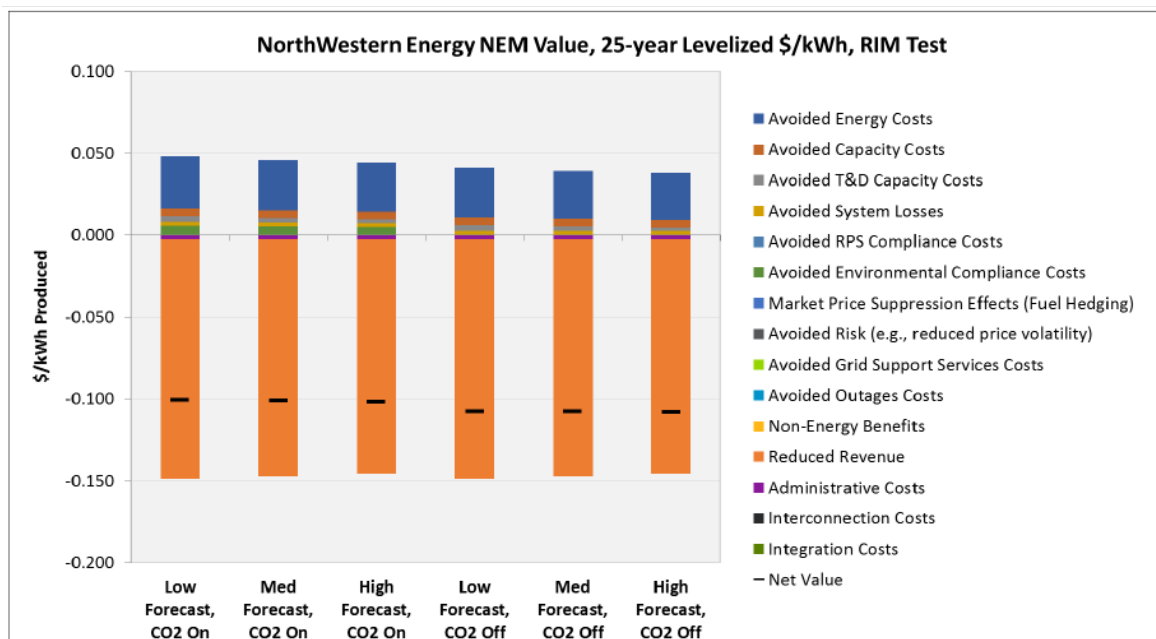
Figure 13. Levelized Net Avoided Costs for the UCT Test (in 2018 Dollars)¹⁶⁴



¹⁶² Trabish, H. K. (2018, May 10). *How two value-of-solar studies add up to no clear value of solar*. Deep Dive, Utility Dive. Retrieved from: <https://www.utilitydive.com/news/how-two-value-of-solar-studies-add-up-to-no-clear-value-of-solar/522892/>

¹⁶³ 65th Montana Legislature: Energy and Telecommunication Interim Committee meeting. Retrieved from: <https://leg.mt.gov/content/Committees/Interim/2017-2018/Energy-and-Telecommunications/Meetings/Sept-2018/TAB%205%20-%20NET%20METER%20MEMO.pdf>

¹⁶⁴ Navigant Consulting, 2018, 19.

Figure 14. Net Avoided Costs in RIM test (in 2018 Dollars)¹⁶⁵

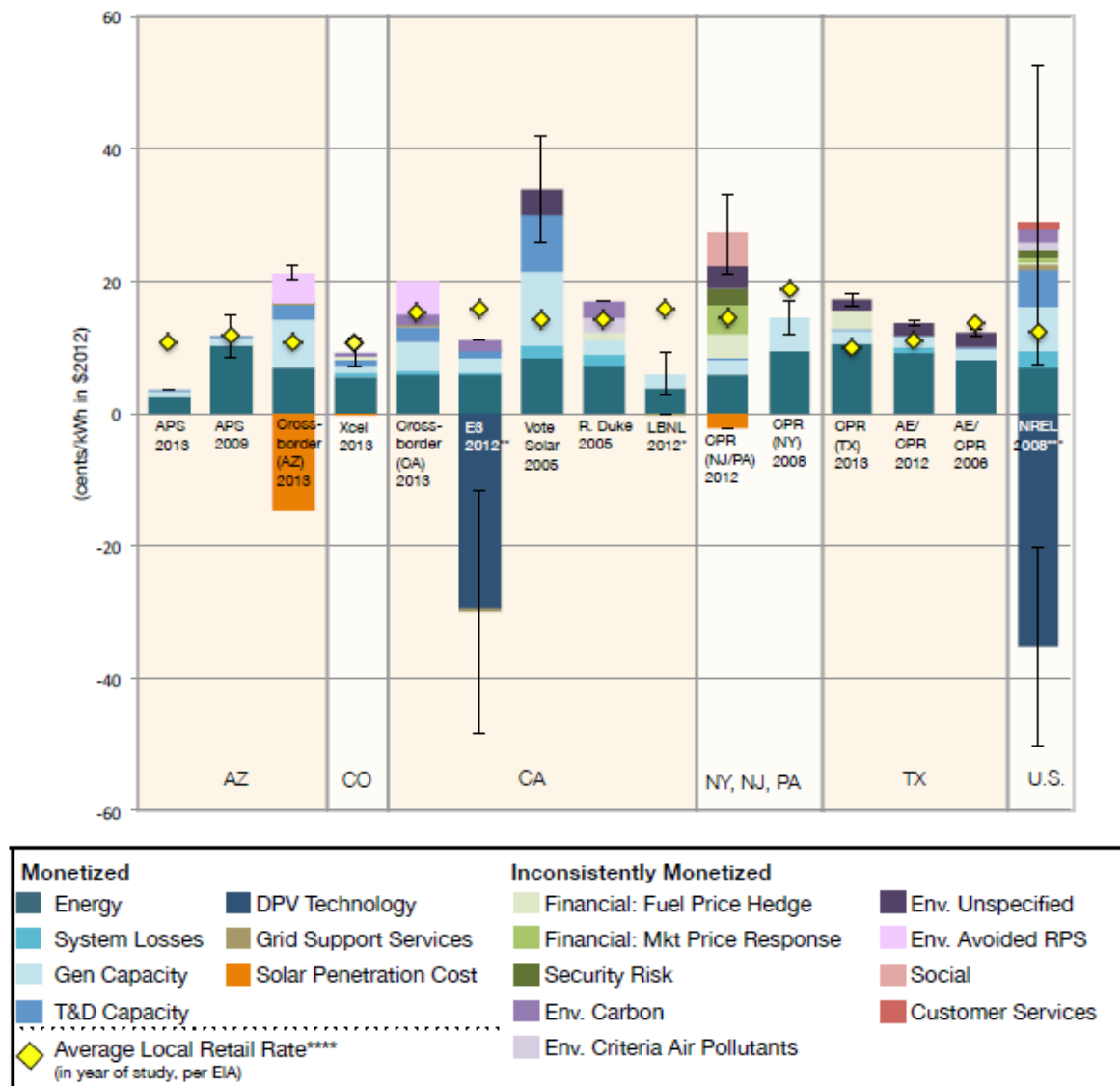
4. Meta analyses on solar value

This section provides a bird's-eye view by surveying the value of solar meta analyses. To reiterate, there is considerable variability in approaches, methodologies, assumptions and quantitative tools used in rating the value of solar studies. These analytic efforts have been made to compare VOSS studies and address gaps of understanding.

RMI reviewed 16 DGPV benefit-cost studies completed by utilities, national labs and other organizations between 2005 and 2013. RMI concludes that although many studies agree on the broad categories of values and costs, no study comprehensively evaluates the benefits and costs of DGPV. The range of estimated value is significant across these 16 studies driven by local context but also the inconsistency of methodology and inputs, especially for hard-to-monetize values, such as real hedging value, market price response, security risk and environmental and social values. RMI provides an overview of key components for each study at the end of its report.¹⁶⁶

¹⁶⁵ Navigant Consulting, 2018, 21.

¹⁶⁶ RMI, 2013. See pp. 44–59 for details of overview; list of studies reviewed is on p. 61.

Figure 15. Benefits and Costs of Distributed PV by Study¹⁶⁷

In the RMI paper, a further discussion on some contentious value elements shows the complexity of DG solar valuation.¹⁶⁸

¹⁶⁷ RMI, 2013, 22.

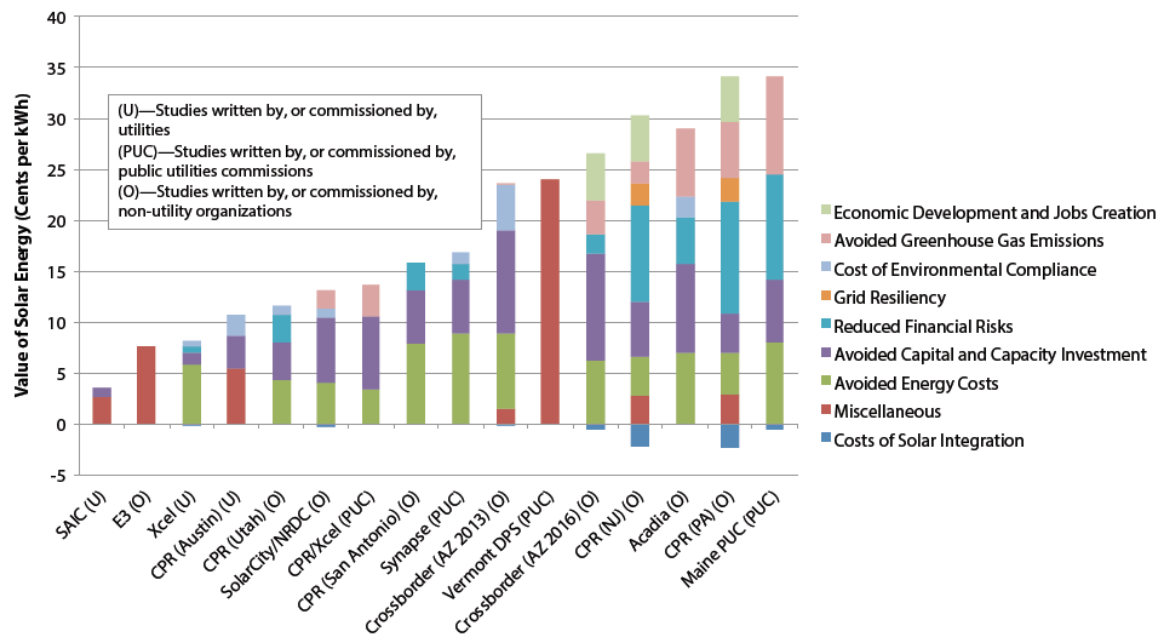
¹⁶⁸ RMI, 2013, 29–32, 35, 36.

SIDEBAR

- **Generation capacity:** The ability of solar DG to defer or avoid conventional units depends on two main factors: the effective capacity of solar DG and the system capacity needed. The effective capacity of DGPV, which looks at solar resource profile and its relation to the system, is usually calculated based on the ELCC method. Most studies assume that a gas combustion turbine, or occasionally a gas combined cycle, to be a marginal resource, while others rely on market price to assess the capacity value. In ISOs with energy-only markets, capacity value can be reflected as a part of the energy price and thus needs a different approach, such as net capacity cost (e.g., California E3 2012). Finally, different treatments have been used concerning whether minimum DGPV is required to defer capacity. Some studies (e.g., Crossborder (AZ) 2013) credit every unit of effective DPV capacity with capacity value, whereas others (e.g., APS 2009) require a certain minimum amount of solar be installed to defer an actual planned resource before capacity value is credited.
- In the long run, generation capacity is likely to change because in a system with high penetration of DG solar, the daily peak (net load) would be pushed to later in the day when the sun is not shining. DGPV would also displace less expensive generation after the penetration reaches a certain level.
- **Transmission and distribution capacity:** The net value of deferring or avoiding T&D investments is driven by rate of load growth, DGPV configuration and energy production, peak coincidence and effective capacity, which can lead to a wide range of calculation results. Studies typically determine the T&D capacity value based on the capital costs of planned expansion projects in the region of interest. However, the granularity of analysis differs across service territories, from project to project. The system context is particularly important for these reasons: (1) Locational characteristics, such as site-specific age and usage, determine the costs and needs for infrastructural upgrades or expansions. (2) The PV capacity and its coincidence with peak at transmission and distribution level. RMI points out that the distribution system usually requires more geographically specific data that reflects the site specific characteristics, such as local hourly PV production and correlation with local load. (3) T&D investment plan and projected load growth. (4) The length of time the investment is deferred. Some questions remain unanswered for how to estimate DGPV's T&D capacity value in the face of "lumpy" T&D investment and what standard of effective capacity should be used in a specific deferring project — ELCC or a certain confidence level. For example, a 90% confidence level was used to determine DG solar's ability to defer a distribution project in the APS 2009 and 2013 studies.
- **Fuel price hedge:** Most studies agree that solar DG can hedge against the fuel price volatility and the risk to utilities and customers. The difficulty in quantifying this value lies on the marginal resource characteristics and exposure to fuel price volatility. NYMEX futures market price provides natural gas forecasts, which has adequate reflection of volatility for 12 years. Beyond that, different approaches are in use either escalating NYMEX prices at a constant rate (Crossborder (AZ) 2013), or estimating the volatility hedge value separately as the value of an option/swap, or as the actual price added the utility is incurring now to hedge gas prices (CPR (NJ/PA) 2012), NREL 2008).
- **Market price response:** As the other demand side resources that increase efficiency and decrease consumption, DG solar can have the effect of bringing down the market price, especially at a higher penetration, by reshaping the demand curve and reducing the needs for expensive marginal generator. However, its subsequent market impact has to be studied further to precisely estimate this value. As energy prices decline, which could result in higher demand, these benefits could potentially be reduced in the longer term (E3 2012). Additionally, depressed prices in the energy market could have a feedback effect by raising capacity price. (CPR (NJ/PA) 2012).

Environment America Research & Policy Center and Frontier Group reviewed 16 value of solar studies published from 2012 to 2016 across jurisdictions in the United States.¹⁶⁹ Nearly all of these 16 studies find that solar energy brings net benefits to the grid and to society. Three-quarters of the 16 studies show the value of DG solar exceeds local average retail residential electricity rates; this finding indicates that net metering does not fairly compensate solar DER owners. Another observation of this report is that utility-conducted studies have a tendency to under evaluate solar by focusing on the direct avoided costs, while excluding or underestimating benefits accruing to the environment and society, compared to studies by PUCs and others.

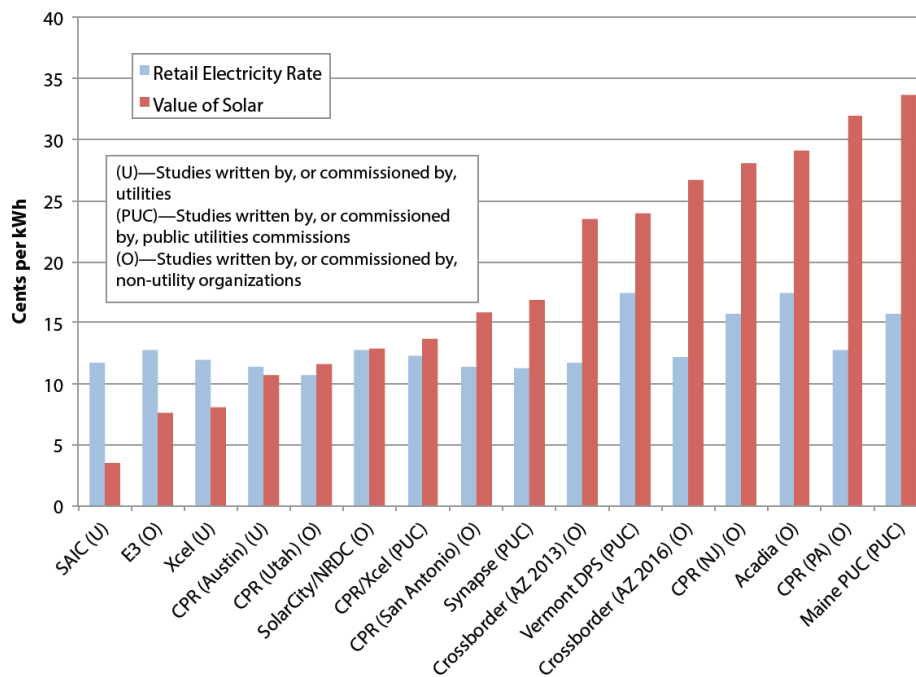
Figure 16. Comparison of Solar Energy Benefit-Cost Analyses by Report and Category¹⁷⁰



¹⁶⁹ Weissman, G., and Fanshaw, B. (2016, October). *Shining rewards: The value of rooftop solar power for consumers and society*. Frontier Group, Environment America Research & Policy Center. Retrieved from:

<https://environmentamerica.org/sites/environment/files/reports/AME%20ShiningRewards%20Rpt%20Oct16%201.1.pdf>

¹⁷⁰ Weissman and Fanshaw, 2016, 14.

Figure 17. Average Retail Residential Rates Compared to the Values of Solar in 16 Benefit-Cost Analyses¹⁷¹

ICF reviewed the most recently published benefit-cost studies related to NEM and distributed solar from 15 states.¹⁷² This meta-analysis finds an evolution of approaches to account for the temporal and locational value of distributed solar with specific characteristics. States have considered broader valuation studies and frameworks to fully examine the benefits and costs of distributed solar PV and other DERs. For better analyzing these studies, ICF grouped them into three categories: NEM cost-benefit analysis, VOS/NEM successor studies, and DER value frameworks.

Table 12 below contains the description of study type and the studies in each category.

¹⁷¹ Weissman and Fanshaw, 2016, 15.

¹⁷² ICF (2018, May). *Review of recent cost benefit studies related to net metering and distributed solar*. Prepared for the U.S. Department of Energy. Retrieved from: https://www.icf.com/-/media/files/icf/reports/2019/icf-nem-meta-analysis_formatted-final_revised-1-17-193.pdf?la=en&hash=1E4AD2DDBCE6B6D8ACC98A1182312E8FCF183D3F

Table 12. Grouping of Study Types¹⁷³

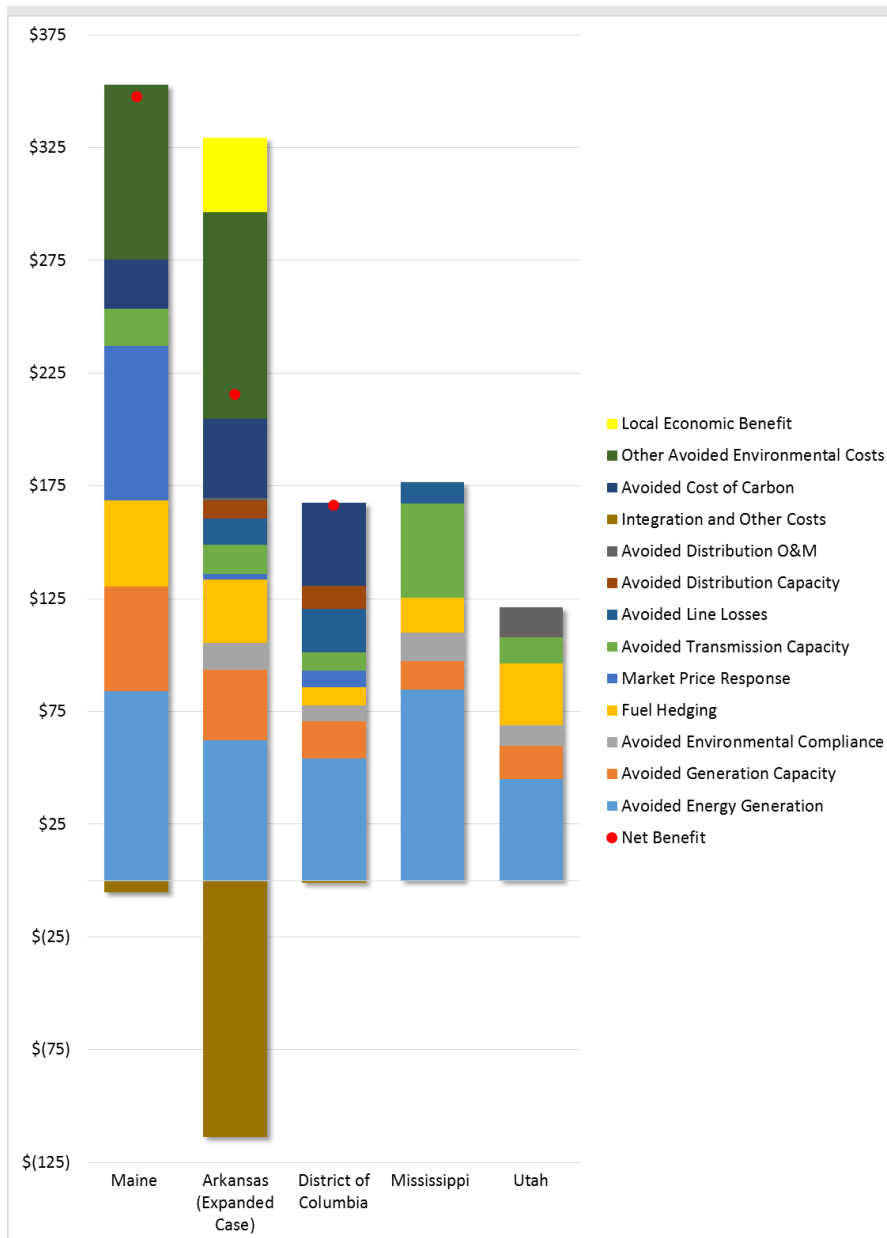
Type of Study	Number Reviewed	Description of Study Type	States/Prepared by
NEM Cost-Benefit Analysis	6	Evaluate costs and benefits of a NEM program; study whether NEM is creating a cost-shift to nonparticipating ratepayers.	<ul style="list-style-type: none"> Arkansas (Crossborder) Louisiana (Acadian) Mississippi (Synapse) Nevada (E3) South Carolina (E3) Vermont (VT PSD)
VOS/NEM Successor	7	Discuss the impacts of NEM and consider options for reforming or realigning rates with the net impacts of distributed solar in ways that go beyond net metering.	<ul style="list-style-type: none"> District of Columbia (Synapse) Georgia (Southern Company) Hawaii (CPR) Maine (CPR) Minnesota (CPR) Oregon (CPR) Utah (CPR)
DER Value Frameworks	2	Reflect the elements of regulatory activities that look at VOS as part of a more precise approach within a framework that can be applied to other DERs.	<ul style="list-style-type: none"> California LNBA (CPUC) New York BCA (Department of Public Service Staff)

Because the scope and objectives are different from one to another category of studies, the outcomes are varied. The perspectives from which the costs and benefits are evaluated, what and how value streams are quantified, regional differences and input assumptions¹⁷⁴ are some of the key variables that affect the results of VOS/NEM studies. Figure 18 compares the value stacks from the 15 selected studies analyzed in the paper. Of the six NEM studies, Louisiana and Nevada conclude that costs exceed overall benefits; South Carolina and Vermont found that NEM-related cost-shifting is de minimus or “close to zero.” The other VOS studies and DER frameworks provide a methodology but do not produce a specific quantified value estimate.

ICF finds that the most common value components are at the bulk system level: avoided energy, avoided generation capacity and avoided transmission capacity which are easier to quantify using existing methods and models. Other value components, such as avoided distribution O&M, reliability /resiliency, and economic development, require more complex quantification given more less common quantification methods for these benefits and costs categories. California and New York are moving in the direction of examining whether a more standardized DER valuation frame is possible.

¹⁷³ ICF, 2018, 7.

¹⁷⁴ ICF discussed how widely used assumptions such as marginal unit displacement, solar penetration, integration costs, externalities, and discount rates can drive the difference of findings. For more details, see pp. 25-30.

Figure 18. Comparison of Value Stacks¹⁷⁵

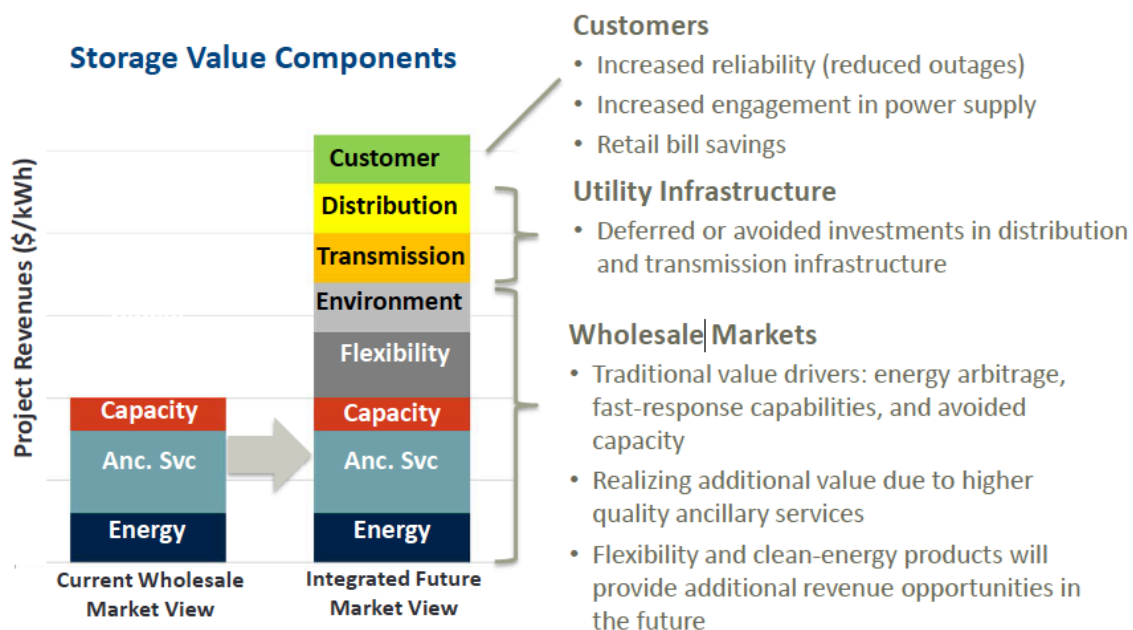
¹⁷⁵ ICF, 2018, 22. Values expressed in 2017 dollars per kWh, levelized over 25 years (except for the District of Columbia, which used 24 years). Studies that expressed values in varying dollar years and in dollars per kWh were converted. The Arkansas study looked at two sets of avoided costs, including an "expanded case," which includes a broader set of categories and is shown here. The District of Columbia's cost categories are included but are not visible because the value is small. The Mississippi study considered two cost categories (reduced revenue and administrative costs), but neither value is shown because the detailed data were not found in the study. Utah did not include separate cost categories. Louisiana is not represented in the figure because costs and benefits are presented in net present value terms and do not lend themselves to comparison.

Appendix C: Distributed Battery Storage

1. Background

Energy storage systems, which include battery storage, have typically been configured to support one or more specific use cases, applications or revenue streams. Storage can look like a demand-reducing resource, sometimes like generation and even sometimes like a transmission or distribution resource, depending entirely on how it is deployed and used. Use cases for storage include: displacing high-cost power (either behind-the-meter at a customer premises or by grid operators to reduce dispatch of peaking generation); infrastructure deferral by avoiding or delaying generation, transmission or distribution upgrades; ancillary services to ensure power quality (frequency and voltage regulation) and reliability (spinning and non-spinning reserves); and firming up renewable energy by absorbing excess production and supplying it to the grid during an interruption. Figure 19 illustrates the more extensive values that storage provides, compared to the current wholesale supply market values.

Figure 19. Storage Value Components¹⁷⁶



Storage is unique in that it can provide a wide variety of functional uses and thus benefits, but what benefits are realized depend on how the storage device is operated and for what purposes. Most battery storage devices are utilized for a primary purpose, such as providing distribution upgrade deferral or customer demand charge reduction. The device must be available to provide this primary service, which will impact the types and durations of any other services that the same

¹⁷⁶ Chang, J., Pfeifenberger, J., Ruiz, P., and Bishop, H. (April 2018). *Getting to 50 GW?: The role of FERC Order 841, RTOs, states, and utilities in unlocking storage's potential*. Cambridge, MA: The Brattle Group. Retrieved from <http://www.brattle.com/news-and-knowledge/publications/getting-to-50-gw-the-role-of-ferc-order-841-rtos-states-and-utilities-in-unlocking-storages-potential>

storage device can provide. Some secondary uses may be complementary to a primary service, but it is also possible that the operating requirements of a specific primary use case may preclude efficient economic operations of another use case for the same system.¹⁷⁷ There will be tradeoffs between pursuing different value streams and combinations of primary, secondary and tertiary uses.

The value that storage can provide depends on the market rules in a given jurisdiction. Regional wholesale markets have different rules for how distributed energy resources like storage can offer services and whether they can participate in certain markets at all. This means the owner or operator of an energy storage system might not be able to access or optimize all the potential benefits of the system. At a project level, the lack of rules on multiple DER uses can negatively affect the economics of the project. At the system level, the lack of rules on multiple DER uses may leave economic value unrealized and reliability potential untapped.

In February 2018, FERC issued Order 841, which directed wholesale market operators to address market barriers for storage to help it compete on a level playing field with other technologies. (This order is discussed in more detail below.) Following this order, The Brattle Group released a study¹⁷⁸ estimating that “at least half of the total value that storage can provide would be achievable in wholesale electricity markets, with the remainder accruing at the transmission and distribution (T&D) and customer level.” Indeed, many analyses have shown that to fully realize the value of storage, benefits related to reduced T&D costs and customer benefits, such as bill savings, need to be captured. The 2018 Brattle study estimated that combining the benefits enabled by the FERC decision with utility (T&D) and customer values would likely increase the market potential for storage by three to five times, compared to a future that limits storage to capturing only wholesale market benefits.

In this section, we first describe two wholesale market approaches to storage participation, then some different approaches to valuing the benefits of storage and finally discuss how the layer cake of potential benefits could apply in New England.

a. Wholesale market approaches to storage participation

i. FERC

Order 841 directs operators of wholesale markets — regional transmission organizations (RTOs) and independent system operators (ISOs) — to develop market rules for energy storage to participate in the wholesale energy, capacity and ancillary services markets that recognize the physical and operational characteristics of the resource.

FERC specifies that those rules must:

- Ensure that a storage resource can provide all the services it is technically capable of providing;
- Ensure that an energy storage resource can be dispatched and can set market clearing prices as both a buyer and a seller;

¹⁷⁷ Lazard (2017, November). *Lazard's levelized cost of storage analysis: Version 3.0*. Hamilton, Bermuda: Lazard. Retrieved from: <https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf>

¹⁷⁸ Chang et al., 2018.

- Account for the physical and operational characteristics of storage resources through bidding parameters or other means;
- Establish a minimum size for participation in RTO/ISO markets that does not exceed 100 kW; and
- Specify that the sale of electricity from the RTO/ISO markets to a storage resource that the resource resells must be at the wholesale locational marginal price.

The ISOs and RTOs submitted their compliance filings for Order 841 in early December 2018. FERC, grid operators and stakeholders have until December 3, 2019, to review, revise and implement the plans according to the timeline set by FERC when it issued Order 841 in February 2018. The compliance filings reveal that storage resources will face tougher requirements in some regions than others. For example, storage-offering capacity would have to continuously supply energy for two hours in ISO-NE, four hours in NYISO and 10 hours in PJM. The compliance filings of CAISO and ISO-NE are discussed briefly below.

ii. CAISO

The California Independent System Operator (CAISO) has been making enhancements to its wholesale energy and ancillary services markets to address storage participation. Through its Energy Storage and Distributed Energy Resources stakeholder groups, CAISO is working to grow market participation of grid-connected storage.

CAISO's NGR (non-generator resource) participation model is specifically designed for storage or storage-like resources — i.e., resources capable of rapidly shifting between injecting into or withdrawing energy from the grid — including distribution-level storage. NGRs are treated in some ways like traditional generators and in some ways like traditional DR load curtailment resources, which participate in the CAISO markets as proxy demand resources or PDRs. Although NGRs can offer to reduce load and be compensated for that, just as PDRs can, NGRs are also able to inject energy into the grid and earn revenue by providing a wide range of services to CAISO, including energy, reserves and regulation services in the day-ahead, real-time and ancillary service markets. NGRs (whether participating individually or in aggregations) are also like traditional generators in that they are visible to and accessible for direct communication with the ISO as distinct resources (as opposed to PDRs, which, from the ISO point of view, just affect net load). Accordingly, NGRs do not need to rely on baselines to measure performance.

The NGR participation model appears to be consistent with FERC's recent Order 841 even though it predates that order. It allows a resource to:

- Provide all services it is capable of providing;
- Be dispatched;
- Account for the physical and operational characteristics of electric storage resources;
- Have a minimum size threshold below 100 kW; and
- Resell energy back to the wholesale market at the wholesale locational marginal price.

CAISO's 841 compliance filing proposes very few changes to existing market structures and rules and essentially asserts that CAISO is in compliance with the FERC order.¹⁷⁹ The CAISO did note that its existing rules require all participating generators to have a minimum capacity of 500 kW. To bring these rules into compliance with Order 841, CAISO proposes to revise this requirement such that storage resources must have a minimum capacity of 100kW to qualify as participating generators.

iii. ISO-NE

Multiple studies on the value of storage in varied states and wholesale markets point to the importance of revenue mechanisms to be in place to capture the potential benefits to justify an investment in storage. In general, analyses show that if only a subset of revenue streams are accessible (e.g., only T&D values to a distribution utility), the result will be an underinvestment and underutilization of energy storage on a system-wide basis, leaving value untapped.

Historically, ISO-NE required storage resources to participate in its markets as two separate assets, one acting as load and another acting as generation. This fails to recognize that battery storage systems can respond immediately to dispatch signals, shifting between load and generation. In February 2019, FERC approved rule changes proposed by ISO-NE, broadening storage resources' ability to provide services in all three of ISO-NE's markets. The new tariff section adds a definition of storage called continuous storage facilities, which can transition between charging and discharging as well as provide regulation services.

Under ISO-NE's Order 841 filing, storage-offering capacity would have to continuously supply energy for two hours. ISO-NE also lowered the minimum size threshold for the various participation model options (generator assets, dispatchable asset related demand and alternative technology regulation resource) associated with electric storage facilities from 1 MW to 100 kW to be in compliance with the FERC order. ISO-NE proposed some other changes that will be less beneficial for storage participation in markets, including calling for automatic derating of energy storage resources every five minutes to ensure the resources have enough charge to meet ISO needs. This removes some control from storage operators to flexibly bid their resources into the market economically. Additionally, ISO-NE was the only ISO to propose that energy storage would need to register as a generation resource, which could limit the flexibility of storage participation in markets.

¹⁷⁹ California ISO (2018, December 3). Compliance with Order No. 841. California Independent System Operator Corporation (Docket No. ER19-__-000). Retrieved from: <http://www.caiso.com/Documents/Dec3-2018-Compliance-OrderNo841-ElectricStorageParticipation-ER19-468.pdf>

b. Examples of approaches to valuing benefits of storage

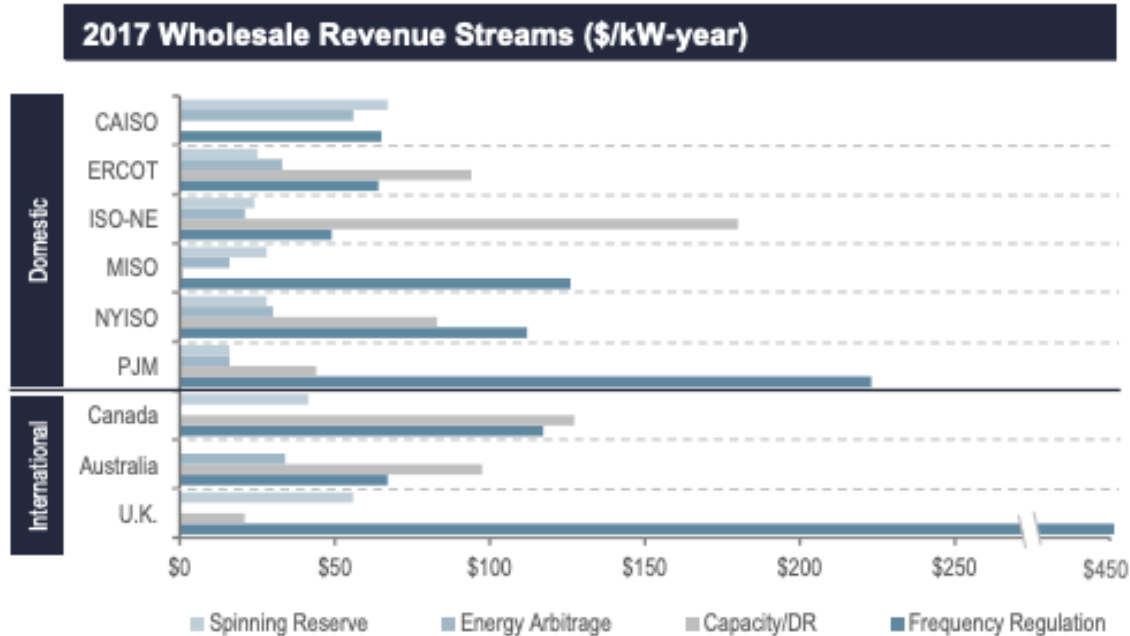
i. Lazard analysis of wholesale market revenue streams¹⁸⁰

Lazard's levelized cost of storage analysis (version 4.0) included an estimate of currently identifiable sources of revenue for energy storage projects. The wholesale revenues included in the analysis are:

- Demand response: managing high wholesale prices or emergency conditions.
- Energy arbitrage: storage of inexpensive electricity to sell at a higher price later.
- Frequency regulation: immediate power to maintain generation-load balance.
- Resource adequacy: capacity to meet generation requirements at peak load in a region with limited generation or transmission capacity.
- Spin/non-spin reserve: maintain electricity output during unexpected contingency event immediately (spin) or on short notice (non-spin).

Lazard identified technical factors that impact the availability of these revenue streams, including the minimum size to qualify as a generator and whether limitations are placed on storage assets when they are qualifying for the wholesale market. Figure 20 shows the wholesale revenue streams from 2017 for storage.

Figure 20. 2017 Wholesale Revenue Streams¹⁸¹



¹⁸⁰ Lazard (2018, November). *Lazard's levelized cost of storage analysis: Version 4.0*. Hamilton, Bermuda: Lazard. Retrieved from:

<https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf>

¹⁸¹ Lazard, 2018, 18.

ii. California's multiple use applications of storage docket

California is advancing efforts to promote adoption of energy storage and enable capture of multiple value streams. In early 2018, the CPUC issued a decision¹⁸² for new multiple-use applications for storage, allowing providers to stack various services. The CPUC recognizes that current market constructs can act as barriers for storage realizing much of its economic value to the system. The CPUC decision adopted 11 interim rules outlining how multiple-use applications should be evaluated and established a working group to develop recommendations for how storage could access multiple value streams.

The CPUC decision recognizes that the potential value streams of storage depend upon where the system is interconnected: in the customer, distribution or transmission domain. The decision states that a storage resource interconnected in the customer domain may provide services in any domain, resources interconnected in the distribution domain may provide services in all domains except the customer domain, with the possible exception of community storage resources, and resources connected in the transmission domain may provide services only in that domain. Resources interconnected anywhere may provide resource adequacy, transmission and wholesale market services.

iii. California Brattle study

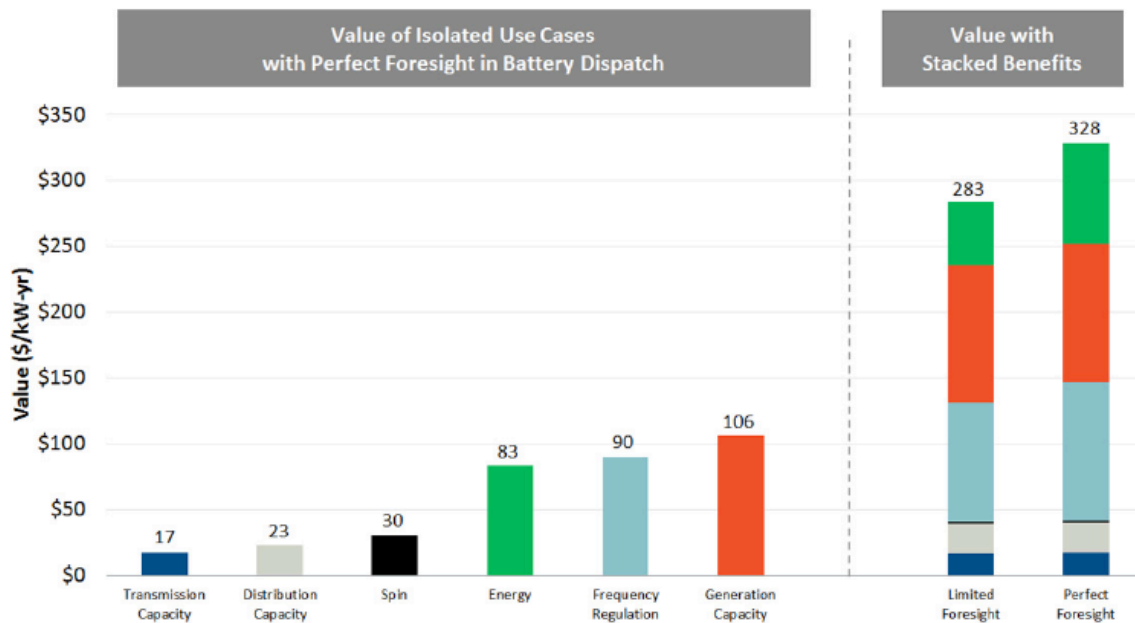
A 2017 Brattle study sought to quantify the wholesale market values that storage could provide in California, specifically, the avoided system costs.¹⁸³ The sources of value they sought to quantify include: energy price arbitrage, ancillary services (frequency regulation and spinning reserves), generation capacity/resource adequacy, transmission and distribution capacity and reduced CO₂ emissions.¹⁸⁴ The study did not look at the value of bill reductions for customers (e.g., avoided demand charges), improved reliability (e.g., backup generation) or enhanced power quality. The Brattle study results show that some sources of value will need to be forgone to ensure sufficient energy is available in the battery to serve higher value sources at other times. Notably, the Brattle results show a stacked value of storage is only 6% less than the sum of the individual value streams, highlighting the importance and benefit of pursuing multiple streams simultaneously. Figure 21 illustrates the findings from this study.¹⁸⁵

¹⁸² CPUC (2018, January 11). Proposed decision of Commissioner Peterman before the California Public Utilities Commission. Retrieved from: <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M204/K478/204478235.pdf>

¹⁸³ Hledik, R., Lueken, R., McIntyre, C., and Bishop, H. (2017, September). *Stacked benefits: Comprehensively valuing battery storage in California*. Cambridge, MA: The Brattle Group. Retrieved from: http://files.brattle.com/files/7208_stacked_benefits_-_final_report.pdf

¹⁸⁴ Sources of system value that were not quantified include: reduced transmission congestion, extension of transmission and distribution equipment life, additional ancillary services (e.g., ramping, black start, voltage support), flexible resource adequacy value and avoided start-up costs of other generators on the system.

¹⁸⁵ Hledik et al., 2017.

Figure 21. Battery Value for Individual Use Cases and Stacked Benefits¹⁸⁶

Note: Results shown for San Diego. Value in other California locations is assessed through sensitivity analysis. Energy and ancillary services value is an average across market conditions between 2013 and 2016.

iv. PG&E storage value evaluation

Under California's Electric Program Investment Charge program, Pacific Gas and Electric Company (PG&E) evaluated participation in CAISO markets using the NGR model for two distribution network-connected sodium-sulfur battery energy storage facilities: the 2 MW Vaca-Dixon battery in Vacaville, California, and the 4 MW Yerba Buena battery in San Jose. These were the first battery storage facilities to participate in CAISO markets as NGRs. According to PG&E's 2016 assessment report, the most advantageous revenue stream from CAISO for the facilities came from participation in the frequency regulation (FR) markets.¹⁸⁷ As such, the full battery capacity was bid into the FR market, which had a relatively flat price for most of the study period until February 2016, when prices increased significantly. The difference in FR average prices between 2015 and 2016 provides a useful comparison for how revenues were accruing to the resource during different time periods. As Table 13 shows, in 2016 a combination of higher FR prices and the ability to participate for a full 24 hours (due to an operational change made by CAISO over this time period) resulted in much higher revenues to the battery storage device.

¹⁸⁶ Hledik et al., 2017.

¹⁸⁷ Penna, M. D., Yeung, M., and Fribush, D. (2016, September 13). *EPIC (Electric Program Investment Charge) final report*. Pacific Gas and Electric Company. Retrieved from: https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-1.01.pdf

Table 13. Vaca BESS Settlements for FR¹⁸⁸

	Sample Month 2015	Sample Month 2016
Market Model	NGR Non-REM	NGR REM
Days	31	31
Hours per day of regulation	18	24
Regulating Range	-2.14 MW to 1.85 MW (4MW total range)	-1.3 MW to 1.3MW (2.6MW total range)
Average RegUp Price (\$/MW/hr)	\$4.67	\$15.94
Average RegDn Price (\$/MW/hr)	\$2.42	\$11.41
Regulation Capacity Revenues	\$8,251	\$39,552 ⁵¹
Mileage Revenues ⁵²	\$2,721	\$598
Energy Revenues	(\$2,592)	(\$5,291)
Other Revenues	(\$100)	(\$94)
Total Monthly Revenues	\$8,279	\$34,765
Annualized Revenues	\$99,000	\$417,000

In contrast to Brattle’s findings, the PG&E case study found that participation in the day-ahead and real-time energy markets was not worthwhile because energy price differentials in these markets were not consistently large enough to arbitrage. That is, the facilities could not regularly find large enough differentials to cover the costs of round-trip losses to charge and discharge. This may have been partly due to location: if the facilities had been located at nodes where negative prices occurred more frequently, then the business case for energy market arbitrage may have been stronger. Given the dominance of revenues from frequency regulation services, PG&E surmised that it might have been more cost effective — at least given location and market dynamics that were experienced in the study — to invest in shorter duration batteries, say, 30-minute instead of seven-hour duration batteries. Meanwhile, these facilities also provided value on the local distribution network.¹⁸⁹

¹⁸⁸ Penna et al., 2016.

¹⁸⁹ Penna et al., 2016.

v. Massachusetts energy storage initiative

Like California, Massachusetts has undertaken an energy storage initiative. In September 2016, a group of Massachusetts agencies, stakeholders and consultants released a study of storage deployment in the Commonwealth.¹⁹⁰ The study found that large-scale deployment (up to 1,766 MW) of new energy storage, deployed at appropriate locations with the right sizing and dispatched to maximize capability, would result in \$2.3 billion in benefits for Massachusetts's ratepayers.

The model utilized for this study identified specific locations and quantities of storage through multiple iterations of capacity and production cost optimization.¹⁹¹ Taking into account the cost of up to 1,766 MW of storage, the study found that the benefit-cost ratio for ratepayers could range from 1.7 to 2.4. The benefits to ratepayers come from cost savings in the form of:

- Reduced prices paid for electricity
- Lower peak demand (~10%)
- Deferred T&D investments
- Reduced GHG emissions compliance costs
- Reduced cost of integrating RE
- Deferred capacity investments
- Increased reliability and resiliency.

Table 14 shows the ratepayer savings benefits of storage in the Massachusetts study.¹⁹²

The Massachusetts study also found that the New England region would see an additional \$250 million from reduced ISO-NE wholesale market prices. This amount of storage is projected to reduce GHG emissions by more than 1 million metric tons over a 10-year period.

¹⁹⁰ DOER and MassCEC (2015). *State of charge: A comprehensive study of energy storage in Massachusetts*. Massachusetts Department of Energy Resources and Mass Clean Energy Center. Retrieved from <https://www.mass.gov/service-details/energy-storage-study>

¹⁹¹ The model simulated the ISO-NE markets in a way that co-optimizes energy and ancillary services subject to transmission thermal constraints with detailed Massachusetts-specific generation, transmission and distribution data. It includes an import and export flow model to represent interfaces with NYISO, IESO, Hydro Quebec and New Brunswick Power. The existing generation resource mix is used and accounts for retirements and additions during the study period. The model was benchmarked for 2015.

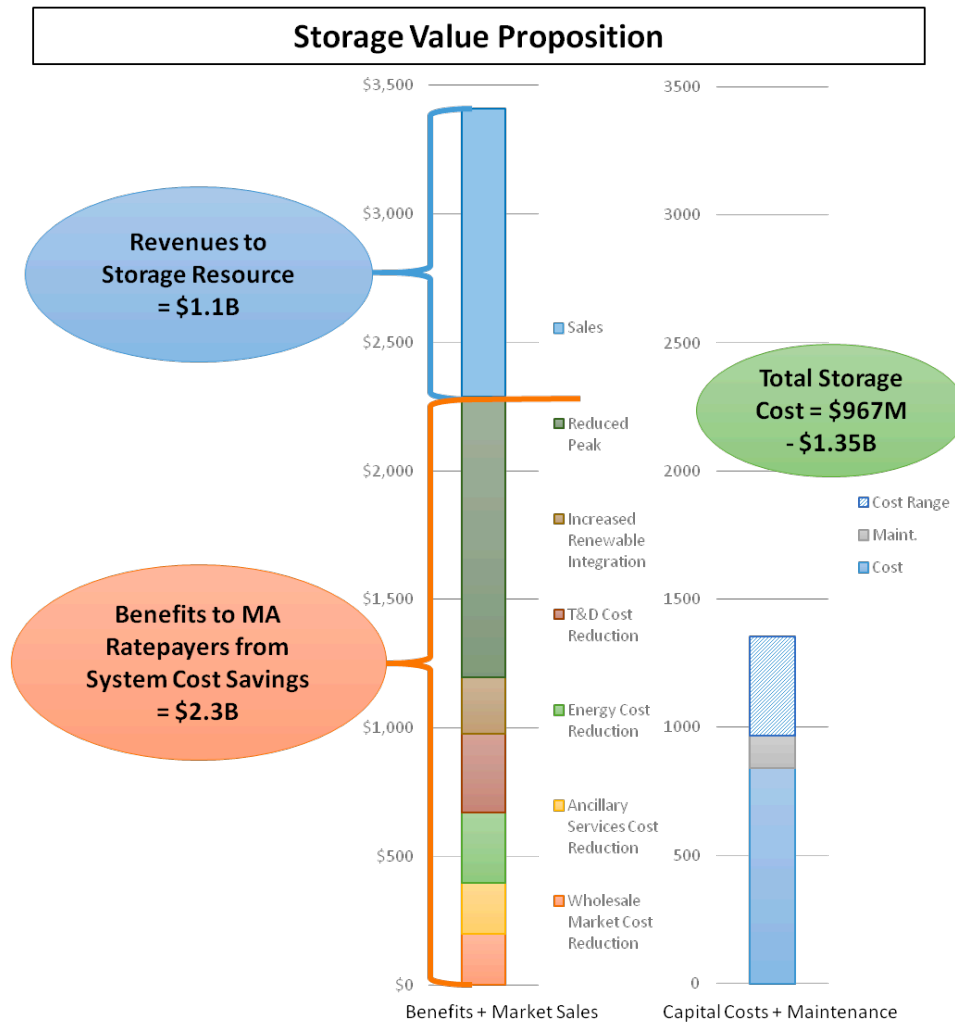
¹⁹² DOER and MassCEC, 2015.

Table 14. Ratepayer Savings in Massachusetts¹⁹³

Benefit Description	Ratepayer Savings
Energy Cost Reduction Energy storage uses lower cost energy stored at off-peak to replace the use of higher cost peak generation: <ul style="list-style-type: none"> • reduced peak prices • reduced overall average energy price 	\$275M
Reduced Peak Capacity Energy storage can provide peaking capacity to: <ul style="list-style-type: none"> • defer the capital costs peaker plants • reduce cost in the capacity market 	\$1093M
Ancillary Services Cost Reduction Energy storage would reduce the overall costs of ancillary services required by the grid system through: <ul style="list-style-type: none"> • frequency regulation • spinning reserve • voltage stabilization 	\$200M
Wholesale Market Cost Reduction Energy storage provides system flexibility, reducing the need to ramp generators up and down and resulting in: <ul style="list-style-type: none"> • less wear and tear • reduced start up and shut down costs • reduced GHG emissions (lower compliance cost) 	\$197M
T&D Cost Reduction Energy storage: <ul style="list-style-type: none"> • reduces the losses and maintenance of system • provides reactive power support • increases resilience • defers investment 	\$305M
Integrating Distributed Renewable Generation Cost Reduction Energy storage reduces cost in integrating distributed renewable energy by: <ul style="list-style-type: none"> • addressing reverse power flow at substations • avoiding feeder upgrades at substations 	\$219M
Total System Benefits	\$2,288M

The Massachusetts study also found that storage projects can provide benefits to all ratepayers and direct revenue to the storage resource owners. The modeling showed an additional \$1.1 billion in direct benefits to the resource owners from market revenue. The entire value proposition for the quantity of storage modeled by the study is shown below in Figure 22.

¹⁹³ DOER and MassCEC, 2015.

Figure 22. Storage Value Proposition¹⁹⁴

The study highlights that existing market and revenue mechanisms need to be revisited for potential benefits to be captured and to justify an investment in storage from the perspective of a private developer. Some of these revenue mechanisms are ISO-NE market rules, which were discussed in the previous subsection.

¹⁹⁴ DOER and MassCEC, 2015.

vi. Texas Brattle study

The Brattle Group analyzed the net benefits of energy storage in Texas from the perspectives of wholesale market participants, the grid as a whole and retail electric customers.¹⁹⁵ That is, they analyzed the value a merchant developer might see from wholesale market participation, the system-wide benefits of storage and the benefits to retail customers if storage assets were deployed under a framework that allowed the full value of the assets to be captured.¹⁹⁶

The study finds that the Texas market would benefit from storage deployment with storage costs at or below \$350/kWh.¹⁹⁷ The Texas system would see incremental net benefits with up to 5,000 MW of storage. The study also concludes that multiple value streams need to be available to storage operators for the full value of storage to be captured. Capturing only the wholesale market values, or only the transmission and distribution system benefits, would result in underinvestment and underutilization of energy storage on a system-wide basis.

The first stream of benefits analyzed was the net revenues that storage could earn from ERCOT wholesale power markets, that is, net profits that could be earned by charging during low-price periods, discharging during high-price periods, and participating in the ancillary services market.¹⁹⁸ These wholesale market benefits alone are small in comparison to current storage costs, and only a modest amount of storage could be attractive purely on a wholesale-market basis at storage costs of \$350/kWh.

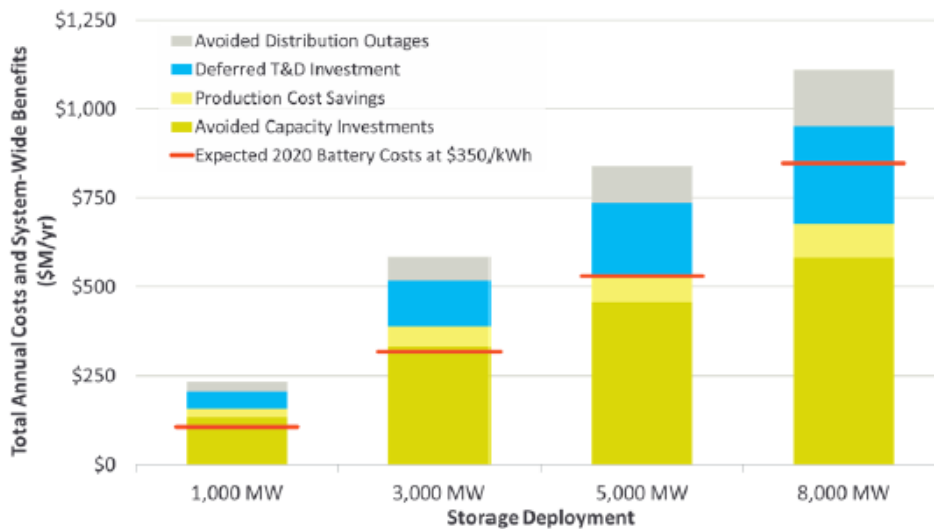
The second stream of benefits analyzed was the system-wide benefits of storage, including four components of storage value from an annualized, system-side perspective: (1) avoided distribution outages, (2) deferred transmission and distribution investments, (3) production cost savings and (4) avoided generation investments. The combined value of these benefits exceeds the cost of storage even at an ERCOT-wide deployment level of 8,000 MW. Figure 23 shows the system-wide benefits at different levels of storage deployment, compared to an estimated 2020 cost of storage at \$350/kWh.

¹⁹⁵ Chang, J., Pfeifenberger, J., Spees, K., Davis, M., Karkatsouli, I., Regan, L., and Marshal, J. (2014, November). *The value of distributed electricity storage in Texas: Proposed policy for enabling grid-integrated storage investments*. Prepared for ONCOR. Cambridge, MA: The Brattle Group. Retrieved from: http://files.brattle.com/files/7589_the_value_of_distributed_electricity_storage_in_texas.pdf

¹⁹⁶ The study does not analyze benefits of supporting customer-sited distributed generation.

¹⁹⁷ According to Lazard, capital cost of lithium ion storage devices ranges from \$320 to \$1,089/kWh. For the purposes of this study, the Brattle team assumed that storage costs would come down to around \$350/kWh by 2020 based on discussions with vendors and consistent with industry projections. Jaffe, S. (2014, September). *Energy storage supply chain opportunities*. Navigant Research. Retrieved from: https://www.eastmanbusinesspark.com/files/73byai/Sam_Jaffe_Navigant%20Energy_Supply_Chain.pdf

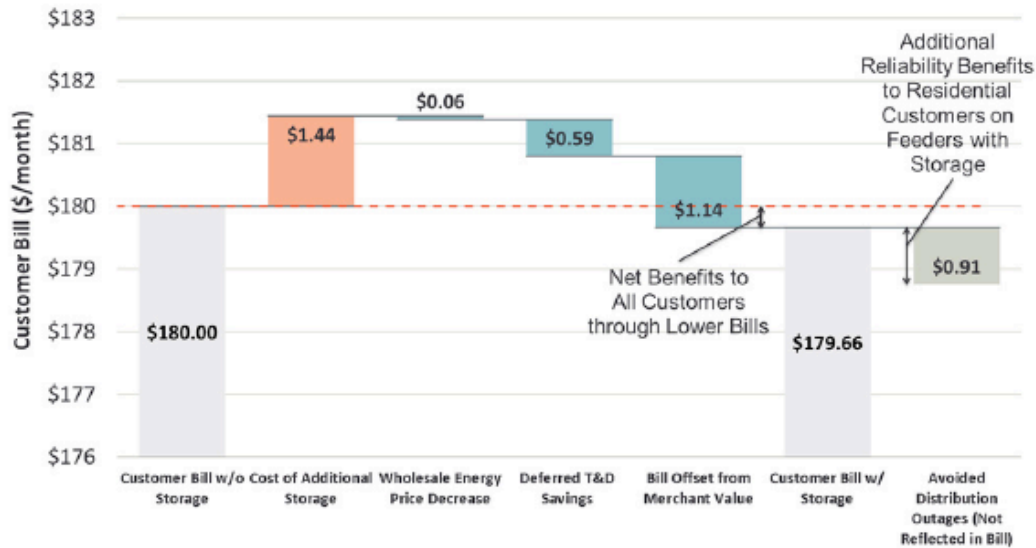
¹⁹⁸ The Polaris Systems Optimization market simulation tool was used to conduct this study using fuel price, market pricing and generation mix in the Texas market for the year 2020.

Figure 23. Storage Deployment¹⁹⁹

In addition to the benefits just described, the study estimated the benefits and costs to all customers. The study assumed that most (but not all) of the benefits from a societal perspective would be realized by customers of utilities, including the value associated with deferred transmission and distribution investments. Customers also benefit from power purchase cost savings (though this is found to be small) and offsets from merchant value that independent market participants obtain in the wholesale markets. The merchant value is the net profits that a private investor could monetize by participating in the wholesale markets for energy and ancillary services. The analysis assumes that retail customers would be able to benefit from approximately 75% of that merchant value, with the remaining 25% being kept by the entity who contracts to use the storage for participation in the market.

Figure 24 shows the effect of deploying 3,000 MW of storage across the Texas wholesale market on average residential customer bills. Typical bills would go down by a small amount, and customers located on feeders where storage is installed would see a benefit from improved reliability.

¹⁹⁹ Chang et al., 2014.

Figure 24. Impact on a Typical Customer Bill in 2020²⁰⁰**Impact on a Typical Customer Bill in 2020 Assuming 3,000 MW of Storage Installed in ERCOT
(1,000 MW Installed on Oncor's System)****Sources and Notes:**

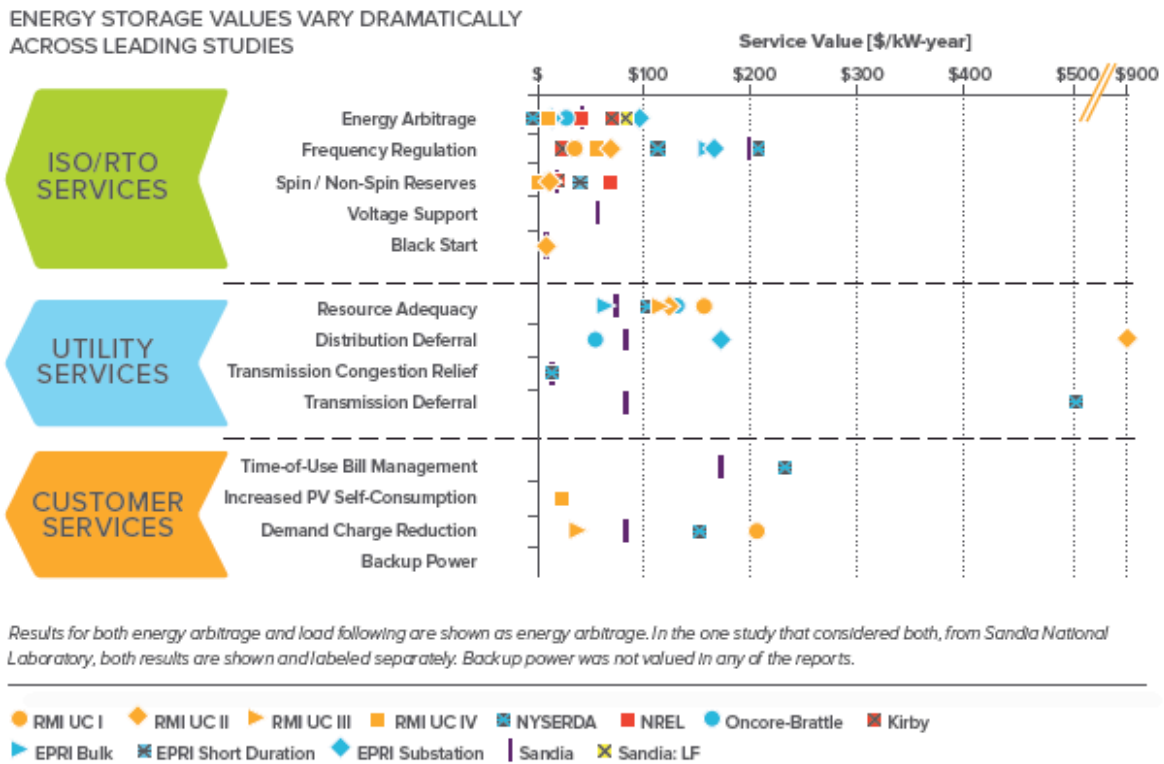
We assume that Oncor installs 1,000 MW out of 3,000 MW of storage deployed on an ERCOT-wide basis, with storage costs and wholesale-market proceeds reflecting the same proportion of installations. Oncor customers realize deferred transmission and distribution investment benefits based on the 1,000 MW installed on Oncor's system. The avoided distribution outage value shown is for a typical residential customer on a feeder with storage. Customers not located on a feeder with storage would not realize these reliability benefits.

vii. Rocky Mountain Institute summary of studies

In 2015, Rocky Mountain Institute (RMI) completed an analysis of multiple studies of the value of storage, including four use cases that RMI itself defined.²⁰¹ In doing so, RMI found 13 services that storage is capable of providing to the electricity system, and values for those services, which ranged widely depending on the study. Figure 25 offers a summary of RMI's results.

²⁰⁰ Chang et al., 2014.

²⁰¹ Fitzgerald, G., Mandel, J., Morris, J., and Touati, H. (2015, September). *The economics of battery energy storage: How multi-use, customer-sited batteries deliver the most services and value to customers and the grid*. Boulder, CO: Rocky Mountain Institute. Retrieved from: <https://rmi.org/wp-content/uploads/2017/03/RMI-TheEconomicsOfBatteryEnergyStorage-FullReport-FINAL.pdf>

Figure 25. Energy Storage Values Across Leading Studies²⁰²

RMI concluded that energy storage can generate much more value when multiple services are provided but the net value of behind-the-meter storage is difficult to generalize. The four use cases for behind-the-meter storage that RMI analyzed demonstrated that by combining a primary service with a bundle of other services, batteries can provide a net economic benefit to the battery owner or operator.

2. Value stack discussion of storage

Estimates of the value for each service that batteries can provide — and, therefore, the total stacked value of any particular battery storage system — depends on a multitude of factors, including use case (i.e., what services are prioritized over others), location, time day and system conditions, year, fossil fuel prices, technology efficiencies and other factors.

a. Values akin to grid-scale generation

i. Production cost savings

Storage can be used to shift electricity production from higher cost to lower cost times of day and lower cost resources. This could be calculated as the reduced costs of fuel and variable operating and maintenance costs.

In the Texas Brattle study, this is estimated by simulating the ERCOT wholesale energy and

²⁰² Fitzgerald et al., 2015.

ancillary services market in 2020. Storage dispatch includes the 15% round-trip efficiency loss. These cost savings are expressed as the reduced costs for fuel, variable operations and maintenance costs and demand response deployment costs on an ERCOT-wide basis.

ii. Energy cost reduction

In the Massachusetts study, the energy cost reduction value is estimated as a reduction in electricity prices. Energy storage has an impact on the price of electricity in the wholesale market by storing electricity in off peak periods and resulting in lower locational marginal prices. The study found that adding energy storage in Massachusetts yields a consistently lower annual average wholesale energy price across all ISO-NE zones. This is sometimes also referred to as wholesale energy price suppression or DRIPE (demand reduction induced price effect). The three Massachusetts zones analyzed in this study (NEMA-Bost, SEMASS and WCMASS) saw energy price reductions of \$0.0002/kWh, \$0.00029/kWh and \$0.00026/kWh, respectively. The study estimated a 2020 energy price reduction of \$0.00019/kWh due to the Massachusetts deployment of storage.

iii. Avoided generation capacity investments

By deploying storage to reduce load during peak times, there is a reduction in the necessary amount of generation capacity investments. This cost is the marginal resource investment — a natural gas combined cycle plant or gas turbine in New England. The 2018 forward capacity market in ISO-NE cleared at \$4.63/kWh-month²⁰³ for the commitment period of June 1, 2021, through May 31, 2022.

In the Texas Brattle study, the marginal resource investment has costs similar to a natural gas combined cycle plant, estimated to be a levelized annual cost of \$149/kW-year. In the Massachusetts study, the estimated capital cost for a new natural gas combustion turbine peaking plant based on assumptions adopted from EIA's AEO 2015 report is \$973/kW.

iv. Ancillary services provisions

Energy storage can provide ancillary services like frequency regulation, spinning reserve and voltage stabilization, often at lower cost than other resource options.

In the Massachusetts study, values for the ISO-NE forward reserve markets for 10-minute spinning reserves, 10-minute non-spinning reserves and 10-minute operational reserves are estimated. The frequency regulation market encompasses both an upward and downward regulation service. Storage can provide these services at lower cost than conventional generating units because, unlike generators, they do not need to be kept at a minimum load to be able to respond within 10 minutes. In contrast to traditional generation, storage systems have a fast response time and relatively low cost to keep the unit ready. Using storage for these services also reduces wear and tear on generators from high-ramping rates.²⁰⁴ The study estimates total ancillary services cost reductions of \$200 million from using 1,766 MW of storage.

²⁰³ Resources that clear in these auctions receive monthly payments in exchange for their commitment to be available to meet the projected demand for electricity three years out. That delivery period is called the capacity commitment period (CCP) — a one-year period from June 1 through May 31 of the following year.

²⁰⁴ The Massachusetts study highlights that in order for these benefits to be achieved, ISO-NE market rules would need to be updated to be able to dispatch energy storage with other dispatchable generation in the system.

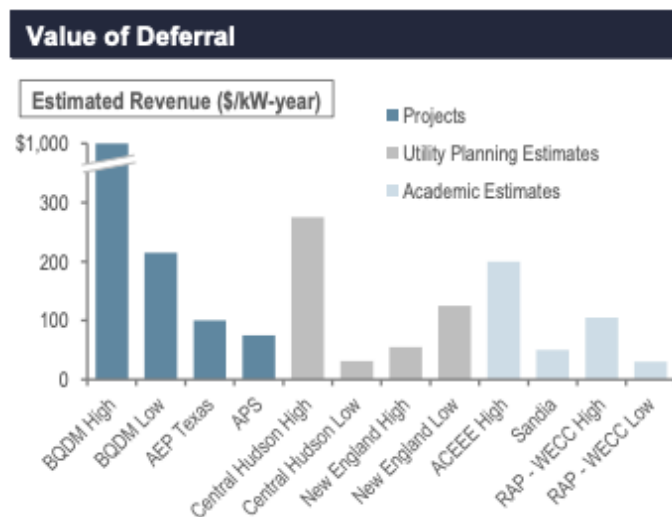
b. Values akin to traditional bulk transmission

These costs are challenging to accurately quantify because these benefits are very location specific and partly because the analysis requires a large amount of granular data that utilities do not wish to make public. For deferred transmission investments, deploying storage close to load can allow it to be discharged during peak periods to serve load, which may reduce future transmission investment needs. To estimate the potential effect of deferred transmission investments, a detailed transmission planning effort for varying levels of storage deployment would be useful. The deferred transmission system-wide can be estimated by looking at the average annual transmission cost for reducing peak demand. In the Texas Brattle Study, deferral of transmission investments is estimated using the average annual transmission cost for every unit of reduced peak demand. This is approximately \$36/kW-year, per average annual transmission cost per kW of summer CP demand in ERCOT.

A useful metric could be the current annual transmission cost per kW of summer peak for system-wide bulk transmission savings.²⁰⁵

Lazard's levelized cost of storage analysis included a summary of location-based grid services, specifically T&D deferral applications. Figure 26 shows Lazard's analysis of actual projects, utility planning estimates and academic estimates.

Figure 26. Value of Deferral²⁰⁶



c. Values akin to distribution plant

i. Deferred distribution investments

A full distribution system needs analysis would be useful to know the number and costs of high-value distribution deferrals possible and would provide a look at the utility's annual distribution investments, load growth and ability of storage to defer or avoid some of the upgrades.

²⁰⁵ There are various forms in which the marginal or average transmission cost of serving peak can be expressed.

²⁰⁶ Lazard, 2018. Used with permission.

In the Texas Brattle study, the deferral or avoidance of distribution investments was a more utility-specific analysis than for bulk transmission. An approximate estimate of the number of higher-value distribution investment deferral opportunities was made, and all of these opportunities were assumed to be pursued first. The study does not report a specific value for these higher value opportunities. For all additional battery deployments, the study used a lower \$14/kW-year value based on the particular utility's average annual distribution investments and annual load growth in 2014.

ii. Avoiding outages and interruptions in service

Storage can be used to avoid costly outages on certain feeders. This can improve reliability and provide benefits to many customers. One metric that could be useful for estimating this value is the value of lost load (VOLL) for different customer classes.

In the Texas Brattle study, historical outage patterns were used to simulate a storage deployment that targeted feeders with lower-than-average reliability. VOLL for different customer classes is used to estimate value. VOLL for commercial and industrial customers is estimated at approximately \$20/kWh and for residential customers at approximately \$3/kWh.

iii. Renewables integration

Storage can assist in the integration of distributed generation in a number of ways, which are captured elsewhere in the layer cake. Another benefit to DG from storage is helping to solve the reverse power flow issues associated with solar. Costly distribution upgrades due to reverse power flow concerns can increase the costs of deploying DG. Storage at the distribution substation utilized as a distribution asset or distributed at customer premises can eliminate or manage circuit reverse power flow by charging with the solar surplus and discharging during times of high demand.

d. Values to customer premises

i. Demand charge reduction

Most large customers are subject to demand charges, which are often based on the highest instantaneous usage of energy within a defined time period (usually over a 15-minute or hour-long period). Demand charges are typically billed monthly but assessed based on the customers' highest demand at any point in the preceding year. (Some utilities assess demand charges based only on the highest usage of that month.) The presence of demand charges opens up an opportunity for storage to provide value behind the meter to these customers. Storage can be used to reduce a customer's peak demand therefore reducing the demand charge. It can also potentially help keep customers from being shifted into a more expensive tariff schedule. The studies summarized in Figure 25 found a range for the value of demand charge reductions from \$58/kW-year to \$269/kW-year.

The significance of this value for individual customers will vary quite a bit and will depend in part on the structure of retail rates.

ii. Reduced energy costs

In addition to reduced wholesale electricity prices that result from storage on the system (discussed above under production cost savings), behind-the-meter storage can be managed by the customer to minimize grid purchases during peak periods that have a higher time-of-use rate associated with them. The value of managing a storage system in this way will depend heavily on the tariff

structure, usage patterns and availability of on-site generation. In a use case examining residential time-of-use bill management in Phoenix, Arizona, RMI found that managing a storage system primarily for bill savings would allow the battery to be deployed for other grid services 90% of the time, while reducing the customer's bill by 20%.²⁰⁷

iii. Resilience/reliability from reduced outages

Customers located on feeders with energy storage will benefit from reduced outages and increased reliability, as mentioned above. Customers with behind-the-meter storage will also have the ability to meet some or all of their energy needs during grid outages, enhancing those customers' resilience to grid disruptions.

iv. Societal/public value – improved air quality

Storage can reduce emissions of local air pollutants and greenhouse gases caused by electricity generation if the device is charged up while clean electricity resources are abundant and operating on the margin. Storage that is located on the distribution system can reduce line losses and therefore reduce emissions. However, if storage is discharging at times when clean resources are generating on the margin, the storage device is not offsetting or reducing any emissions. These factors make quantifying the air quality benefits of storage resources complicated and situation specific. The Massachusetts study discussed above found that deploying 1,766 MW of storage would result in a 1 million metric ton reduction of GHGs over a 10-year period.

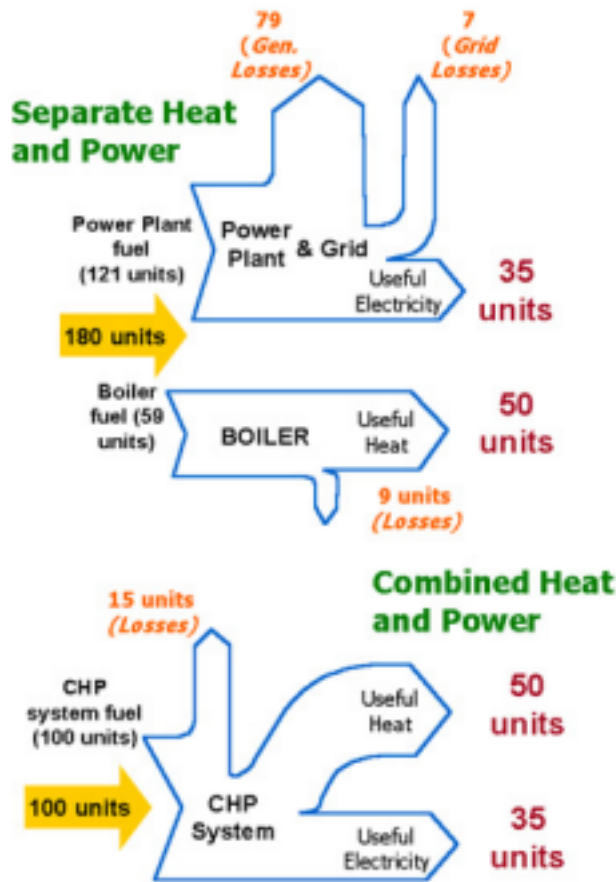
Appendix D: Combined Heat and Power

1. Background

Combined heat and power (CHP) systems are resources located on-site in commercial, industrial or institutional settings that generate both heat and power. Because of its location on-site at the point of consumption, CHP is considered distributed generation even though some systems can be quite large. Traditionally, electricity is generated at a central power plant, and on-site heating and cooling uses heat from the combustion process to meet nonelectric energy requirements. In a CHP system, the electricity is produced on-site, and the thermal energy is recovered to be used for heating or cooling nearby buildings or in industrial processes. Because CHP captures heat that would otherwise be wasted in the case of traditional generation of electric power, the combined efficiency of these integrated systems is much greater than from traditional separate systems.²⁰⁸ Figure 27 illustrates energy losses by type of generation.

²⁰⁷ Fitzgerald, G., Mandel, J., Morris, J., and Touati, H. (2015, September). *The economics of battery energy storage: How multi-use, customer-sited batteries deliver the most services and value to customers and the grid*. Boulder, CO: Rocky Mountain Institute. Retrieved from: <https://rmi.org/wp-content/uploads/2017/03/RMI-TheEconomicsOfBatteryEnergyStorage-FullReport-FINAL.pdf>

²⁰⁸ Chittum, A., and Elliot, N. (2009). *Combined heat and power and clean distributed energy policies* [policy brief]. American Council for an Energy-Efficient Economy (ACEEE). Retrieved from: http://aceee.org/files/pdf/fact-sheet/chp_policyposition0809.pdf

Figure 27. Comparison of a CHP System With a Traditional System²⁰⁹

CHP is widely used in the United States and has been for decades. In 2016, over 82.7 GW of CHP capacity existed at over 4,400 industrial and commercial facilities across the country. This represents 8% of U.S. electricity generation capacity; however, it represents over 12% of annual U.S. power generation, reflecting the higher utilization rates of CHP systems as compared to conventional forms of generation.²¹⁰

CHP can use a variety of fuels to generate electricity.²¹¹ Gas turbines are the most common kind of CHP generation. CHP systems can be extremely efficient. In a traditional, centralized, electricity-only plant, gas turbines run at 30% efficiency. When fuel is burned in a boiler, efficiency can be 80%. The two systems averaged together achieve roughly 50% efficiency. But when fuel is burned in a CHP configuration that generates electricity and recovers heat and uses it for a productive purpose, gas turbine CHP systems run at 65–75% efficiency while producing both electricity and

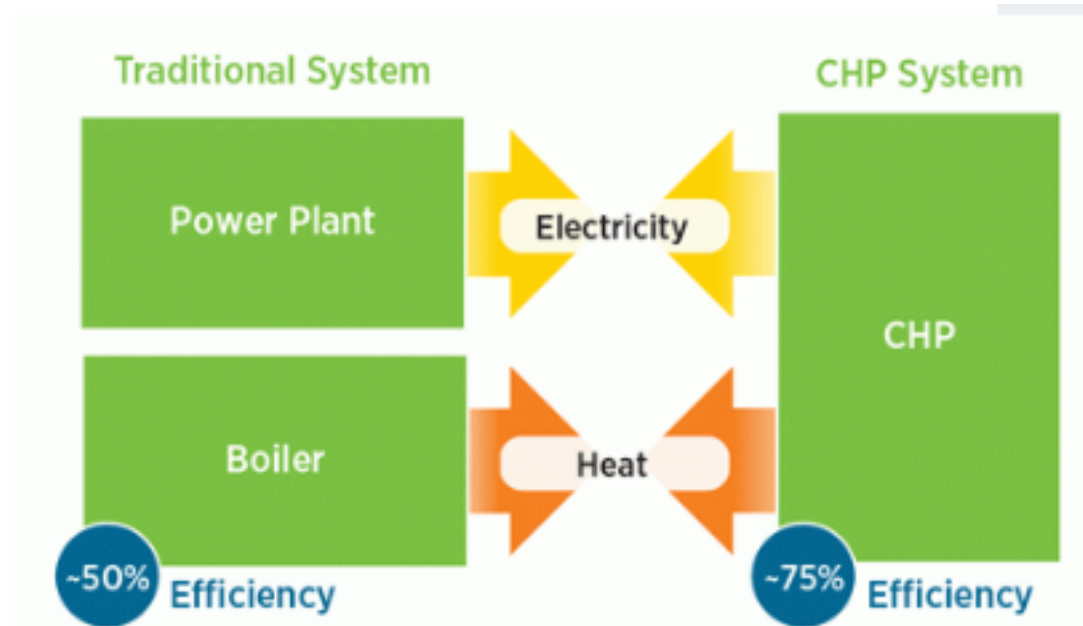
²⁰⁹ Chittum and Elliot, 2009.

²¹⁰ U.S. DOE (2016). *Combined heat and power (CHP) technical potential in the United States*, p. 15. Retrieved from: <https://www.energy.gov/sites/prod/files/2016/04/f30/CHP%20Technical%20Potential%20Study%203-31-2016%20Final.pdf>

²¹¹ U.S. DOE (undated-b). *Combined heat and power basics* [web page]. Retrieved from: <https://www.energy.gov/eere/amo/combined-heat-and-power-basics>.

heat together.²¹² This efficiency makes CHP a very cost-effective way to meet on-site energy needs. Figure 28 illustrates how a CHP system works.

Figure 28. CHP System Efficiency²¹³



CHP is widely used in the steel, chemical, paper and petroleum-refining industries and at large institutional campuses such as universities. In recent years, smaller CHP systems have begun to be used in the food, pharmaceutical and light manufacturing industries; in commercial buildings; and at smaller institutions such as hospitals.²¹⁴

There are a couple different ways to use CHP, and it is typically distinguished as either topping cycle or bottoming cycle generation. In a “bottoming-cycle” configuration, also known as waste heat to power, the primary function is to combust fuel to provide thermal input to an industrial process, such as in a steel mill, cement kiln, or refinery. Waste heat is then recovered from the exhaust for power generation, usually through a heat recovery boiler that makes high pressure steam to drive a turbine generator. More common is a “topping-cycle” system, a configuration in which a steam turbine, gas turbine, or reciprocating engine has the primary purpose of generating electricity. Heat is then captured, usually as steam, and directed to nearby facilities, where it can be used to meet co-located demand for central heating or manufacturing processes.²¹⁵ Industrial CHP applications can

²¹² Chittum, A., and Relf, G. (2018, April 15). *Valuing distributed energy resources: Combined heat and power and the modern grid* [white paper]. ACEEE. Retrieved from: <https://aceee.org/white-paper/valuing-der>

²¹³ U.S. DOE, undated-b.

²¹⁴ Chittum and Elliot, 2009.

²¹⁵ NACAA (2015). *Implementing EPA’s Clean Power Plan: A menu of options. Chapter 2: Implement combined heat and power in the electric sector*. Retrieved from: <http://www.4cleanair.org/news/details/nacaa-releases-clean-power-plan-implementation-tool-0>

be either topping or bottoming cycles depending on the industry and technology. For the commercial sector, all applications are topping cycles, and CHP is used specifically to serve a building's cooling needs.²¹⁶

2. CHP and value to the customer and the grid

CHP provides a mixture of energy efficiency and distributed generation benefits to the grid. It provides energy efficiency benefits because it is more efficient than separately producing useful thermal energy and electricity. Like other forms of DG, CHP also displaces grid-supplied power and reduces line losses, thus it provides a reduction in load. This higher efficiency translates to lower operating costs (albeit with capital investment). This higher efficiency (and decrease in total energy demand) reduces emissions of pollutants, and it provides increased energy reliability and enhanced power quality for customers.

However, unlike energy efficiency programs run by utilities, which feature the aggregated benefits of thousands of energy efficiency improvements, CHP opportunities are focused on a few, generally mid-sized to large industrial, commercial and critical facility-based customers, each of which is unique. It requires upfront capital investment, which will vary depending upon the size, technology and fuel type used. This mix of technologies and fuel types makes CHP versatile. It also makes it difficult to classify in-state policies that seek to increase DERs. Because it is often powered by fossil fuels, CHP is sometimes excluded from state renewable energy programs, or if it is included such programs are limited to CHP systems fueled by renewable sources. Because it can supply electricity as well as reduce electricity consumption and is larger and more complex than simple energy efficiency measures, it rarely fits into standard utility or local energy efficiency programs, and there are few true CHP programs among utility and state energy efficiency programs.²¹⁷

Most of the valuation studies on CHP have narrowly focused on value to the customer, usually in the form of more efficient generation, which makes a good return on investment. These customers generally care most about costs, reliability and resiliency. Some CHP valuation studies have focused on values to the grid from CHP, and others have focused on the locational value of CHP and emissions values.

3. Value stacking of benefits for CHP

a. Values akin to grid-scale generation

i. Production energy value

CHP provides production energy value to the grid as a whole by reducing customer demand for grid-supplied electricity at the CHP site. Since CHP owners tend to be industrial, commercial and

²¹⁶ Weiss, J., Faruqi, A., and Hledik, R. (2015). *Combined heat and power (CHP) policy review for the Kingdom of Saudi Arabia*. Cambridge, MA: The Brattle Group. Retrieved from:

[http://files.brattle.com/files/5656_combined_heat_and_power_\(chp\)_policy_review_for_the_kingdom_of_saudi_arabia.pdf](http://files.brattle.com/files/5656_combined_heat_and_power_(chp)_policy_review_for_the_kingdom_of_saudi_arabia.pdf)

²¹⁷ Chittum, A., and Kaufman, N. (2011, September). *Challenges facing combined heat and power today: A state-by-state assessment*.

ACEEE. Retrieved from: <https://www.iowaeconomicdevelopment.com/userdocs/documents/ieda/ACEEE2011statebystate.pdf>

critical infrastructure sites such as hospitals and universities, the reduction in demand can be quite large. The average system size of currently installed industrial CHP systems in the United States is approximately 53 MW, while the median size is much lower at 7 MW.²¹⁸

CHP systems do not typically go beyond reducing demand to produce net energy to the system, but they can be designed to do so. Consequently, CHP can both provide avoided energy value and market price suppression effects similar to other DERs. The efficiencies obtained from CHP systems is dependent upon certain design considerations, which in turn impact whether the system can be designed to export to the grid or not. First, the sizing of the CHP system is critical to obtaining maximum efficiency benefits. Experience has shown that: 1) a CHP boiler should not run below a minimum load; 2) a system that is too large will not operate enough, but a system that is too small will not provide the full cost savings; and 3) poorly sized systems will not perform optimally.²¹⁹ Thus, while it is possible to size a unit to export excess energy to the grid, especially when a customer's needs for process steam or other forms of useful thermal energy drive the decisions about CHP system size, this option must be carefully evaluated as exported electricity can have a significantly lower value than electricity consumed on-site.²²⁰ Barriers to CHP electricity export from utilities and state regulations are such that this has not been substantially utilized in the United States. As a result, CHP participation in energy markets is very low.

The Department of Energy has proposed utilizing flexible CHP as a way to provide value to the grid and value to the host site. Bristol-Myers Squibb, a global biopharmaceutical company, operates CHP systems at many of its manufacturing facilities. When the company was deciding whether to install a CHP system at its plant in Hopewell, New Jersey, conventional CHP project economics — including energy savings and available financial incentives — did not justify the investment. The economic feasibility of the system, which consists of two reciprocating engines for a total capacity of 4.1 MW, improved significantly when the system was configured to participate in PJM Interconnection electricity markets. Estimated annual revenue from capacity, energy and other grid services in the PJM market totaled \$1.4 million, or \$340,000 per MW.²²¹

ii. Production capacity value

CHP reduces peak demand needs for the system as a whole by providing efficient on-site generation for industrial, commercial and other facilities. CHP in the United States was 82.6 GW in 2016.

CHP currently represents approximately 8% of U.S. generating capacity, compared to over 30% in countries such as Denmark, Finland and the Netherlands. This low penetration is reflective of the

²¹⁸ U.S. DOE, 2016. Note that industrial facilities typically require large CHP systems. Other CHP sites may be more moderately sized depending on the size and needs of the site.

²¹⁹ Ener-G (undated). *A guide to CHP unit sizing*. Retrieved from: http://cdn2.hubspot.net/hub/319497/file-647619846-pdf/Docs/A_guide_to_CHP_unit_sizing_v3_01.pdf?t=1469537808731

²²⁰ Ener-G, undated.

²²¹ U.S. Department of Energy (2018). *Flexible combined heat and power (CHP) systems*. Retrieved from: https://www.energy.gov/sites/prod/files/2018/01/f47/Flexible%20CHP%20Comms_01.18.18_compliant.pdf

barriers that exist to CHP in the United States. According to a 2016 US DOE report, these barriers include:

- **Unclear utility value proposition:** Many investor-owned electric utilities still view customer-sited CHP as a source of revenue erosion due to traditional business models and regulations linking cost recovery and utility revenue to electricity sales.
- **Market and nonmarket uncertainties:** CHP requires a significant capital investment and the equipment has a long life — potentially over 20 years. It can be challenging to make investment decisions in a rapidly changing policy and economic environment. Uncertainties affecting project economics include fuel and electricity prices, regional/national economic conditions, market sector growth, utility and power market regulation and environmental policy.
- **End-user awareness and economic decision-making:** CHP is not regarded as part of most end users' core business focus and, as such, is sometimes subject to higher investment hurdle rates than competing internal options. In addition, many potential project hosts are not fully aware of the full array of benefits or are overly sensitive to perceived CHP investment risks.
- **Local permitting and siting issues:** CHP installations must comply with a host of local zoning, environmental, health and safety requirements at the site. Navigating these rules requires interaction with various local agencies including fire districts, air districts and water districts and planning commissions, which may have no previous experience with a CHP project, technologies and systems.²²²

Some states such as California, New York and Connecticut have adopted policies that encourage CHP growth such as financial and other incentives to CHP projects. Table 15 shows the potential scope of CHP in Connecticut.

Table 15. Overall CHP Technical Potential in Connecticut²²³

Business Type	50-500 kW		0.5 - 1 MW		1 - 5 MW		5 - 20 MW		> 20 MW		Total	
	Sites	50-500 kW (MW)	Sites	0.5-1 MW (MW)	Sites	1-5 MW (MW)	Sites	5-20 MW (MW)	Sites	>20 MW (MW)	Total Sites	Total MW
Industrial Topping Cycle CHP	418	70	47	33	52	106	11	99	4	107	532	415
Commercial Topping Cycle CHP	2,223	235	465	213	206	207	13	116	1	28	2,907	799
WHP CHP	1	0.1	0	0	0	0	0	0	0	0	1	0.1
District Energy CHP	0	0	0	0	1	4	0	0	2	105	3	109
Total	2,642	305	512	246	259	317	24	215	7	240	3,443	1,323

iii. Production environmental compliance value/avoided costs

By reducing the demand for the electric grid in general, CHP is also able to decrease emissions from conventional generation plant and also decrease the costs of compliance. The direct emissions from CHP systems, which are most often fueled with natural gas, are low compared to coal or oil combustion for electricity. CHP technologies are capable of meeting or exceeding air quality regulations throughout the United States, including states such as California, which have

²²² U.S. DOE, 2016.

²²³ U.S. DOE, 2016.

demanding limits for NO_x, CO and VOC emissions.²²⁴

We observe that on-site emissions increase and off-site emissions decrease if a CHP system replaces separate electric and thermal energy production. Thus, customer-sited CHP can reduce environmental compliance costs of bulk power generators (utilities or IPPs), but it could increase the environmental compliance costs of the host customer. These costs and benefit shifts will manifest separately in each set of cost-effectiveness tests.

iv. Reduced reserves

By reducing demand for the electric system in general, CHP also reduces the need for reserves. This leads to reduced cost to consumers for maintaining reserves for system reliability.

v. Risk during shutdowns

CHP systems rely on the grid to both mitigate shutdowns and grid risks for facility owners. A CHP system is typically sized to meet a facility's base load thermal or electricity needs. Supplemental power from the grid would serve the facility's peak power needs on a normal basis and would provide the entire facility's power when the CHP system is down for planned or unplanned maintenance. The CHP system can mitigate grid risk because it can be configured to maintain critical facility loads in the event of an extended grid outage. According to the U.S. EPA Combined Heat and Power Partnership, in order to operate during a utility system outage, the CHP system must have the following features:²²⁵

- Black-start capability. The CHP system must have a starting system. A CHP system needs an electrical signal from either a battery or a backup generator located on site.²²⁶
- Generator capable of operating independently of the grid. The CHP electric generator must be a synchronous generator, not an induction generator, which requires the grid power signal for operation. High-frequency generators (microturbines) or direct current (DC) generators (e.g., fuel cells) need to have inverter technology that can operate independently from the grid.
- System integration with load shedding. The facility must match the size of the critical loads to the capacity of the CHP generator. These loads must be isolated from the rest of the facility's noncritical loads, which must be shut down during a grid system outage, using appropriate switchgear and control logic. The critical load isolation approach can be manual or automatic and can be configured to incorporate dynamic prioritization of load matching to the CHP system capacity.

²²⁴ U.S. DOE (2017a). Overview of CHP technologies [fact sheet]. Retrieved from:

https://www.energy.gov/sites/prod/files/2017/12/f46/CHP%20Overview-120817_compliant_0.pdf

²²⁵ U.S. EPA (2015a). *Valuing the reliability of combined heat and power*. Combined Heat and Power Partnership. Retrieved from:

https://www.epa.gov/sites/production/files/2015-07/documents/valuing_the_reliability_of_combined_heat_and_power.pdf

²²⁶ Hampson, A., and Rackley, J. (2013, September). *Guide to using combined heat and power for enhancing reliability and resiliency in*

buildings. U.S. Department of Energy. Retrieved from: [https://www.epa.gov/sites/production/files/2015-](https://www.epa.gov/sites/production/files/2015-07/documents/guide_to_using_combined_heat_and_power_for_enhancing_reliability_and_resiliency_in_buildings.pdf)

[07/documents/guide_to_using_combined_heat_and_power_for_enhancing_reliability_and_resiliency_in_buildings.pdf](https://www.epa.gov/sites/production/files/2015-07/documents/guide_to_using_combined_heat_and_power_for_enhancing_reliability_and_resiliency_in_buildings.pdf)

The additional costs for switchgear and controls for a CHP system depend on: 1) the level of control necessary and 2) the speed with which the facility needs to have the CHP system pick up the critical loads in the case of a utility power outage. Critical use facilities, such as hospitals and other facilities that provide critical infrastructure during outages, would find value in the added expense.

vi. Reduced RE obligation or RPS cost

Because CHP reduces demand for grid-supplied electricity, it necessarily reduces RE obligation or RPS cost for LSEs to the extent that load is reduced. (Customers with CHP systems are not considered LSEs and are not subject to RPS requirements.) As noted previously, in addition to reducing the RPS compliance obligation of LSEs, the electricity generated by CHP systems is eligible for RPS compliance in some states depending on their fuel source. As noted by data from the U.S. EPA Combine Heat and Power Partnership, some states have moved from renewable portfolio standards to energy portfolio standards (EPS) in an effort to recognize the value of both energy efficient technologies and renewables. The type of resources that are eligible under an RPS or EPS varies by state. Most states include renewable resources such as solar, wind, small hydropower and ocean/tidal/thermal systems, biomass and landfill gas. Some states also include advanced technologies, such as fuel cells and CHP, and are including these technologies in expanded or alternative EPS policies. Pennsylvania and Connecticut have both included energy efficiency and CHP in a separate tier in their EPSs. As of 2013, 13 states — Colorado, Connecticut, Hawaii, Massachusetts, Michigan, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Dakota, Utah and Washington — include CHP and/or waste heat recovery as an eligible resource, and Arizona explicitly includes renewable-fueled CHP systems.²²⁷

vii. Cost of metering and interconnection

As is to be expected, interconnection costs and processes vary depending on the size of the CHP project. According to a 2011 ACEEE report on state-by-state experience with CHP, interconnection costs in large projects appear to be a much smaller percentage of the total cost. Additionally, larger projects over 20 MW are often subject only to the federal interconnection standards overseen by FERC.²²⁸ Large projects can often interconnect directly to transmission lines, instead of distribution lines, with fewer vagaries for CHP developers.

By contrast, the report found, interconnection costs and process can be a significant barrier to smaller (under 5 MW) CHP systems. As of 2011, thirty-one states and DC had developed interconnection standards on how to interconnect CHP systems of varying sizes. These standards give CHP developers an official avenue to apply for interconnection with the local utility. However, notwithstanding these standards, the experience from CHP developers has been that utility interconnection processes can be cumbersome and expensive, even while adhering to the letter of state standardized processes.²²⁹

²²⁷ U.S. EPA (2013). *Energy portfolio standards and the promotion of combined heat and power*. Combined Heat and Power Partnership.

Retrieved from: https://www.energy.gov/sites/prod/files/2013/11/f4/eps_and_chp_promotion.pdf

²²⁸ Chittum and Kaufman, 2011.

²²⁹ Chittum and Kaufman, 2011.

b. Values akin to traditional bulk transmission

i. Transmission capacity costs

Like other DERs, CHP is reflected as load reduction to the bulk transmission power system. And, like other DERs, there is potential for CHP to provide targeted load reduction where it is of most use to the bulk transmission system, if the utility and/or state policies provide the right incentive signals.

CHP has value for both the bulk transmission system and the distribution system. Deployment of CHP can reduce load, such that less bulk transmission is needed. Utilities may interpret their obligation to serve CHP customers to mean that they have to have T&D (and generation capacity) in place to serve the combined full requirements of CHP customers during planned and unplanned outages of the CHP system. For this reason, CHP systems are considered by utilities to have little or no value in terms of avoided T&D capacity investment on the assumption that the system has to be sized the same, regardless of whether these customers have CHP.

There are flaws in this approach, however. First, there is no reason to assume or expect that a CHP outage will coincide with a peak period on the T&D system. Planned outages can be scheduled to avoid peaks. Unplanned outages, by their very nature, might coincidentally occur on peak, but tariffs can be designed, giving the customer the option of curtailing load instead of being served fully if that happens (likely in a lower cost rate class). The second flaw is that most balancing areas serve multiple CHP systems, and the probability that all the CHP systems simultaneously have an unscheduled outage, on peak, is quite low.

The second flaw illustrates the fact that an aggregation of CHP systems in a single balancing area will have transmission and distribution capacity value, and an aggregation of CHP systems on a single distribution system will have distribution capacity value — even if traditional system planning and valuation approaches have sometimes ignored this T&D capacity value.

There is also the potential for targeted deployment of large CHP systems, typically 20 MW and over, which can interact directly with the bulk transmission system.

FERC order 1000 suggests a framework for utilities that need to make investments in transmission infrastructure to invest in energy efficiency and non-transmission alternatives, such as CHP. FERC suggests the cost of such investments could be spread among all users of a transmission system via an interregional cost allocation method if certain benefits accrue multiple transmission system regions.²³⁰

ii. Line losses

Since CHP is generally located near the point of use, it avoids the line losses that occur when electricity moves over transmission lines. Although average line losses are regularly cited as about 7% of total electricity generated, line losses are much more pronounced as a system reaches its peak load and, in fact, grow in direct relationship to the used capacity of a system.²³¹ At peak, line losses

²³⁰ Chittum, A., Farley, K., and Elliot, R. (2013). *Utilities enjoying the benefits of CHP*, p. 4–5. ACEEE. Retrieved from: https://aceee.org/files/proceedings/2013/data/papers/6_106.pdf

²³¹ Chittum et al., 2013.

can be up to three times the size of average grid losses.²³²

iii. Enhanced bulk system reliability

CHP, like other DERs, is able to enhance bulk system reliability by virtue of decreasing the amount of load that needs to be carried over the bulk transmission system. Strategically cited CHP units can be considered in forward-looking distribution and transmission plans, which can enable some grid investments to be avoided.²³³

c. Values akin to distribution plant

i. Reduced peak: Overall peak reductions and ability to manage circuit peak reductions

CHP has long been used to help reduce system peak. Since it operates mainly at large commercial, industrial and critical infrastructure facilities, facilities that invest in CHP provide some very large demand reductions to the distribution grid.

ii. Distribution capacity costs

CHP can provide huge benefits to the distribution system, including avoiding costly upgrades, when positioned effectively. In a rate case, the Massachusetts Department of Energy Resources noted that strategically cited CHP can avoid or defer distribution and transmission system investments and reduce maintenance costs for a utility.²³⁴ In New York, Con Edison was able to avoid an expensive substation upgrade with a CHP system located near the New York Presbyterian Hospital. The CHP system provides a 7 MW-equivalent reduction at the substation during system peaks, allowing Con Edison to avoid a costly upgrade. Con Edison has deferred “multiple traditional T&D load relief capital projects” as a result of this example and other targeted distribution generation projects.²³⁵

This targeted use of CHP can help utilities to defer distribution system upgrades and to relieve congestion. Additionally, since CHP systems tend to be larger than other DERs, it can be easier for utilities to see on the system.

iii. Line losses

CHP systems are naturally located at or very near the point of consumption. This means that power does not have to travel long distances over transmission or distribution wires. As a consequence, marginal line losses are avoided. On average, 7% of energy is lost in line losses, as it travels over wires. This number is much higher, however, during system peak.

²³² Lazar, J., and Baldwin, X. (2016). *Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements*. Montpelier, VT: RAP. Retrieved from: <http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf>

²³³ Chittum et al., 2013

²³⁴ MDOER (2013, February 1). Reply Comments of the Massachusetts Department of Energy Resources (MDOER), D.P.U. Case 12-97. Retrieved from: <https://eeonline.eea.state.ma.us/DPU/Fileroom/dockets/bynumber>

²³⁵ Chittum et al., 2013, 7. Chittum citing Jolly, 2013.

The CPUC determined avoided line loss factors for CHP to be 7.7%, as shown in Table 16.²³⁶

Table 16. CPUC Scoping Memo: Line Loss Factors²³⁷

	Line Loss Factors		
	Energy Efficiency	Demand Response	CHP
North	9.7%	11.9%	7.7%
South	7.6%	11.2%	7.7%
San Diego	9.6%	6.6%	7.7%

iv. Enhanced distribution reliability

Energy reliability is often measured in duration and frequency of loss of service: how many seconds, minutes, hours or days an energy resource is down and unavailable. CHP systems can improve individual-facility-level reliability in much the same way that they improve overall system resiliency. CHP systems are more regularly maintained and used than some backup resources and as a result may have more reliable operation. Although they often use the same fuel resources as the local grid — that is, many are natural gas fired and subject to the same constraints as natural gas power plants — they provide thermal energy using this fuel source instead of more gas for a boiler or fuel oil or another commodity that must be delivered by truck. Unfortunately, data are limited on how CHP systems perform relative to local power grids, as there is no concerted effort by the CHP industry to collect performance data and compare them to performance data for area grids.²³⁸

As noted by Chittum and Relf, CHP systems can ramp up faster than many types of power generation resources, so they can begin serving loads faster and respond more quickly to changes in grid-supplied power. Further, by directly supplying local loads with power and heat, CHP systems can reduce the strain on nearby parts of the electric distribution grid. This can reduce peak stress and the chances of grid component failure.²³⁹

²³⁶ The loss factor for CHP is losses (loss rate) as a percentage of net energy for load. A line loss of 7.8% equals a loss factor of 1.084599 (or 8.4599%). The loss factor for CHP in the CPUC *Scoping Memo* represents losses or loss rate as a fraction of net energy for load and not a gross-up factor. See Wong, L. (2011). *A review of transmission losses in planning studies*. California Energy Commission. Retrieved from: <https://www.energy.ca.gov/2011publications/CEC-200-2011-009/CEC-200-2011-009.pdf>

²³⁷ CPUC Attachment I, Standardized Planning Assumptions (Part 1) for System Resource Plans R.10-05-006, p. 56. Retrieved from <http://docs.cpuc.ca.gov/efile/RULC/127543.pdf>.

²³⁸ Chittum, A. (2016). *Valuing resiliency: How should we measure risk reduction?* p. 3. ACEEE. Retrieved from: http://aceee.org/files/proceedings/2016/data/papers/11_133.pdf

²³⁹ Chittum and Relf, 2018.

CHP systems can provide black-start capability, can act as a generator acting independently of the grid and can provide system integration with load shedding, which allows the CHP system to provide backup responsibility for critical loads.²⁴⁰

SIDEBAR

Cost of power interruptions

$$\text{Cost of Power Interruptions} = \sum_{i=1}^m \sum_{j=1}^n C_{i,j} \times E_{i,j} \times O_{i,j} \times V_{i,j}$$

where,

C = total number of electric power customers in each region and customer class sector

E = the frequency of power interruption events in one year for each region and customer class sector

O = the cost per interruption as a function of outage duration by customer class for each region

V = vulnerability factor

m = the number of customers in each customer class

n = the number of regions

i,j = indices for customer class and region, respectively

Values for distribution system reliability will vary from customer to customer. But the impact of interruptions of service can be consequential. A LBNL study estimates that the power interruptions cost \$59 billion per year (in 2015 dollars) nationally.²⁴¹

An EPA study provided a methodology to determine how to quantify the cost of momentary and long-term outages to a particular facility.²⁴²

²⁴⁰ U.S. EPA (2007). *Valuing the reliability of combined heat and power*. Combined Heat and Power Partnership. Retrieved from: https://www.epa.gov/sites/production/files/2015-07/documents/valuing_the_reliability_of_combined_heat_and_power.pdf

²⁴¹ Eto, J. (2017). *National cost of power interruptions to electricity customers*. Institute of Electrical and Electronics Engineers (IEEE). Retrieved from: <http://grouper.ieee.org/groups/td/dist/sd/doc/2017-01-10%20National%20Cost%20of%20Power%20Interruptions%20to%20Electricity%20Customers%20-%20Eto.pdf>

²⁴² U.S. EPA, 2007.

d. Customer/premises value

CHP provides a range of benefits to system hosts. CHP can provide greater control over sources of energy and costs, reduce total energy consumption and energy bills and enhance the reliability and resiliency of host customers.

i. Customer choice and control

The facilities that invest in CHP usually do so because they can use both the electricity generated and the thermal load, providing customers with lower costs and much higher levels of combined efficiency. Because CHP is able to provide simultaneous electric and thermal energy, it is a highly efficient resource. CHP systems can operate at combined efficiencies of over 80%, whereas the electric generating efficiency of an average power plant is 36%. By using waste heat recovery technology to capture wasted heat associated with electricity production, CHP systems typically achieve total system efficiencies of 60% to 80%, compared to 50% for conventional power plant or on-site boiler technologies.²⁴³

Customers may also value having electric reliability with on-site generation. CHP is ideal for applications that require constant energy. The efficiencies realized from CHP in these situations can reduce costs to the customer — so there are cost advantages. CHP for these customers also added commercial value given the assurance of electric reliability in the event of grid failure.

ii. Reduced bills

CHP reduces energy bills because of its higher efficiency than the resources it replaces. This means that a utility or industrial facility needs to spend less money on fuel costs than it would otherwise incur. As a result, on average a large gas-turbine-based CHP system has a levelized cost of about 6.0 cents/kWh or less, while CHP systems powered by biomass and biogas have levelized costs of well below 4.0 cents/kWh. Typical levelized costs of a natural gas combined cycle plant ranges from 6.9 to 9.7 cents/kWh.²⁴⁴ Thus biogas- or biomass-fueled CHP can help reduce power costs by between 2.9 and 5.7 cents per kWh, and natural-gas-fueled CHP can reduce power costs by between 0.9 and 3.7 cents per kWh.

The efficiency can result in less fuel being required for a given unit of energy output. By using waste heat recovery technology to capture and use heat that is otherwise wasted during electricity production, CHP systems typically achieve total system efficiencies of 60 to 80 percent, compared to just 50 percent total system efficiency for conventional technologies (i.e., purchased utility electricity and an on-site boiler). This efficiency can result in less fuel being required for a given unit of energy output, and less fuel used can in turn can reduce energy bills.²⁴⁵ An additional advantage is that because less electricity is purchased from the grid, facilities have less exposure to rate increases. The inherent flexibility in CHP systems provides facilities with fuel-switching

²⁴³ U.S. DOE (undated-c). *Benefits of combined heat and power*. Retrieved from: <https://le.utah.gov/interim/2017/pdf/00002957.pdf>

²⁴⁴ Chittum et al., 2013, 9.

²⁴⁵ U.S. DOE, undated-c.

capabilities to hedge against high fuel prices, as CHP systems can be configured to operate on a variety of fuel types, such as natural gas, biogas, coal and biomass.²⁴⁶

iii. Reduced overall energy usage

CHP is a valuable energy efficiency resource and consequently is widely used to meet state energy efficiency goals. In Massachusetts, the 2008 Green Communities Act requires that all cost-effective CHP must be acquired by utilities within their energy efficiency programming.²⁴⁷ Massachusetts also includes performance incentives for energy efficiency. Since CHP was, on average, the lowest cost resource, it was responsible for about 30% of Massachusetts utilities' energy efficiency targets in 2011. As a result, CHP was one of the largest contributing factors in the overall lifetime cost of saved energy decreasing from \$0.022 in 2010 to \$0.016 in 2011.²⁴⁸

The overall total efficiency of a CHP system, as shown in Figure 29, and the efficiency that can be achieved, depends upon the type of technology and fuel source for the CHP.

Figure 29. Efficiencies of Different CHP Systems²⁴⁹

Not every CHP system operates at the same total system efficiency. A CHP system's efficiency depends on the technology used to generate the electricity and thermal energy, the system design, and how much of the thermal energy is used by the site. The most common prime movers include:

- Steam Turbine: 80% efficiency
- Diesel Engine: 70%-80% efficiency
- Natural Gas Engine: 70%-80% efficiency
- Gas Turbine: 70%-75% efficiency
- Microturbine: 65%-75% efficiency
- Fuel Cell: 65%-80% efficiency

²⁴⁶ U.S. DOE, undated-c.

²⁴⁷ Chittum et al., 2013.

²⁴⁸ Chittum et al., 2013, 11: quoting MassSave2012. As a result of the savings level achieved, Massachusetts utilities earned a performance incentive equal to about 5% of their energy efficiency spending.

²⁴⁹ U.S. EPA (2015b). *Combined heat and power: A guide to developing and implementing greenhouse gas reduction programs*. Local Government Climate and Energy Series. Retrieved from: <https://www.epa.gov/sites/production/files/2015-08/documents/chpguide508.pdf>

iv. Resilience benefits

CHP systems can be capable of islanding and provide resilience benefits for system owners and also for the grid as a whole. For the customer, the configuration of the system offers resilience benefits because CHP systems are located closer to the consumption site than traditional centralized generation. According to Chittum and Relf, “this improves energy resiliency because power moves over shorter distances, reducing the likelihood that it will be interrupted by tree limbs or debris falling on electric distribution and transmission lines.”²⁵⁰

CHP systems are typically well maintained because they provide power and heat to connected facilities under normal operating conditions and are therefore run regularly. As a result, they have performed better than other types of backup generation in emergencies, as other types of backup generation are not generally as well maintained and not used often.²⁵¹ There are resilience benefits from CHP systems reliability to the customer facility and to society as a whole, and those can be analytically separated. An industrial facility can continue to operate during a grid failure, providing that facility with both resilience and reliability benefits.

CHP offers resilience benefits to the grid as a whole. Chittum and Relf note that “by directly supplying local loads with power and heat, CHP systems can reduce the strain on nearby parts of the electric distribution grid. This, in turn, alleviates stress on the system and reduces the chances of individual grid component failure.”²⁵²

e. Societal/public value

i. Resilience and reliability benefits to society as a whole

CHP can mitigate the impacts of an emergency by keeping critical facilities running without any interruption in electric or thermal service. If the electricity grid is impaired, a specially configured CHP system can continue to operate, ensuring an uninterrupted supply of power and heating or cooling to the host facility. Following Hurricane Sandy, the New York State Energy Research and Development Authority (NYSERDA) conducted an analysis of the operation of CHP systems at sites that had received NYSERDA funding and were located in areas affected by the storm. Among the sites that lost grid power, and where the CHP unit was designed to operate during a grid outage, all of the CHP systems performed as expected.²⁵³

ii. Health impacts

The main health impacts from CHP are similar to those from other energy efficiency and DG investments, namely, avoided generation from other sources that are not as efficient or with greater emissions. Emissions of SO₂, NO_x, particulate matter and mercury have verified negative impacts on public health, and technologies such as CHP, energy efficiency and DG investments that reduce

²⁵⁰ Chittum and Relf, 2018.

²⁵¹ Chittum and Relf, 2018.

²⁵² Chittum and Relf, 2018.

²⁵³ Hampson, A., Bourgeois, T., Dillingham, G., and Panzarella, I. (2013). *Combined heat and power: Enabling resilient energy infrastructure for critical facilities*. ICF International. Prepared for Oak Ridge National Laboratory. Retrieved from: https://www.energy.gov/sites/prod/files/2013/11/f4/chp_critical_facilities.pdf

or avoid these emissions will help public health.²⁵⁴ For CHP, the magnitude of the health impacts will depend in large part on the type of CHP system and the type of fuel it uses. It's therefore hard to extrapolate generic health impacts.

A specific example can show the estimated health and societal benefits of a 15 MW CHP system in the Northeast of the United States. This analysis assumed that the system resulted in a 25% reduction in overall fuel consumption compared to traditional energy systems. As Table 17 shows, there are significant annual health and medical cost savings from reduced overall energy consumption related to CHP installations.

Table 17. Projected Health and Societal Benefits of a 15 MW CHP System in Massachusetts²⁵⁵

	Incidents Per Year	Societal Value ¹¹	Direct Medical Costs ¹²
Premature Death	0.13	\$850,361	\$37,709
Chronic Bronchitis	0.08	\$37,896	\$9,695
Hospital Visit Incidents	0.11	\$1,498	\$1,195
Asthma Attacks	2.58	\$156	\$148
Respiratory Symptoms	123.21	\$4,481	\$4,481
Work Loss Days	22.73	\$4,136	\$3,847
Mercury Related	N/A	\$39,777	\$39,777
Totals		\$938,305	\$96,852
Unintended Impacts/kWh:		\$0.0333	\$0.0034

iii. Air quality improvements

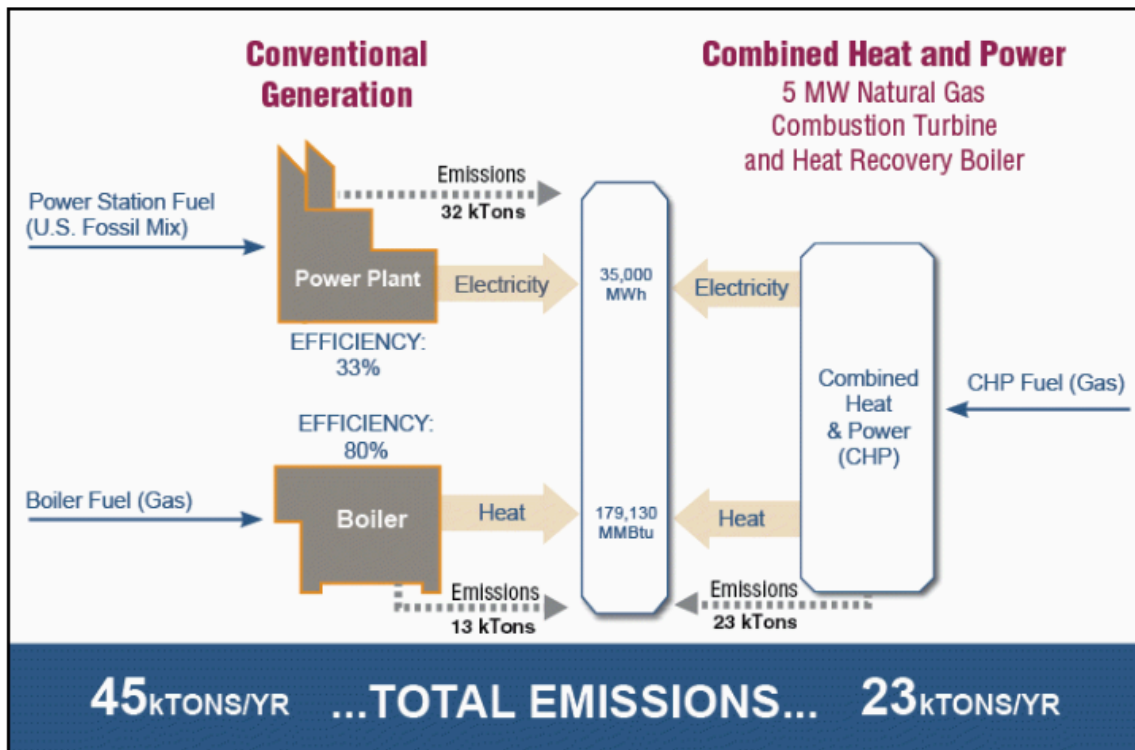
CHP technologies offer significantly lower emissions rates compared to separate heat and power systems. The primary pollutants from gas turbines, which power many CHP units, are oxides of nitrogen (NOx), carbon monoxide (CO) and volatile organic compounds (VOCs) (unburned, nonmethane hydrocarbons). Other pollutants such as oxides of sulfur (SOx), particulate matter (PM), and carbon dioxide emissions which vary depending on the fuel used.²⁵⁶

It should also be noted, however, that emissions from small-scale, distributed generation tend to come from much shorter smokestacks and have different (usually worse) impacts, especially for particulates, than emissions from much taller central station smokestacks. This will vary depending on the fuel type used, the system design and even the geographic location. Figure 30 shows a comparison of emissions.

²⁵⁴ Belden, A., Veilleux, N., Crowe, J., and Wright, K. (2013). *Powering the future of healthcare: A combined heat and power guide for Massachusetts hospital decision makers*. Health Care Without Harm. Retrieved from: https://www.greenribboncommission.org/archive/downloads/CHP_Guide_091013.pdf

²⁵⁵ Belden et al., 2013.

²⁵⁶ U.S. EPA (2015c). *Catalog of CHP technologies*. Combined Heat and Power Partnership. Retrieved from: https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_1_introduction.pdf

Figure 30. Conventional Generation vs. CHP: CO₂ Emissions²⁵⁷

This diagram illustrates the CO₂ emissions output from electricity and useful thermal energy generation for two systems: (1) a fossil fuel-fired power plant and a natural gas-fired boiler; and (2) a 5 megawatt combustion-turbine CHP system powered by natural gas. The separate heat and power system emits a total of 45 kilotons of CO₂ per year (13 kilotons from the boiler and 32 kilotons from the power plant), while the CHP system, with its higher efficiency, emits 23 kilotons of CO₂ per year.

The EPA estimates that a 10 MW CHP natural gas unit yields 42,506 tons of CO₂ savings and 87.8 tons of NO_x annually.²⁵⁸

In Table 18, the International District Energy Association provides estimates of GHG emission reductions from a variety of resources, including CHP.

²⁵⁷ U.S. EPA (undated). CHP benefits [web page]. Combined Heat and Power Partnership. Retrieved from:

<https://www.epa.gov/chp/chp-benefits>

²⁵⁸ U.S. EPA (2015d). *Combined heat and power: Frequently asked questions*. Combined Heat and Power Partnership. Retrieved from:

https://www.epa.gov/sites/production/files/2015-07/documents/combined_heat_and_power_frequently_asked_questions.pdf

Table 18. Fossil Fuel Consumption and GHG Emissions From a Range of Generation Resources²⁵⁹

		Fossil fuel consumption (Btu/kWh)	GHG emissions (metric tons/MWh)
Fossil and Nuclear power-only	Conventional Coal	8,784	0.82
	Conventional NGCC	6,967	0.37
	Nuclear	-	-
	Advanced Coal with CCS *	10,434	0.11
	Advanced NGCC with CCS *	7,521	0.04
Renewable power-only	Biomass	-	-
	Onshore Wind	-	-
	Offshore Wind	-	-
	Solar Thermal	-	-
	Large Photovoltaic	-	-
CHP	Waste heat to power	-	-
	Biomass CHP 22 MW	(767)	(0.43)
	NG engine CHP 2.5 MW	5,292	0.28
	NG engine CHP 5 MW	5,195	0.28
	NG CC CHP 20 MW	4,492	0.24

* Note: CCS is not a proven technology.

iv. Water quality improvement

CHP does not offer water quality improvement per se, but it reduces water use significantly to the extent that the CHP system is avoiding large thermal plant production. Water usage will vary greatly by location, size and type of CHP unit, type of fuel used for the CHP system and even time of day. The Department of Energy and the Environmental Protection Agency estimate that the use of small- and medium-sized natural-gas-fueled CHP in Texas reduces water use by 90%, compared to the average power plant's water use in Texas.²⁶⁰

²⁵⁹ IDEA (2013). *Combined heat and power (CHP): Essential for a cost effective clean energy standard*. International District Energy Association. Retrieved from: https://www.energy.gov/sites/prod/files/2013/11/f4/chp_clean_energy_std.pdf

²⁶⁰ Summit Blue Consulting, LLC (2008). *Combined heat and power in Texas: Status, potential, and policies to foster investment*. Prepared for Texas Public Utility Commission. Retrieved from: https://www.puc.texas.gov/industry/projects/electric/38578/Combined_Heat_Power_Texas.pdf

v. Employment and local economic impacts

The use of CHP systems creates direct jobs in manufacturing, engineering, installation and ongoing operation and maintenance, and it supports jobs and economic activities for associated thermal uses. Further, like any industry, CHP projects create indirect jobs in the CHP industry's supply chain and other supporting industries. According to the DOE *U.S. Energy and Employment*

The use of CHP systems creates direct jobs in manufacturing, engineering, installation and ongoing operation and maintenance, and it supports jobs and economic activities for associated thermal uses.

Report, CHP generation technologies employ at least 18,034 workers, or about 2% of the electric power generation technology mix.²⁶¹

In addition, NRDC suggests that each GW of installed CHP capacity may be reasonably expected on net to create and maintain between 2,000 and 3,000 full-time equivalent jobs throughout the lifetime of the system. These jobs would include direct jobs in manufacturing, construction, and

operation and maintenance, as well as other indirect jobs (net of losses in other sectors), both from redirection of industrial energy expenditures and re-spending of commercial and household energy-bill savings.²⁶²

Appendix E: Fuel Cell Power Generation

1. Background

A fuel cell is an electrochemical device that uses hydrogen from a fuel source and oxygen from the air to produce electricity, with water and heat as its by-products.²⁶³ Hydrogen can be sourced from fossil fuels, such as natural gas, or renewables. Hydrogen can also be produced by water electrolysis, which can be powered by electricity from renewables or from other generators and the grid. Unlike other electrochemical devices, such as batteries, a fuel cell does not run down or require recharging. It will produce energy as long as fuel is supplied.

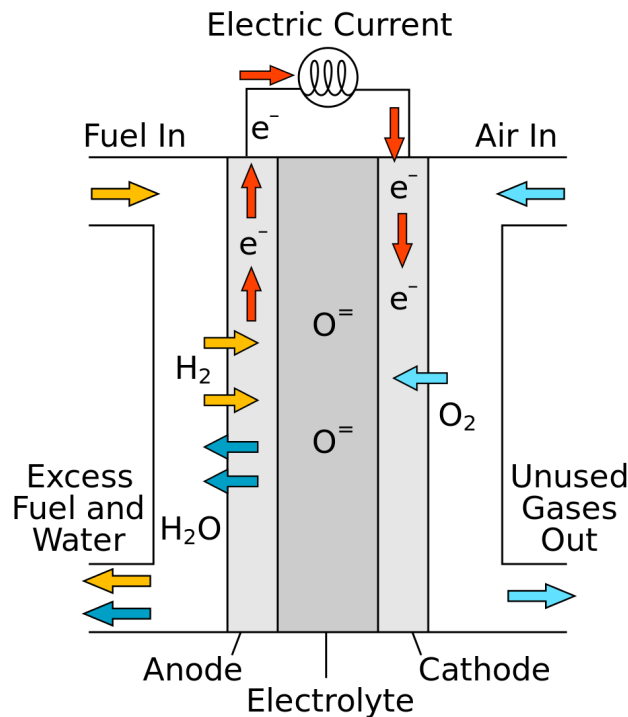
²⁶¹ U.S. DOE (2017b). *U.S. energy and employment report*. Retrieved from:

https://www.energy.gov/sites/prod/files/2017/01/f34/us_energy_jobs_2017_final.pdf

²⁶² Gowrishankar, V., Angelides, C., and Druckenmiller, H. (2013). *Combined heat and power systems: Improving the energy efficiency of our manufacturing plants, buildings, and other facilities*. NRDC Issue Paper. Retrieved from: <https://www.nrdc.org/sites/default/files/combined-heat-power-IP.pdf>

²⁶³ U.S. DOE (2018, January). *State of the states: Fuel cells in America 2017*. Retrieved from:

https://www.energy.gov/sites/prod/files/2018/06/f53/fcto_state_of_states_2017_0.pdf

Figure 31. Diagram of a Fuel Cell²⁶⁴

Fuel cells are operated at a fixed location for primary power, backup power or CHP. The benefits that encourage their adoption include:²⁶⁵

- Emission reduction in the power sector;
- Reliable power generation, increased resilience in face of extreme weather; and
- Highly efficient power generation, which can use waste heat from energy production to provide heating, cooling and hot water.

Fuel cell use spans market sectors from corporate data centers and industrial facilities to retail stores. It is possible to use fuel cells to bypass grid power and generate power on-site with renewables. Fuel cells can be installed for backup power at sensitive industrial and public facilities or to serve communities in microgrids. Installed at customers' sites, some fuel cell systems could save energy costs.²⁶⁶ Many fuel cell customers are entering into power purchase agreements (PPA), which are long-term contracts to buy energy at a fixed price. This also reduces market risk and hedges wholesale price volatility. Fuel cell systems are commonly used for backup power because of high reliability, long run-time and little maintenance required.

²⁶⁴ Wikimedia Commons. Retrieved from: https://commons.wikimedia.org/wiki/File:Solid_oxide_fuel_cell.svg

²⁶⁵ U.S. DOE, 2018, 3.

²⁶⁶ Wood, E. (2017, April 20). Three ways fuel cell microgrids lower energy cost [web page]. Microgrid Knowledge. Retrieved from: <https://microgridknowledge.com/fuel-cell-microgrids-lower-energy-cost/>

Table 19 shows the generalized benefits of on-site fuel cell power generation.

Table 19. Fuel Cell Benefits — Stationary and Backup Power²⁶⁷

	On-Site Power Generation	
	Large Stationary Power: <i>Buildings, Data Centers, Utilities</i>	Small Stationary Power: <i>Telecom Towers, Traffic Signals, Off-Grid Equipment</i>
Savings	Fuel costs Low water usage	Capital and operational savings
Reliability / Efficiency	High reliability – 99.9999% Meets stringent availability standards for data centers Continuous power production when grid goes down High-grade power without voltage sags or surges Byproduct heat can be recovered for use – hot water, facility heating, even cooling	High reliability Maintains performance in extreme hot or cold temperatures Longer runtimes than batteries, generators Reduced reporting and spill mitigation requirements
Low-to-Zero Emissions	Exceptionally low using natural gas, zero-emissions using biogas, hydrogen Exempt from air permitting requirements in California, other states	Zero-emissions
Scalable	Meets any need – can be scaled from kilowatts (kW) to multi-megawatts (MW) Can supply power to electrical grids (largest installation to date is 59 MW)	Can be scaled in size to any application
Compactness / Easy Siting	Small footprint Can be sited on roofs, in basements, indoors, outside Quiet operation	Compact footprint Can be sited on roofs, rugged terrain Quiet operation
Fuel Flexibility	Natural gas, biogas, hydrogen, gasified biomass	Hydrogen, methanol, natural gas

²⁶⁷ Gangi, J., Dolan C., Lewis, J., and Doughty, B. (2018). *Harnessing American power: Fuel cell impact enabled by R&D;*

A snapshot of fuel cells in municipal applications. Fuel Cell & Hydrogen Energy Association. Retrieved from:

<https://static1.squarespace.com/static/53ab1feee4b0bef0179a1563/t/5b55d266575d1f8f7c1ada42/1532351079475/Business+Case.pdf>

2. Studies on the value of fuel cells

Fuel cells have as many common features as the other types of distributed generation; the utility system (generation, transmission, distribution) layer cake value for fuel cells is virtually the same as that of CHP or DG. Because fuel cells are deployed less often than other types of DG, the value of fuel cells has been examined less often. It is helpful to review the results of some of the limited number of studies on the value of fuel cells.

a. California distributed fuel cell values

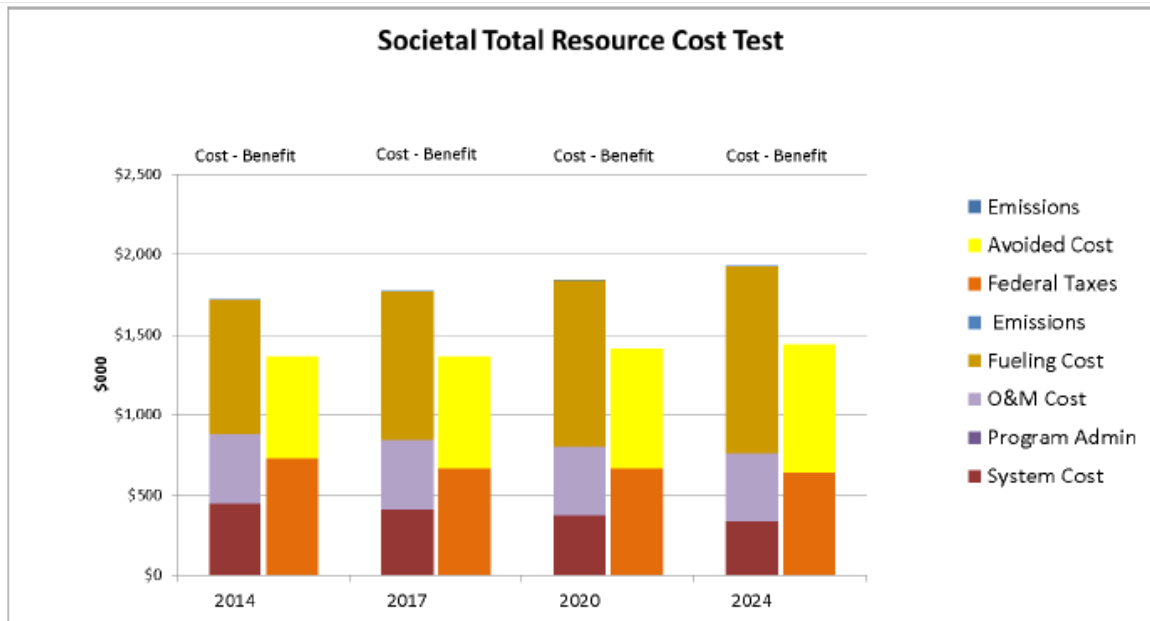
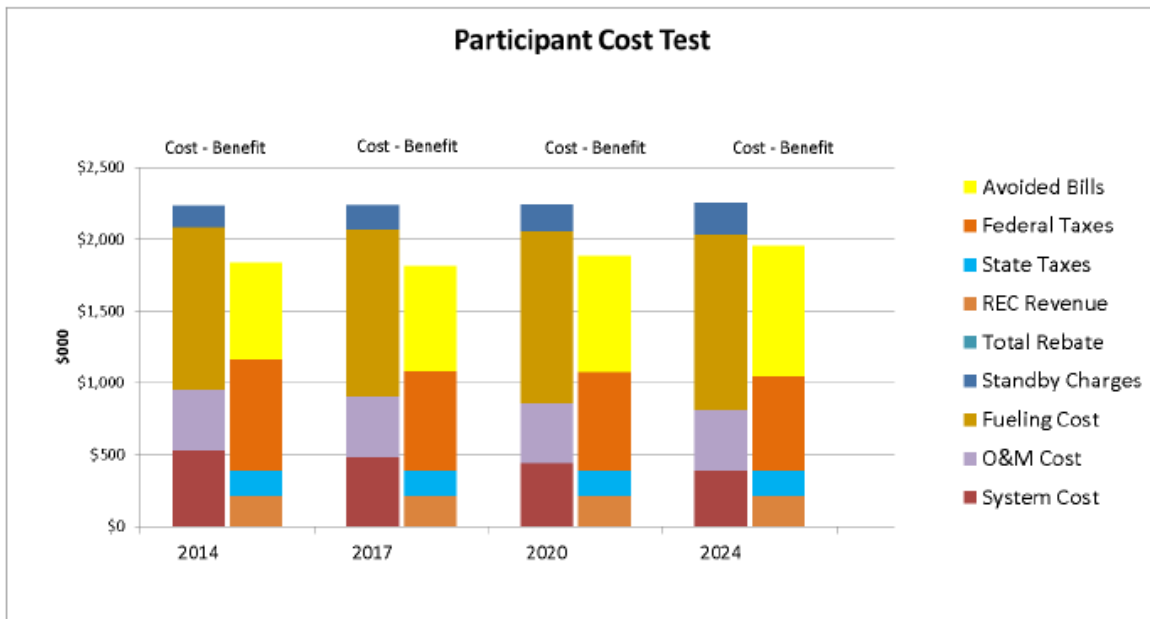
California has committed to support stationary fuel cells, especially under the Energy Commission's SGIP (Self-Generation Incentive Program), which provides state incentives to DG resources within California. Since 2001, SGIP has funded more than 175 MW of stationary fuel cells, with 23.4% of the total being fuel cell CHP.²⁶⁸ In 2015, a cost-effectiveness study was completed by Itron, on behalf of PG&E and the SGIP working group, to assess the technologies incentivized under the program.²⁶⁹ The Itron study uses the SGIP cost effectiveness model (SGIPce), which incorporates technology, global, IOU rates and other inputs. The avoided cost values are derived from E3's 2013 NEM avoided cost calculator, for which the following benefits are included in the societal cost test:²⁷⁰

- Avoided utility system related costs
 - Avoided line losses
 - Avoided purchase of energy commodity and resource adequacy costs
 - Avoided T&D costs
 - Avoided emissions (CO₂, NO_x and PM emissions)
 - Avoided transportation of natural gas due to CHP systems
- Market transformation effects
- Reliability benefits (both system and customer ancillary services)
- Tax credit/depreciation.

²⁶⁸ Self-Generation Incentive Program. SGIP program statistics. Last updated May 14, 2019. Retrieved from: <https://energycenter.org/self-generation-incentive-program/program-statistics>

²⁶⁹ Itron (2015, October). *Self-Generation Incentive Program cost effectiveness study*. Prepared for PG&E and the SGIP Working Group. Retrieved from: <http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889>

²⁷⁰ The detailed inputs and results concerning each layer of avoided costs are not available in this report. Note that the Societal Total Resource Cost Test is a hybrid test between the TRC and SCT and includes some but not all societal benefits.

Figure 32. Representative STRC Test for a Directed Biogas 1,200 kW CHP Fuel Cell²⁷¹**Figure 33. Representative PCT for a Directed Biogas 1,200 kW CHP Fuel Cell²⁷²**²⁷¹ Itron, 2015, 6–39.²⁷² Itron, 2015, 6–92.

The California review of fuel cell technologies indicated a STRC B/C ratio of between 0.6 and 0.8 because large capital, fueling and O&M costs outweigh the social benefits.²⁷³ Fuel cell CHP operating on renewable sources tends to have better participant cost test results but is still not cost effective without the SGIP incentive. Since 2016, the SGIP incentives have been largely directed to other distributed technologies, such as energy storage, partly because fuel cells are not cost effective.²⁷⁴ The current SGIP for fuel cells is \$0.6/watt, with another \$0.6/watt biogas adder, which will be prorated based on minimum renewable fuel blending requirements. In addition, incentives will decrease on a step basis, depending on the generation installed.²⁷⁵

In 2011, the National Fuel Cell Research Center did a cost-effectiveness analysis of stationary fuel cells in distributed energy markets in California,²⁷⁶ ranging in size from several kW to several MW, which yields very different conclusions. The study assesses four possible combinations of fuel and operating mode for each of eight fuel cell products included in the analysis:

- Natural gas, with or without cogeneration/CHP.
- Renewable fuel, with or without cogeneration/CHP.

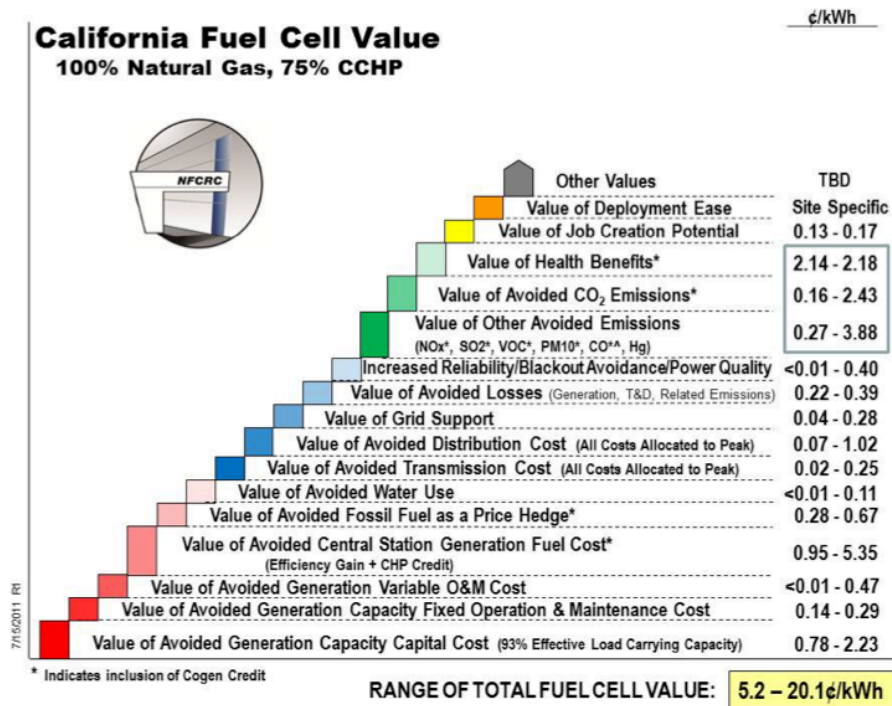
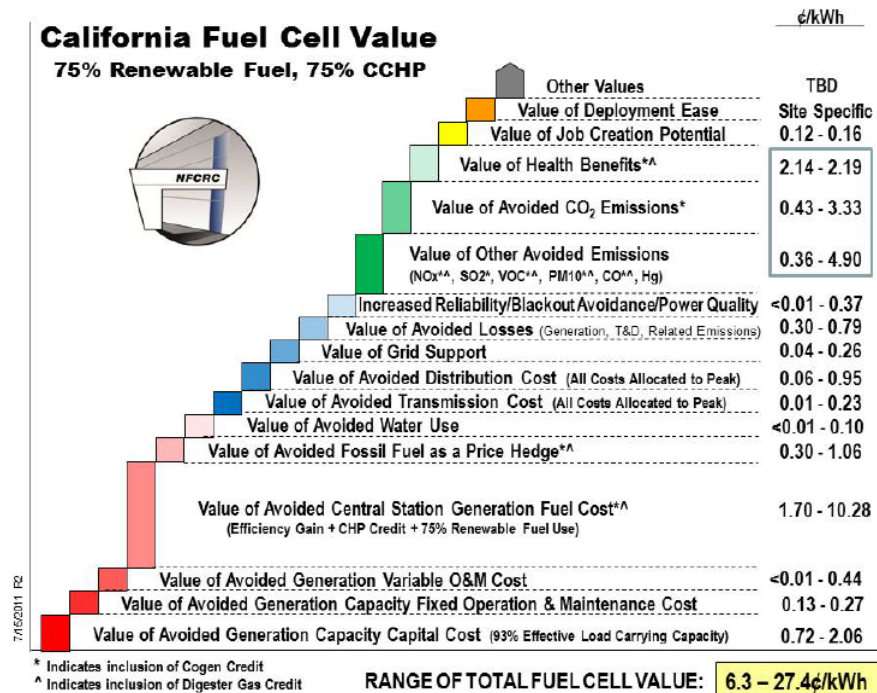
The methodology is based on CPUC's *Standard Practice Manual* with three benefit cost tests performed: the participant test, the RIM test and the societal test. The avoided cost values are quantified by using market prices of equipment, service and other factors; some other values are derived from a literature search. The fuel cell cost and performance data over the lifetime of the project are collected by participating organizations. Figures 34 and 35 show the California fuel cell value.

²⁷³ For a comparison of societal total cost test results across SGIP technologies, see Itron, 2015.

²⁷⁴ St. John, J. (2016, March 16). CPUC staff to Bloom Energy: Your fuel cells shouldn't get state incentives. GTM Research. Retrieved from: <https://www.greentechmedia.com/articles/read/cpuc-staff-to-bloom-energy-your-fuel-cells-shouldnt-get-state-incentives#gs.9yS7WMY>

²⁷⁵ For more details on SGIP incentive rates, see PG&E (undated). Discover the Self-Generation Incentive Program for non-residential customers [web page]. Retrieved from: https://www.pge.com/en_US/business/solar-and-vehicles/your-options/solar-programs/self-generation-incentive-program/self-generation-incentive-program.page

²⁷⁶ NFCRC (2011, July 14). *Build-up of distributed fuel cell value in California: 2011 update background and methodology*. Irvine, CA: UCI Advanced Power & Energy Program, National Fuel Cell Research Center. Retrieved from: http://www.casfcc.org/PDF/Fuel_Cell_Value-Methodology_2011_FINAL_072411_Large-Units_Final.pdf

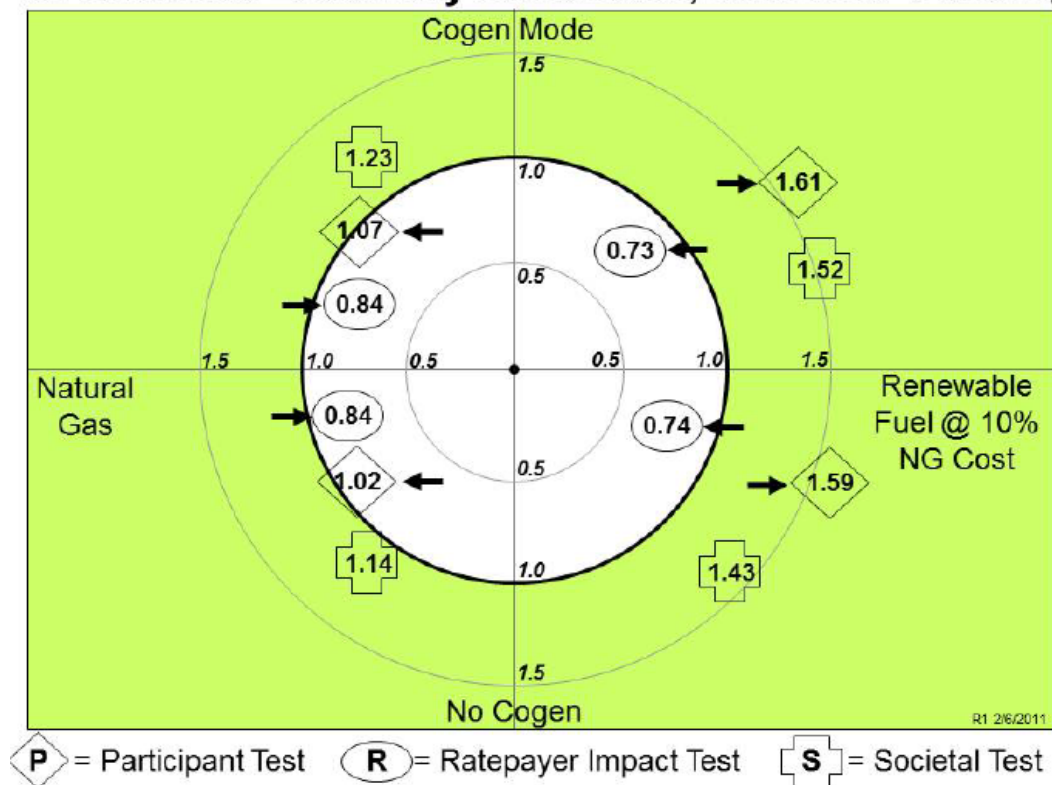
Figure 34. California Fuel Cell Value – 100% Natural Gas, 75% CCHP Mode²⁷⁷Figure 35. California Fuel Cell Value – 75% Renewable Fuel, 75% CCHP Mode²⁷⁸²⁷⁷ NFCRC, 2011, 4.²⁷⁸ NFCRC, 2011, 5.

A fuel cell fueled 100% with natural gas and operated in CCHP (or Combined Cooling, Heat and Power) mode 75% of the time contributes up to 20.1 cents/kWh of fuel cell electricity. This value increases to up to 27.4 cents/kWh if the same fuel cell is fueled primarily with renewable digester gas, with natural gas as backup fuel only.

These results for avoided costs are then incorporated into a benefit-cost analysis of DG stationary fuel cells in California. In this study, the weighted average benefit values exceed costs for all configurations under the participant test and the societal cost test. The upper values are achieved in societal benefit-cost tests capturing the value of avoided CO₂ emissions, health benefits and job creation, which are quite significant. Total lifetime benefits and costs are compared by calculating benefit-cost ratios. Two scenarios are developed to reveal that SGIP ratepayer-funded incentives effects with the SGIP funding are an intrasocial transfer, so there is no net societal impact.

Figure 36. Weighted Average Benefit Cost Ratios with SGIP Funding²⁷⁹

Stationary Fuel Cells in California: Benefit-Cost Ratios for Baseload Electricity Generation, With SGIP Funding



²⁷⁹ NFCRC, 2011, 10.

b. New York fuel cell (stationary) program

New York state has set up ambitious goals in its Reforming the Energy Vision (REV) strategy: Achieve 40% GHG emissions reduction from the 1990 level and increase renewable generation share to 50% of the state's electricity consumption by 2030. The 10-year, \$5 billion Clean Energy Fund (CEF) is a core component of REV to enable this transition.

CEF, administrated by NYSERDA, aims to build a clean, resilient and affordable energy system by accelerating the use of clean energy and energy innovation while driving economic development and reducing ratepayers' bill.²⁸⁰ A total of \$15 million is available for two years until December 31, 2019, for a stationary fuel cell program. Incentives are divided into two categories: base incentives and bonus incentives. Stationary fuel cell systems supporting critical infrastructure will receive the highest amount of bonus incentives. Systems capable of grid independent operation and providing backup power during outages will also receive incentives.

The total incentive cap for a single project is \$1 million.

Table 20. Fuel Cell Program Incentives in New York State²⁸¹

	Total Base Incentives		Bonus Incentives			
Incentive Category	Base Incentive	Grid Independent Incentive	Downstate Differential Incentive	Target Zone Incentive	Critical Infrastructure Incentive	Community Microgrid Incentive
Amount	\$1,000/kW of installed capacity	Additional \$500/kW of installed capacity	Additional 10% of the total base incentive	Additional 25% of the total base incentive	Additional 25% of the total base incentive	Additional 25% of the total base incentive
Requirements	Operate in parallel with the electric grid	Standalone capability or Islanding capacity	Installation in New York City and Westchester County	Installation in CHP Target Zones established by Consolidated Edison	Installation supports critical infrastructure of the state	Installation supports community microgrid

²⁸⁰ NYSERDA (undated-a). Clean Energy Fund [web page]. New York State Energy Research and Development Authority. Retrieved from: <https://www.nyserda.ny.gov/About/Clean-Energy-Fund>

²⁸¹ Summarized based on CEF stationary fuel cell program opportunity notice. (PON)3841.

The eligibility of fuel cell systems includes:²⁸²

- Single project size must be greater than 25 kW.
- Intended operating capacity factor should be at least 50% or above.
- Intended minimum total system efficiency of 45% should be based on higher heating value.
- The generated electricity must be primarily consumed on-site.
- The project must be located in New York state and pay into the system benefits charge.

As of March 2018, there were 24 NYSERDA-funded stationary fuel cell systems, representing 7.1 MW. Twelve additional projects with a total capacity of 2.5 MW are under development.²⁸³ The assumed 8 MW of fuel cell deployment through initiative completion (2019) are estimated to produce:²⁸⁴

- Annual energy savings of 66,580,000 kWh and lifetime energy savings of 1.3 billion kWh;
- Annual CO₂ emission reductions of 7,502 metric tons and lifetime CO₂ emission reductions of 150,000 metric tons; and
- Annual customer bill savings of \$5.99 million and lifetime bill savings of \$119.8 million.

c. New Jersey Clean Energy Program

New Jersey's Clean Energy Program (NJCEP) has offered customer incentives focused on energy savings and environmental protection dating back to 2001. Under this program, the CHP incentive effective on July 1, 2018, now offers \$350/kW to fuel cells with heat recovery. The incentive is capped at 30% of total cost or \$3 million per project. There is a 10% incentive bonus for systems installed at critical facilities with black-start and islanding capability. Fuel cells powered by renewables are eligible as a Class I renewable fuel source, which can receive up to a 30% incentive bonus, depending on the fuel mix.²⁸⁵

In 2016, several consulting companies jointly performed a CHP and fuel cell evaluation study for the New Jersey Board of Public Utilities.²⁸⁶ Their analysis is based on application data of 14 fuel

²⁸² NYSERDA (undated-b). Fuel cell (stationary) program [web page]. New York State Energy Research and Development Authority.

Retrieved from: <https://www.nyserdera.ny.gov/All-Programs/Programs/Stationary-Fuel-Cell-Program>

²⁸³ NYSERDA (2018, May 8). NYSERDA announces \$15 million available for fuel cell systems to support critical infrastructure facilities [web page]. New York State Energy Research and Development Authority. Retrieved from: <https://www.nyserdera.ny.gov/About/Newsroom/2018-Announcements/2018-05-03-NYSERDA-Announces-15-Million-Available-for-Fuel-Cell-Systems>

²⁸⁴ Note the savings from renewable energy are to be tracked and reported. NYSERDA (2018). *Clean Energy Fund quarterly performance report through June 30, 2018*. Retrieved from: <https://www.nyserdera.ny.gov/About/Publications/Program-Planning-Status-and-Evaluation-Reports/Clean-Energy-Fund-Reports>. See 2018 quarter 2 report, table 90, p. 106.

²⁸⁵ Rutgers CEEP (2018). Combined heat & power [web page]. Retrieved from: <http://www.njcleanenergy.com/commercial-industrial/programs/combined-heat-power/combined-heat-power>

²⁸⁶ ICF International, Rutgers CEEP, RU LESS, and TRC Solutions (2016, June 23). *CHP and fuel cell evaluation study for New Jersey: Phase I*. Prepared for New Jersey Board of Public Utilities. Retrieved from: [http://www.njcleanenergy.com/files/file/Library/NJCEP%20CHP%20%20FC%20Evaluation_REV%20FNL_%2006_23_17%20\(2\).pdf](http://www.njcleanenergy.com/files/file/Library/NJCEP%20CHP%20%20FC%20Evaluation_REV%20FNL_%2006_23_17%20(2).pdf)

cells without heat recovery submitted to NJCEP from January 1, 2012, to June 30, 2016. Some of the avoided cost assumptions can be found in Appendix B of that report.²⁸⁷

The results for each of the five benefit-cost tests applied are listed below in Table 21. Because of limited data on actual operating systems, the analysis used anticipated costs and benefits as inputs, to be further addressed in a Phase II study.

Table 21. Results for Five CBA Metrics for Fuel Cell Applications²⁸⁸

Project	TRC	Societal	Participant	RIM	Program Admin.
A	0.27	0.82	0.90	0.30	1.02
B	0.24	0.72	0.72	0.33	1.33
C	0.24	0.72	0.72	0.33	1.33
D	0.21	0.66	0.73	0.30	0.86
E	0.24	0.69	0.73	0.34	0.97
F	0.21	0.66	0.73	0.30	0.86
G	0.25	0.72	0.83	0.30	0.99
H	0.21	0.66	0.73	0.30	0.86
I	0.17	0.50	0.60	0.29	0.84
J	0.21	0.66	0.73	0.30	0.86
K	0.24	0.69	0.79	0.31	1.03
L	0.23	0.66	0.74	0.31	1.09
M	0.21	0.60	0.67	0.32	1.16
N	0.21	0.61	0.64	0.34	1.45

These results, which showed in almost every case that the installations were not cost effective, led the NJCEP to suspend fuel cells without heat recovery from participation in the program but left the window open for fuel cells that could recover heat and offset thermal load. This decision, drawn from prescreening evaluation and simple payback methodology, was questioned by the National Fuel Cell Research Center (NFCRC), who said “this process is not based on measured performance data of fuel cell systems leading to incorrect value for lifetime, capacity factor and emission rates.”²⁸⁹ The analysis does not evaluate the electric system as a whole, in many cases, and the assumptions do not reflect the actual specifics of the projects, such as the form of financing, the

²⁸⁷ ICF International et al., B1–B11.

²⁸⁸ ICF International et al., ix–x.

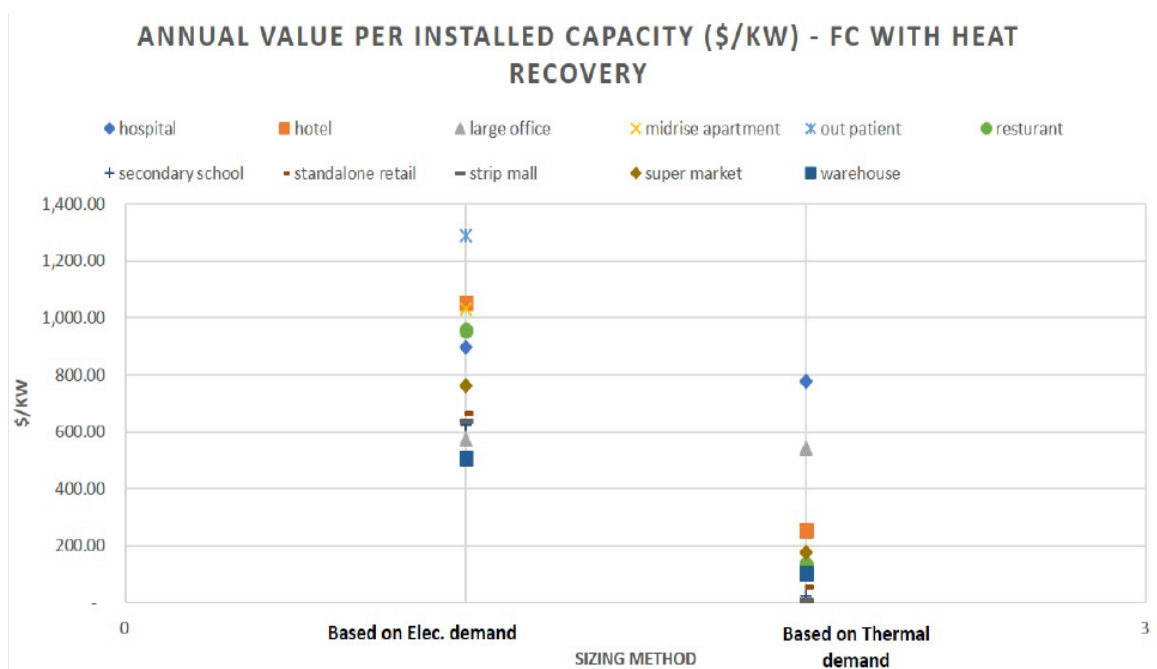
²⁸⁹ Re: Proposed revisions to NJCEP protocols (2018, May 31). New Jersey Gas Company review [letter]. Retrieved from: http://njcleanenergy.com/files/file/public_comments/FY18/Binder2Protocols.pdf

impact of federal investment tax credit incentives, the value of resiliency to a customer and other locational benefits of DG technologies to the system.

A consultant was asked to develop an operational model to evaluate how actual use can impact efficiency and cost effectiveness across different technologies. The team investigated two operational values: bill savings and resiliency in 11 facilities. The initial findings were that:²⁹⁰

- Fuel cells without heat recovery are not cost effective in most cases. However, the payback time and effectiveness may be improved in the facilities with low demand variation and by an incentive from utilities (such as for natural gas) and the federal tax credit.
- Recovering and using waste heat improves the financial and environmental performance of CHP projects. The impact is more significant on facilities with highly correlated electricity and thermal demand, which can help to maximize the use of recovered heat and the value of the project.
- To capture the full value of DG, the next step would require distribution-level data related to deferred investment in transmission and distribution systems.

Figure 37. Fuel Cell With Heat Recovery Annual Value in Different Facilities²⁹¹



²⁹⁰ Jafari, M., and Hahani, K. (2017, June). *CHP evaluation: Data and technology driven methodology*. Rutgers Center for Advanced Infrastructure and Transportation, Laboratory for Energy Smart System (RU LESS). Retrieved from: http://www.njcleanenergy.com/files/file/Library/CHP_Evaluation_FinalReport_18July2017.pdf

²⁹¹ Jafari and Hahani, 2017, figure 3, 6.

d. Connecticut Fuel Cell Program

Connecticut has continually supported fuel cell applications by providing policy support and incentives. Fuel cells operating on renewable and nonrenewable fuels are classified as a Class I renewable resource in Connecticut. In 2017, Connecticut enacted Public Act No. 17-144, which allows distribution companies to acquire new fuel cell electricity generation for providing distribution system benefits, including, but not limited to, avoiding or deferring distribution capacity upgrades, enhancing distribution system reliability and voltage or frequency improvements. This Connecticut legislation, as well as other federal and state incentives for renewables and efficiency, has laid a regulatory foundation for fuel cell applications that is stronger than many other states. The fuel cell supply chain and manufacturing capacity in Connecticut have grown significantly.

As a result of this strong regulatory foundation, Connecticut companies have installed and are planning more than 64 MW of large stationary fuel cells. Based on a subset of targets in the 2018 *Hydrogen and Fuel Cell Development Plan*, the Connecticut potential to develop stationary fuel cell generation capacity is 170 MW, which would provide the following annually:

- Production of approximately 1.44 billion kWh of electricity;
- Production of approximately 3.09 million MMBTUs of thermal energy; and
- Reduction of NOx emissions by up to approximately 160 metric tons (electric generation only).

e. Stationary distributed fuel cell market participation feasibility

Fuel cell capital and O&M costs have dropped sharply in recent years, but cost is still considered a major challenge.^{292, 293} The financial results of leading fuel cell firms, including Bloom Energy, Doosan and FuelCell Energy, over the last few years are not promising. The fuel cell industry is seeing low profits and is far from reaching its scaling-up point.²⁹⁴ Among the five main types of fuel cells, lower temperature systems are considered suitable for smaller applications.²⁹⁵

The feasibility of fuel cell systems turns in part on how they are connected to the grid. Like other DERs, there are three ways to look at how distributed power generation operates: as a part of a nanogrid or microgrid or as a virtual power plant.

²⁹² NCFRC (2018, May). *Stationary fuel cell cost trends*. Assessment produced by National Fuel Cell Research Center. Retrieved from:

http://www.apec.uci.edu/Research/whitePapers/PDF/Stationary_Fuel_Cell_Cost_Trends_051918.pdf

²⁹³ Spiegel, J. E. (2016, November). *Fuel cells: Promising but struggling to catch on*. Yale Climate Connections. Retrieved from:

<https://www.yaleclimateconnections.org/2016/11/fuel-cells-pros-and-cons/>. See also an Unsubsidized Levelized Cost of Energy comparison in

Lazard (2017, November). *Lazard's levelized cost of energy analysis – Version 11*. Retrieved from:

<https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf>

²⁹⁴ Wesoff, E. (2018, December 26). Fuel cell industry financials in 2018. GTM Research. Retrieved from:

https://www.greentechmedia.com/articles/read/stationary-fuel-cell-industry-financials-2018-in-brief?utm_medium=email&utm_source=GridEdge&utm_campaign=GTMGridEdge#gs.UhEfKfRfD

²⁹⁵ Costs of stationary fuel cell systems vary by type and application. For detailed comparison of different fuel cell types

and their performance parameters, see U.S. EPA (2015e). *Catalog of CHP technologies: Section 6 technology*

characterization—fuel cells. Retrieved from: [https://www.epa.gov/sites/production/files/2015-](https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_6_technology_characterization_-_fuel_cells.pdf)

[07/documents/catalog_of_chp_technologies_section_6_technology_characterization_-_fuel_cells.pdf](https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_6_technology_characterization_-_fuel_cells.pdf)

Navigant defined a virtual power plant as “a system that relies upon software and a smart grid to remotely and automatically dispatch and optimize DER via an aggregation and optimization platform linking retail to wholesale markets.”²⁹⁶ Distributed fuel cell systems can be aggregated using advanced communication and intelligent control technologies, which make tens to hundreds of fuel cells act as dispatchable resources, while meeting a primary purpose as backup for the host.

In ISO-NE, distributed fuel cells can bid into the wholesale markets through demand response programs. In order to participate in a forward capacity auction (FCA), qualified capacity of a demand resource must be at least 100 kW in size. Installed demand response measures should result in additional reductions over time to the installed capacity requirements.²⁹⁷ Fuel cells can be an important contributor for local peak demand response or peak shaving. When aggregated, DER portfolios can compete to deliver better service to the grid.²⁹⁸

For fuel cells to be dispatched in energy markets, the market prices have to be high enough for covering the cost of hydrogen and delivery, which is significant in the total cost of generation for systems operating on direct hydrogen. NREL estimated that the energy market prices need to be above \$0.4/kWh to offset the cost of hydrogen fuel, storage and delivery.^{299, 300} By looking at historic energy prices in different ISO/RTOs, NREL concluded that there are limited high price hours in day-ahead and real-time energy markets, which can potentially offer such opportunities. But fuel cells can provide a valuable high-priced resource for those high-demand hours.

Fuel cells can also participate in ancillary service markets. Technically, fuel cells can respond fast enough and for sufficient duration. However, taking into account lifetime fuel cell cost impacts, the most viable markets for fuel cell backup units are as spinning and non-spinning reserves during system emergencies.³⁰¹ With more renewable integration, fuel cells will be increasingly valuable. Adding a hydrogen energy storage system or fuel cell/battery hybrid system further allows fuel cells to manage power by smoothing outputs, reducing thermal loads, voltage variation, frequency variation and fault currents.

²⁹⁶ Asmus, P., and Lawrence, M. (2016). *Making sense of new public power DER business models: The business case for energy storage*. Navigant Research. Prepared for Sunverge Energy, Inc. Retrieved from: https://sun-connect-news.org/fileadmin/DATEIEN/Dateien/New/Sunverge_NavigantWhitePaper4-20-2016FINAL-1.pdf

²⁹⁷ Engelson, J. (2019, February 27). FCM show of interest for new demand resources: For the fourteenth forward capacity auction (CCP 2023–2024). ISO New England. Retrieved from: <https://www.iso-ne.com/static-assets/documents/2019/02/20190227-fcm-soi-new-dr.pdf>

²⁹⁸ GridLAB (2018, August). *The role of distributed energy resources in today's grid transition*. Portland, OR: GridWorks. Retrieved from: https://static1.squarespace.com/static/598e2b896b8f5bf3ae8669ed/t/5b91b70970a6adc1daa82bb9/1536276258564/GridLab_RoleOfDER_online.pdf

²⁹⁹ The study assumes that the fixed O&M costs of PEMFC systems will be reduced to \$25 per delivery, and hydrogen cost will be reduced to \$4/kg.

³⁰⁰ Ma, Z., Eichman, J., and Kurtz, J. (2017, March). *Fuel cell backup power unit configuration and electricity market participation: A feasibility study*. National Renewable Energy Laboratory. Retrieved from: <https://www.nrel.gov/docs/fy17osti/67408.pdf>

³⁰¹ Ma et al., 2017, 17–18.

3. Additional factors for qualitative valuation

Fuel cells installed at customer sites can provide a full range of system values like other distributed resources, though the specific value of any given system may depend on its technology, operating characteristics and location. The methodologies used to quantify avoided generation, transmission and distribution costs for other types of DG should also be applied to fuel cells. Some specific characteristics may contribute to higher fuel cell values compared to other distributed generation technologies.³⁰²

- Electricity generation through electrochemical reaction rather than combustion
 - Higher electrical efficiency
 - Greater reliability, partially due to fewer moving parts
 - Improved power quality
 - Avoided emissions and related health benefits
- Low acoustic
- Virtually zero emissions
- Low vibration
- Easy zoning/small land footprint.

Features that are shared with some but not all distributed generation include:

- Cogeneration mode potential, with higher overall system efficiency
- 24/7 baseload operations
- Fuel flexibility
- Suitable for renewable fuels.

A major focus of fuel cell value lies in the last two categories of layer stack values: customer value and societal/public value.

a. Customer value

Fuel cells can be cost effective if combined with CHP. Reliability and resilience benefits are well recognized by customers. New York, southern New England and the Mid-Atlantic states have been significantly impacted by extreme weather events, which increases the value of reliable backup fuel cells when the grid power is out of service. Fuel cell systems have already provided electricity, heat and hot water to critical facilities during several system outages in the Northeast region.³⁰³ As shown in the case studies, fuel cells are accepted as resilience power to replace diesel backup

³⁰² NCFRC (2011, July). *Build-up of distributed fuel cell value in California: 2011 update background and methodology*, p. 6–7. Irvine, CA: National Fuel Cell Research Center.

³⁰³ Connecticut Hydrogen Fuel Cell Coalition, 2018, 5.

generators for telecommunications, schools, hospitals and other important facilities in the United States.³⁰⁴

Community microgrids with fuel cells and islanding can benefit from both daily and system emergency operations as they can effectively integrate intermittent wind and solar energy in microgrids. Customers can also increase the control over their energy consumption by actively changing fuel cells' output.

b. Societal value

i. Emissions reduction

DOE-funded analyses show that fuel cell CHP systems have a potential to achieve carbon emissions reductions of 35% to more than 50% over conventional heat and power sources, with much greater reductions — more than 80% — if biogas is used in the fuel cell. As for criteria pollutants, fuel cells emit about 75% to 90% less NO_x and about 75% to 80% less particulate matter than other CHP technologies on a life-cycle basis.³⁰⁵

Compared to solar and wind, fuel cell CHP can generate more carbon emission reductions under operational scenarios, which utilize its high-load factor. Operating at a load factor of 95%, fuel cell CHP can save four times as much carbon emissions as the same size solar PV with a 15% capacity factor under certain operational and grid scenarios.³⁰⁶

ii. Water and land saving

There is no consumption of water during the normal operation of fuel cell systems. Fuel cells are high-energy density resources, which can be designed for indoor or outdoor installation, so the environmental footprint impacts can be very small.

iii. Job and local economic impacts³⁰⁷

Fuel cell plants can provide local tax, capital investment and job creation. It is estimated that the manufacture and installation of 50 MW of fuel cell plants can contribute to:

- In-state capital investment of approximately \$200 million;
- Approximately \$45 million in local property tax revenue over 10 years;
- Approximately \$5 million of investment in local electrical and gas infrastructure; and
- Approximately 400 direct manufacturing jobs and an additional 800 indirect jobs.

³⁰⁴ Galbraith, S. (2015, October 28). Resilience power case study series: fuel cell for resilience power [blog post].

Montpelier, VT: Clean Energy Group. Retrieved from:

<https://www.cleaneenergygroup.org/fuel-cell-case-studies-highlight-clean-resilient-power-technology/>

³⁰⁵ U.S. DOE (2015). *Chapter 4: Advancing clean electric power technologies; Stationary fuel cells technology assessment*. Retrieved from:

<https://www.energy.gov/sites/prod/files/2015/12/f27/QTR2015-4Q-Stationary-Fuel-Cells.pdf>

³⁰⁶ Doosan (2014, October). *The green edge of fuel cell*. Seoul, South Korea: Doosan Group. Retrieved from:

http://www.doosanfuelcell.com/download/pdf/catalog/the-green-edge-of-fuel-cells_en.pdf

³⁰⁷ Rinebold, J. M., and Aresta, P. (2018, May 1). *Fuel cell distributed generation: Cost, value, and market potential*. Connecticut Center

for Advanced Technology. Retrieved from: <http://neesc.org/wp-content/uploads/2018/05/Fuel-Cell-DG-Cost-and-Market-Acceptance-CCAT-5-2-18.pdf>

iv. Energy security

The higher efficiency of fuel cells means less fuel use and greater affordability. Different applications of fuel cell technology (stationary, portable, mobile) and platforms can link energy, transport and building sectors and provide opportunities to increase fuel use efficiency.

Appendix F: Value Stack for DERs Overview

- A. Values Akin to Generation
 - 1. Production energy value
 - 2. Production capacity value
 - 3. Production environmental compliance value/avoided costs (current and future regs)
 - 4. Reduced reserves
 - 5. Risk
 - 6. Reduced RE obligation or RPS costs
 - 7. Demand-response induced price effect
 - 8. Reduced O&M
- B. Values Akin to Distribution Plant
 - 1. Reduced peak — overall peak reductions and ability to manage circuit peak reductions
 - 2. Distribution capacity costs
 - 3. Line losses
 - 4. Reduced credit and collection costs and avoidance of uncollectible bills for utilities
 - 5. Reduced O&M
 - 6. Enhanced distribution reliability
- C. Values Akin to Bulk Transmission
 - 1. Transmission capacity costs
 - 2. Line losses
 - 3. Reduced O&M
 - 4. Enhanced bulk system reliability
- D. Customer Values
 - 1. Customer choice and control
 - 2. Reduced energy usage from electricity
 - 3. Reduced energy usage from other fuels (fuel oil, gas, propane, wood)
 - 4. Reduced bills
 - 5. Reduced overall energy usage
 - 6. Resilience benefits
 - 7. Property values
 - 8. Customer comfort
 - 9. Talk about any specific LMI values from research and studies
- E. Societal Values, Public Values, Customer Values
 - 1. Health impacts
 - 2. Employee productivity
 - 3. Benefits for low-income customers
 - 4. Air quality improvements
 - 5. Water quality improvements
 - 6. Employment and local economic impacts
 - 7. Energy security



RAP[®]

Energy Solutions for a Changing World

Regulatory Assistance Project (RAP)[®]

Belgium · China · Germany · India · United States

50 State Street, Suite 3

Montpelier, Vermont 05602
USA

1 802-223-8199

info@raponline.org
raponline.org