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A Review of Distributed Energy Resources (DRAFT)

New York Independent System Operator

Prepared by DNV GL

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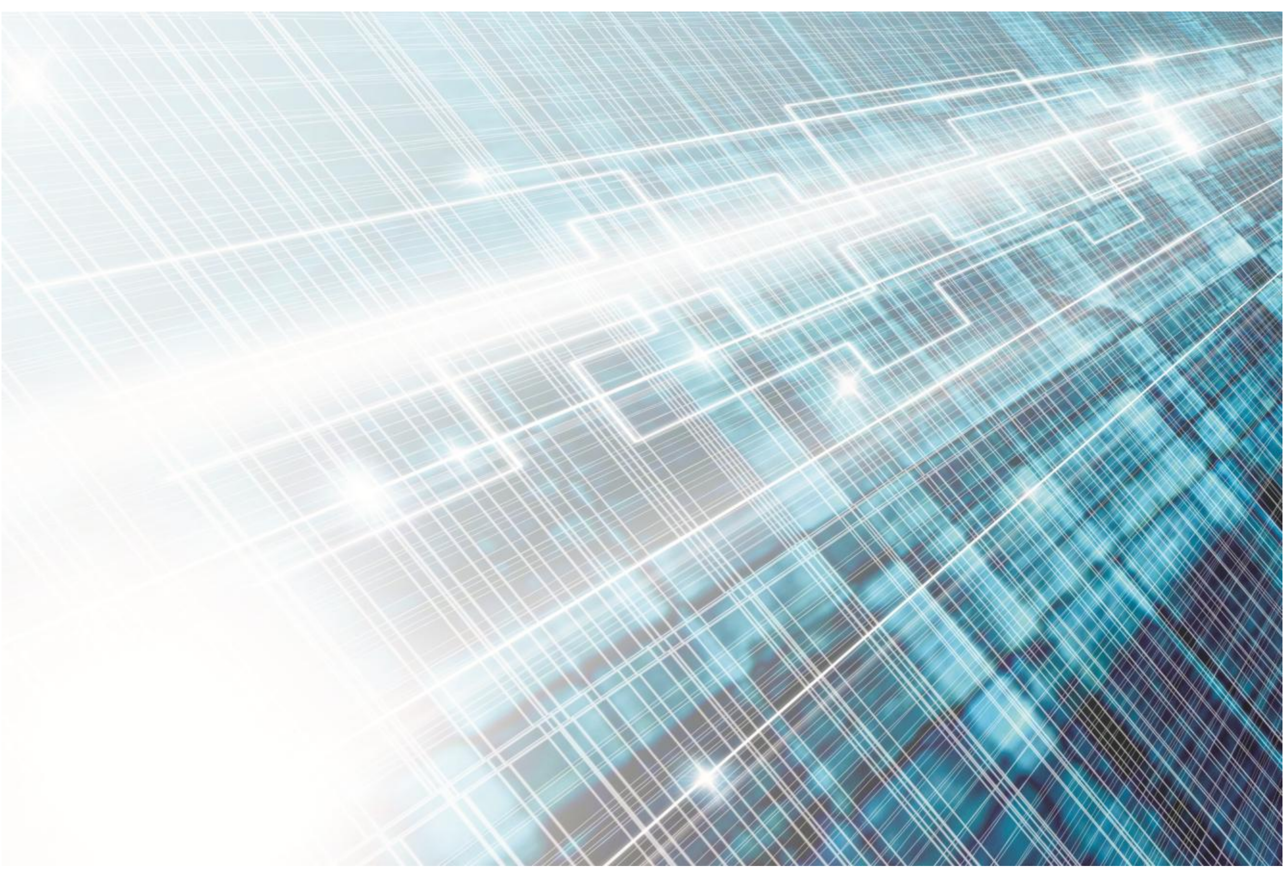

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1 EXECUTIVE SUMMARY

Increasing amounts of distributed energy resources (DERs) located on the customer side of the electric grid represent both a challenge and an opportunity for grid operators. As the grid evolved around centralized generation, grid operators in conjunction with policymakers need to consider adjustments to the current framework for power supply dispatch and delivery to realize the potential benefits of increased DER penetration. The first step is to assess the implications of DERs. Policy and grid operator rules will have a strong influence over DER adoption and on its successful integration with the grid. Such rules need to account for the constraints of the grid, while others can adapt to a more decentralized framework. Current approaches to integrating demand response and energy storage represent a starting point for integration of DERs, though additional adjustments are likely necessary. Discussion among industry stakeholders is critical to understanding the implications of changing our generation resource portfolio and transforming our approach to power delivery. This is the first step towards ensuring a smooth transition to the future grid. The NYISO commissioned this study to collect information that can aid the discussion. It highlights and summarizes issues relevant to DER, drawing from information about DERs and lessons learned to date in New York and other jurisdictions.

Defining Distributed Energy Resources

For this study, DER technologies are defined as "behind-the-meter" power generation and storage resources typically located on an end-use customer's premises and operated for the purpose of supplying all or a portion of the customer's electric load. Such resources may also be capable of injecting power into the transmission and/or distribution system, or into a non-utility local network in parallel with the utility grid. These DERs include such technologies as solar photovoltaic (PV), combined heat and power (CHP) or cogeneration systems, microgrids, wind turbines, micro turbines, back-up generators and energy storage. Some, including the New York Public Service Commission (PSC), have defined DERs more broadly to include energy efficiency and demand response.[1] While these are important resources that can contribute to grid reliability, this study is focused more narrowly on distributed resources capable of producing power to support the host load or the grid, as these technologies have been evolving at a rapid pace in recent years and present the NYISO with unique planning, operational and market administration challenges.

In addition, the term "behind-the-meter" is meant to represent resources that are generally not connected on the bulk or wholesale electric power system, but are connected behind a customer's retail access point (the meter). These resources may be operating to serve the customer's internal electric loads or may be operating for the purpose of selling into the bulk electric power system. There are resources that are not behind an end-use customer's primary meter (for example, remote-net-meter) or in other configurations that are not physically "behind-the-meter" (such as "offset" tariffs) but that would fall under the intent of this study, and are not meant to be excluded other than for the purpose of brevity.

Summary of Findings

Is DER Adoption a True Phenomenon and will DER Adoption Continue?

Adoption is Relatively Strong and Growing

DER adoption is well underway in the United States, due in part to state, local, and federal policy encouraging adoption and also to performance improvements and cost reductions in the technology. While

[1] "Reforming the Energy Vision" NYS Department of Public Service Staff Report, Case 14-M-0101, April 24, 2014.

all DERs have seen growth in installed capacity, photovoltaic solar (PV) has seen the largest adoption in recent years. PV constitutes 80 to 90% of the total installed capacity among DER installations two megawatts or less – and among states - California, New Jersey and Arizona lead the nation.

New York ranks relatively highly with regard to DER adoption – it is within the top five states for total cumulative installed capacity of DERs under two megawatts. New York also ranks within the top ten states for cumulative installed capacity of PV, energy storage and CHP under two megawatts.

Technology Investments and Cost and Performance Improvements Continue

DERs constitute a variety of technologies, some with more maturity and penetration than others, and some in more rapid stages of development than others. CHP has seen enhancements in recent years, but costs have generally not come down as rapidly as other technologies like PV and energy storage. PV has seen rapid development over the past two decades in terms of cost and performance, as has energy storage. According to the Solar Energy Industries Association, national average installed residential and commercial PV system prices dropped by 31% from 2010 to 2014, with a reduction in New York of 4% within the last year.[2] Recent advancements in energy storage have also been strong. For example, modern lithium-ion batteries are estimated to have doubled the energy density than early versions and are ten times cheaper.[3]

Expectations are that trends in cost reduction will continue. Many in the industry believe there is opportunity to reduce non-module PV costs. In 2013, NREL released a roadmap to reduce non-hardware ("soft") costs by 2020, with targets of $0.65/W and $0.44/W for residential and commercial systems, respectively.[4] Furthermore, private and public investment in additional research and development in PV and energy storage are strong and targets for cost reductions are bold. The U.S. Department of Energy currently has active initiatives to reduce PV installed cost, including the SunShot Initiative which has the goal of reducing residential and commercial installed costs of PV systems to $1.50/W and $1.25/W, respectively, by 2020.[5] The Joint Center for Energy Storage Research, a public-private research partnership managed by the Department of Energy, has set a cost reduction goal of $100/kWh for stationary storage a with a life of 20 years and 7,000 cycles and round trip efficiency of 95%.

Microgrids are one of the newest technologies being implemented in the electricity grid today. While microgrids have existed on naval and sea-going vessels for nearly a century, their implementation in the electricity grid are a relatively recent phenomenon. Today, however, applications are increasingly developing across the country. According to GTM research, there are 81 microgrids operational today and 35 more are planned.[6] Additional information about microgrids in New York is expected to be available soon. The PSC, NYSERDA and the Department of Homeland Security and Emergency Services are currently conducting a feasibility study of microgrids in New York to assist with disaster response.[7] The New York State Smart Grid Consortium is also compiling a database of microgrid projects in New York State.[8]

Fuel cell markets are currently growing in stationary applications globally, though domestic growth rates are much slower. Shipments of stationary fuel cells grew from about 2,000 shipments in 2008 to about 25,000

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[2] SEIA, State Solar Policy, New York Solar. Viewed May 2014. Available online at: http://www.seia.org/state-solar-policy/new-york

[3] Source: Van Norden, 2014. Available online at: http://www.nature.com/news/the-rechargeable-revolution-a-better-battery-1.14815#batt2

[4] For more information, see: http://www.nrel.gov/news/press/2013/3301.html

[5] For more information, see http://energy.gov/eere/sunshot/sunshot-initiative

[6] GMT Research, 2014.

[7] See A.7049/Crespo; Chapter 221 of 2013

[8] See http://nyssmartgrid.com/wp-content/uploads/NYSSGC-RFP-Microgrid-Project-Inventory-1-6-14.pdf for more information.

shipments in 2012.[9] However, most of the market growth is abroad rather than domestic. Nevertheless, investment in fuel cells in the United States has been relatively strong and research continues. U.S. investors made the largest cumulative investment globally in fuel cells between 2000 and 2011, at $815 million.[10] Though federal research budgets for fuel cells have declined somewhat in recent years, funding continues. Department of Energy goals for stationary fuel cells by 2015 include a $750/kW cost target with 40% efficiency and 40,000 hour durability.[11]

There is Sizeable Remaining Technical Potential for DERs in the U.S. and in New York

The remaining technical potential for DERs in the United States is high and though New York is relatively advanced in terms of total installed capacity of DER, there appears to be additional room to grow. New York ranks relatively highly in rooftop PV potential according to a 2012 NREL study. Furthermore, a recent report by NYSERDA estimates a sizeable technical and economic opportunity for PV. For residential PV, NYSERDA estimates a total technical potential of 881 MW cumulative peak capacity and 2,836 GWh production by 2020 and 2,615 MW cumulative peak capacity and 8,223 GWh production by 2030. For PV serving commercial customers, NYSERDA estimates a total technical potential of 1,174 MW of cumulative peak capacity and 3,706 GWh of production by 2020 and 3,487 MW of cumulative peak capacity and 10,745 GWh of production by 2030.[12]

Customers May Benefit from DER Adoption, Though Challenges Remain

Though it is feasible for utilities to adopt DERs for their own benefit, customer benefits from DER could also drive penetration on the customer side of the meter. Benefit streams commonly attributed to DERs include:

- energy and demand bill management (avoided costs);
- power outage mitigation or critical power support during power outages (resiliency);
- power quality improvement (enhanced reliability);
- direct compensation by grid operators or providers for services (revenue); and
- financial incentives as defined by local, state or federal policymakers (avoided costs or revenue).

The performance of a DER can also depend significantly on:

- the physical location of a customer and asset;
- a customer's end use profiles; and
- the presence of other behind-the-meter technologies or capabilities such as demand response or generation assets.

Challenges for DER adoption include:

- Complexity of policies, requirements and tariffs across jurisdictions, including
    - Interconnection standards;

[9] http://energy.gov/sites/prod/files/2014/03/f11/2012_market_report.pdf
[10] http://www.hydrogennet.dk/fileadmin/user_upload/PDF-filer/Brint_og_braendselsceller_internationalt/Dansk-amerikansk_samarbejde/Fuel_Cell_Collaboration_in_the_United_States_-_Follow_Up_Report_DRAFT-2.pdf
[11] DOE 2013
[12] NYSERDA 2014

- Siting and permitting requirements; and
- Utility tariff agreements and eligibility.

- Determining fair compensation for the benefits of DERs to the grid, including which parties should receive financial compensation and how much. The benefits of DER can accrue to different stakeholders complicating the ability to identify compensation for these resources for their actions and thereby justify customer investments through potential revenue streams.
- Engineering can be costly and complex if no turn-key solution is available.
- Financing can be difficult to obtain, particularly where technologies are still gaining experience in the market or where no turn-key solutions are available.
- Customers must weigh the payback of investment in DERs versus the payback from investment in core business.
- Environmental and safety requirements can limit the installation or operations of some DER assets depending on their emissions profile or chemical make-up.

What Influence do Federal, State and Local Policy and Grid Operator Rules have on DER Adoption and Integration?

Incentives Can Help Align Customer and Grid Operator Goals

The nature of DER benefits depends greatly on the mix of DERs on the grid and on the ability to coordinate DER activities in a way that aligns individual customer interests with grid interests. Grid owners and operators may have reason to incentivize certain types of DER adoption and behavior on their system. For example, by offering incentives, transmission and distribution owners and operators could potentially motivate investment in particular locations or shift in operations to align customer benefits with grid benefits. This could potentially result in the ability defer distribution, transmission or generation capacity investments. Alternatively, incentives can motivate a shift in operations or location or investment in certain types of DERs or integration equipment. Operational savings might include power system loss reductions or avoided energy purchases. The benefit of avoided energy depends on alternative costs for supply, which can vary by time of day.

Customers Encounter a Number of Economic Signals from their Load Serving Entity, Wholesale Operator, and Local, State and Federal Government

Retail rates, including energy, demand and standby charges can influence DER operations and investment by providing incentives to reduce peaks and establishing a basis for comparison of per unit production. Rate structures can vary, including fixed, variable or a combination of the two, which will also likely influence DER operations from an economic perspective. A variety of retail rate offerings are available in New York, ranging from fixed charges to time-of-use charges to mandatory hourly pricing.

Net metering rules define the eligibility requirements, size, capacity, and prices for DER that can be offset or sold back to the grid at retail rates. The number of customers in the United States with net metering has steadily grown over the years. According to data collected by the EIA since 2003, the number of customers with net metering has grown by a factor of over 48 between 2003 and 2012.[13] The majority of net metering applies to PV units. Based on 2012 data from EIA, New York ranks within the top ten states for estimated total capacity on net metering.[14]

Some utilities in the United States have implemented alternative approaches to net metering for compensation of excess production. For example, Austin Energy has implemented a Value of Solar Tariff. Rather than applying net metering, Austin Energy bills customers at the full retail rate for their load and separately credits them the determined 'value of solar' for each kWh they generate.

Feed-in tariffs (FITs) are used in portions of the United States, including New York. These tariffs typically guarantee customers who own eligible generation a set price from their utility for all of the electricity they generate and provide to the grid. Currently, the Long Island Power Authority runs a CLEAN Solar Initiative FIT. Its latest iteration had a cumulative program target of 100 MW.[15]

The interconnection process, and related technical, contractual, metering, and rate rules, is the process by which a generator connects to the grid. The authorities overseeing this process and the manner in which they treat resources depends on:

- **Point of interconnection.** Whether the assets are connecting directly into the transmission grid versus distribution grid or behind the customer meter.
- **Asset size.** What the planned capacity is that will be interconnected.
- **DER application.** Whether the unit produces excess power, and whether and how it plans to interact with the wholesale market.

Generally, procedures for interconnection vary depending on whether resources are on the utility side of the meter or behind the meter. The Standard Interconnection Requirements procedures in the State of New York were recently updated (February 2014) by the PSC for a more transparent and swift process for distributed generation below 2 MW. A "fast track" application process is available to distributed generation below 50 kW, or to inverter-based generators (such as PV) below 300 kW, with some exceptions such as underground interconnections.

In addition, a Number of Federal, State and Local Incentives Exist which Influence DER Economics

Federal incentive programs are generally geared towards supporting state or local governments in reaching their energy, efficiency and development goals by providing grants and loan guarantees to eligible projects. A portion of these incentives are aimed at rural communities and combine goals for economic development and environmental protection. There are also incentives structured as corporate and personal tax incentives. While many incentives may apply to DER indirectly, the federal business energy investment tax credit, the Rural Energy for America Program and residential renewable energy tax credit are examples of programs more directly tied to DER installations.

At the state and local levels, there are multiple incentive types and programs available. In states with Renewable Portfolio Standards (RPS), many utilities are required to procure renewable energy to meet

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[13] U.S. DOE, EIA, *Electric Power Annual 2012,* Table 4.10. Net Metering Customers and Capacity by Technology Type, by End Use Sector, 2013.

[14] DOE, EIA Form 861 surveys utilities, asking for information on systems 2 MW or smaller. For more information, see: http://www.eia.gov/survey/form/eia_861/instructions.pdf; DOE, EIA Form 861, 2012 survey results. For more information, see http://www.eia.gov/electricity/data/eia861/.

[15] PSEG Long Island, Clean Solar Initiative Feed-In Tariff II FAQ. For more information, see: https://www.psegliny.com/page.cfm/FIT/FIT-IIFAQ

certain targets. In some cases, there are special carve-outs for distributed generation. In total, 29 states have RPSs and 16 of these states have carve-outs for solar or another form of distributed generation. The PSC adopted a RPS for New York in September 2004. In its current implementation, the RPS sets a target of 30% of state electricity consumption from renewables by 2015.

Several other state and local incentives may be relevant to DERs. For example, the Property Assessed Clean Energy financing initiatives provide an innovative way to finance renewable energy upgrades to buildings via property tax assessments. In addition, many states offer tax incentives geared towards renewables (typically PV) and energy efficiency (including CHP), such as sales tax exemptions and corporate tax credits.

This year, the PSC has launched an initiative, Reforming the Energy Vision (REV), to encourage deeper penetration of DERs, engage end-users, promote efficiency and wider use of distributed resources as well as meet the challenges of aging infrastructure and severe weather events.[16] The PSC Chair, Audrey Zibelman, has outlined a goal to decentralize the grid and engage consumers, allowing DERs to play an active role in grid management.[17] Proceedings are currently underway.

In addition, in January 2014, the State published a draft State Energy Plan, describing several new and on-going initiatives, policies, and programs to meet State and local energy goals.[18] Several initiatives are pertinent to DERs.

In support of state policy objectives, NYSERDA administers several incentive programs targeting renewables, energy efficiency and sustainability. Sample programs related to DERs include:

- Solar PV Program Financial Incentives;
- Solar Thermal Incentive Program;
- CHP Performance Program; and
- CHP Acceleration Program.

In addition to state-wide initiatives, several cities within New York have energy plans in place or under development. For example, in 2011, the City of New York published a city energy plan with the explicit goal to "build a greener, greater New York by reducing energy consumption and making our energy supply cleaner, more affordable, and more reliable."[19] Many of the goals outlined in the plan can be addressed with DER.

What Effect will DER Adoption have?

The net effect of DERs on the grid will depend on the DER type, its capability and the application for which the asset is being used. Ultimately, distribution, production and wholesale market implications need to be assessed further so that any issues can be resolved prior to large-scale adoption of DER.

The Emissions Impacts of DERs Depends on DER Type and Will Likely Evolve Over the Next Several Years as Policies Regulating Central and Distributed Generation Evolve

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[16] http://www3.dps.ny.gov/W/PSCWeb.nsf/ArticlesByTitle/26BE8A93967E604785257CC40066B91A?OpenDocument
[17] http://www.restructuringtoday.com/public/13625.cfm
[18] See http://energyplan.ny.gov/Plans/2014.aspx for more details.
[19] For additional detail, see http://nytelecom.vo.llnwd.net/o15/agencies/planyc2030/pdf/planyc_2011_energy.pdf

DERs have the potential environmental benefit of increased efficiency, due in part to avoided transmission and distribution losses. In addition, some DERs, such as CHP or fuel cells, can increase overall energy efficiency by cogenerating power while meeting heating and cooling needs, while others, such as PV or energy storage, produce no emissions.[20] However, the net air quality effects are highly dependent on the central generation mix of the region, the time of day, the location of the central power plant as well as the distributed technology and usage, emissions limits, and control measures enforced. Furthermore, the exposure to pollutants is not strictly related to total pollutant emissions but rather is affected by the spatial and temporal distribution of emissions and resulting atmospheric chemistry and transport.[21] Of particular concern is high ground-level concentrations of pollutants near population centers.[22]

New York City and surrounding metropolitan areas are designated as a moderate non-attainment area for ozone. In addition, counties in and around New York City are designated non-attainment areas for particulate matter ($PM_{2.5}$).[23] This means air quality regulation in these areas is more stringent than in the rest of the state, especially for NO_x and PM. Hydrocarbon fuelled DER sources can add to ozone pollution issues as they are typically located in urban areas and generally have shorter stacks than central station power plants, causing emissions to impact the vicinity of the source. In response to the expanding DER market, DEC is implementing a new rule to set emissions standards for distributed generation, "6 NYCRR Part 222."[24] The rule is expected to be finalized in 2014.

Over the past ten years, emissions from central generation in New York State have been steadily declining. This is due, in part, to older generation being retired and replaced by newer, more efficient generation facilities that are also subject to more stringent environmental regulations.

Central generation, especially with current and future technology and regulations, can be more efficient and will generally emit fewer pollutants per megawatt-hour produced, while distributed generation can help avoid transmission losses and can address local thermal needs, thus reducing overall fuel consumption and affecting emissions dispersion. Policies regulating the emission profiles of centralized generation and DERs will have a significant impact on the net effect of DERs displacing centralized generation.

DERs Can Potentially Increase Variability in Load and Create Forecast Error

DERs can significantly alter 'traditional' load shapes, either increasing or reducing peaks, and potentially adding more variability in the load shape across hours, though the effect of DERs on load shapes vary significantly across DER technology. For example, cloud cover can significantly impact the net production profiles of a customer with PV where no resource exists to smooth out the profile. Without a clear means to predict how DER net load profiles might vary over time, it is feasible that DERs can lead to more variability and load forecast error. In some cases, variability among resources can be correlated, depending on the application. For example, where storage is applied to PV applications, its charging and discharging profiles would be impacted by variability in the PV profile. In addition, the net resulting variability of a profile can be influenced by multiple drivers at once – an example being where multiple applications of DERs or multiple

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[20] Emissions may be associated with energy storage, depending on the charging/discharging efficiency and the source used to charge.

[21] Carreras et. al, University of California, 2010 "Central power generation versus distributed generation - An air quality assessment in the South Coast Air Basin of California"

[22] Ibid.

[23] Nitrogen oxides (NO_x) and volatile organic compounds (VOCs) react when it is hot and sunny and produce ozone. Ground-level ozone is especially prevalent in cities, due to the concentration of NO_x and VOCs and the favorable weather patterns during summer, and at high concentration is considered a health hazard.

[24] 6 NYCRR Part 222 went into effect in 2008, but is still under development http://www.dec.ny.gov/chemical/37107.html

DER types are used at a given site. The challenge of potentially increased variability from DERs may be exacerbated by the increased variability of centralized supply, such as non-dispatchable wind or solar, and of increased variability of loads. In addition, without information about DER behavior, forecast errors can increase. CAISO reported that their load forecasts were being affected by distributed generation, including distributed solar.[25] Germany also experienced greater day ahead forecast errors, due largely to distributed PV.

Integration of DERs Should Consider Effects on Market and System Dynamics

DERs can potentially offer increased flexibility and resilience by expanding the resources available to grid operators. However, increased incorporation of these assets into wholesale electric markets requires careful consideration as their loads can potentially create inadvertent system dynamics if not properly accounted for by system operators. Research by DNV GL and NYISO found that demand responding to price, with no feedback or price elasticity information available to market operators, can result in imbalances between supply and demand which in turn can lead to fluctuations in price, supply, and demand.[26]

Planning around DER Integration Should Consider the Portfolio of Other Resources Available in the Markets

DERs have the potential to offset investments in generation, transmission, and distribution. However, the coordination of DERs with loads will determine which local or system upgrades or additions can be deferred. In addition, the generation portfolio mix will determine the net effect of the aggregate net load reductions. In California, the portfolio mix is projected to consist of a sizeable percentage of renewable energy, including wind and solar, of which a significant portion is distributed solar. As a result, the CAISO expects to need significant amounts of intrahour load following resources and continuous ramp-up capability. German grid operators also faced challenges with DER integration, including issues of over-generation. With insufficiently price sensitive supply and load, wholesale prices have gone negative on some off-peak days during hours coincident with peak solar output in Germany.

As a result, revenues that traditional generators relied upon may no longer be sufficient to maintain operations. Reports from Germany indicate earnings for traditional power plants are dropping significantly.[27] Where PV production offsets retail rates, customers look to the retail prices, rather than wholesale prices when deciding on adoption. In effect, distributed PV production is being adopted on a different basis from the wholesale generation resources it is competing against in the market, even where the resources are not actively enrolled in the market. Under current retail rate structures, PV production will 'beat out' other resources in the wholesale market. Recently, in the United States, Barclays has downgraded the electric sector of the U.S. high-grade corporate bond market based on its forecast of long-term challenges to utilities based on solar energy.[28]

While the reduction in wholesale prices is beneficial for wholesale power consumers, there remains the concern over whether the remaining portfolio mix can satisfy the requirements for ancillary services needed to operate the grid reliably. Many of the higher-cost assets also tend to be those with greater ramping capability. For example, the average ramp rate of a U.S. combined cycle gas turbine is 15 to 25 megawatts-

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[25] GE Energy, 2012. Available online at: http://pjm.com/~/media/committees-groups/task-forces/irtf/postings/pris-task3b-best-practices-from-other-markets-final-report.ashx

[26] NYISO and DNV GL 2011. Available online at: http://www.dnvkema.com/Images/Markets%203%200%20IEEE%20Paper%2011-7-2011.pdf

[27] *How to lose half a trillion euros: Europe's electricity providers face an existential threat*. The Economist, Oct 12th 2013. Available online at: http://www.economist.com/news/briefing/21587782-europes-electricity-providers-face-existential-threat-how-lose-half-trillion-euros

[28] For more information, see: http://blogs.barrons.com/incomeinvesting/2014/05/23/barclays-downgrades-electric-utility-bonds-sees-viable-solar-competition/

per-minute while a typical coal plant's ramp rate is 3 megawatts-per-minute.[29] Additional studies are needed to estimate upcoming ancillary needs under the changing mix of resources and loads, and to estimate the capability of market resources (either demand or supply) in meeting those needs.

Additional Consideration Should be Given to the Integration of DER in Long-Term Planning

In many markets, demand response resources are successfully being used to support resource adequacy. DERs have the potential to do this as demand response resources, power production resources or both. However, some issuesin this area include:

- Clear and comparable consideration by transmission providers regarding non-transmission alternatives (NTAs), including demand response, distributed generation, storage and microgrid deployment, in transmission planning;[30]
- The development of approaches for defining the capacity value of DERs, particularly distributed variable resources; and
- Greater understanding of factors influencing the price sensitivity of demand-side or DER capacity resources, and the potential uncertainties associated with the availability of such capacity resources over time in comparison to conventional generating resources.

The price-sensitivity of capacity resources is particularly interesting for DERs as these resources are likely to be more transient than centralized assets which have larger, long-term capital expenditures to lay out for investment. Furthermore, the load reductions or production associated with DERs are often competing with the customer's interests in serving its own primary operations. These factors can vary based on a variety of factors that are outside of the grid operator and reliability coordinator's purview. System Operators like the NYISO are required by the North American Electric Reliability Council (NERC) to plan to serve all loads under normal and post-contingency operations over a long-term planning horizon.[31] Transmission elements and large generators have long lives and are generally relied upon for the next ten years, with adjustments for new entrants and retirements that are required to go through structured interconnection or retirement processes. In comparison, DERs are customer-sited and may enter or exit on short notice or no notice. This could create considerable uncertainty regarding transmission security and resource adequacy for the bulk system.

Similar Studies on Ancillary Resource Needs for Variable Centralized Generation Should be Considered for DERs

Increased volatility and forecast uncertainty from DERs could result in the need for additional ancillary service resources. Flexible, quick-response resources under ISO/RTO dispatch help meet imbalances caused by deviations from expected conditions (stemming from forecast errors) or help react to planned but rapidly changing system conditions (such as fast-paced upward or downward ramps in non-dispatchable resources). The form of these ancillary services may vary depending on the mix of DERs, mix of centralized generation, and ISO/RTOs preferences regarding approaches to integration.

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[29] Reflects the average vintage of U.S. coal plants (38 years) than modern coal plants. Available online at: http://www.iea.org/publications/insights/CoalvsGas_FINAL_WEB.pdf

[30] J. Newcomb, V. Lacy, L. Hansen, and M. Bell with Rocky Mountain Institute, Distributed Energy Resource: Policy Implications of Decentralization, 2013. For more information, see: http://americaspowerplan.com/site/wp-content/uploads/2013/09/APP-DER-PAPER.pdf

[31] NERC TPL Standards (http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United States)

To date, there has been limited publicly available research done on the potential resource requirement needed under different scenarios of DER adoption and scenarios of ISO/RTO generation mix. While some studies have been done on the potential for individual DERs to provide ancillary services, few studies are available that discuss the ability of DERs to meet ancillary services under aggregated scenarios of DER adoption or ISO/RTO generation mix.

In 2012, DNV GL did conduct a study with the CAISO on the impact of DERs on load following and regulation requirements under future scenarios of centralized variable generation and DER adoption.[32] The study also explored the role of visibility into the resources on the load following and regulation needs. The results underscore two important findings:

1. DER types contribute differently to ancillary resource requirements, due to differences in their variability and impact on forecast uncertainty. These, in turn, can depend on their applications and the specific DER technologies themselves
2. Increased visibility of DERs could potentially help mitigate ancillary resource requirements

What is Required for Successful DER Integration?

The Integration of DERs Must Maintain Grid Stability and Power Quality for all Customers.

To provide reliable power of a given quality, grid operators have operational requirements they must follow and are constrained in how they can balance supply and demand. The application of DERs must be considered in light of these constraints. For example, distribution grid operators are required to provide voltage service within a limited range and in some states, such as New York, utilities are also subject to service reliability and quality standards among others.[33] At the bulk level, all balancing authorities are required to meet reliability standards as defined by NERC which define requirements for planning and operating the bulk power system.[34] For example, all balancing authorities are required to meet the NERC Resource and Demand Balancing Performance Standards that describe how balancing authorities must manage system frequency and power flows in and out of control areas. Therefore, to provide reliable power of a given quality, grid operators have operational requirements they must follow and are constrained in how they can manage production and load. The application of any technologies, including DERs, must be considered in light of these constraints which are designed to ensure grid stability and power quality for all customers.

Despite the Current Challenges Associated with DER, Several Initiatives Could Help Mitigate Challenges.

Increased DER monitoring could potentially reduce forecast error by updating forecast models with current information. Increased monitoring could provide more information on the underlying drivers of variability in net loads, facilitating more accurate predictions of net load. Furthermore, increased control, or incorporation of DERs into the market, could help reduce variability by allowing ISO/RTOs not only to see the resources, but actively dispatch them as well. Efforts to reduce forecast error in solar production have been growing in

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[32] DNV GL and CAISO, 2012. Available online at: http://www.caiso.com/Documents/FinalReport-Assessment-Visibility-ControlOptions-DistributedEnergyResources.pdf

[33] "ANSI C84.1 - Electric Power Systems and Equipment - Voltage Ratings (60 Hertz)" specifies the nominal voltage ratings and operating tolerances for 60-hertz electric power systems above 100 volts; For more information on New York requirements, see: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/83026A47E9CCFBC485257687006F39CB?OpenDocument

[34] A listing of NERC reliability standards is available online at: http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf

the United States. However, methods are still being developed and approaches have not developed as fully as for wind forecasting.

The ability to incorporate demand response resources into the market could also potentially help limit forecast errors and minimize the creation of price spikes. Alternatively, the ability to estimate price response or to have greater visibility of the resource could potentially help too. Incorporating DER operations into the market directly may ease the ability to forecast behavior, as information about behavior would be more readily available. For example, information about demand response resources that are dispatched by ISO/RTOs are generally incorporated back into the real time load forecasts. In addition to facilitating ISO/RTO direct modeling of such resources, and incorporation to dispatch algorithms, market participation means such resources can also receive compensation for their contribution.

Greater visibility and control ultimately increase the information that the system operator has to work with – allowing operators to prepare flexible resources for addressing aggregate variation in the load profile in a manner similar to approaches for integrating centralized variable supply resources. There are additional challenges around DER visibility and control, however.

What Precedence Exists for Integration of DERs and What Adjustments are Currently Underway?

Integration of Demand Response and Energy Storage Provides a Starting Point for Integrating DERs into the Wholesale Markets

Today, ISO/RTOs do not explicitly specify DERs as a resource category in their market rules. Rather, most DERs participate in the markets as either demand response resources, where they modify customer loads, or as production resources that inject power into the grid.

Currently, the majority of behind-the-meter DERs that participate in wholesale markets do so as demand response resources, facilitating load reduction. This includes resources that have the flexibility to increase or decrease consumption in response to an economic and/or a reliability signal received from the system operator. Some of these resources use back-up generation to provide the service, switching their power supply from the grid to the distributed generation resource during demand response events. In those situations, there are various standards and rules across the regions on how to account for the production of the distributed generation resource, and how to calculate the baseline for performance and compensation analysis.

Energy storage has been participating in ISO/RTO markets for a number of years now. Rules for participation vary by ISO/RTO. However, many have made modifications to market rules in recent year. Two notable changes include:

- Rule adjustments to include non-generating or limited energy resources; and
- Modifications to payment approaches in ancillary markets based on performance.

In many markets, DER assets must elect to operate as a demand response resource, a production resource, or a storage resource. In NYISO, on-site generation must meet eligibility requirements to participate in emergency programs such as the NYISO's ICAP/SCR program.[35] A local generator that is normally operating

[35] The NYISO's ICAP/SCR program allows demand resources to offer Unforced Capacity ("UCAP") in the Installed Capacity ("ICAP") market. SCRs participate through Responsible Interface Parties ("RIPs"), which serve as the interface between the NYISO and the resources. SCRs that have sold ICAP are obligated to reduce their system load when called upon by the NYISO. In addition to a capacity payment, RIPs are eligible for an energy payment during a demand response event.

to partially serve its load may participate in the program with incremental capacity that is available to operate at the direction of the NYISO in order to reduce the remaining load being supplied from the transmission or distribution system. Any incremental capacity in excess of the total host load is not eligible to sell into the NYISO markets. However, excess energy may be eligible to be sold to the local distribution utility, via its retail or FITs. Resources that use local generation must have an integrated hourly meter that is either installed to measure the output of the generator or interval metering of the total net load. For SCRs, the generator must comply with the United States Environmental Protection Agency's Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines rule and the New York State Department of Environmental Conservation.

Meaningful Measurement and Verification is Important as it Provides the Basis for Fair and Transparent Financial Flows to and from Market Participants or Ratepayers and Can Support Other Operator Functions

Today, measurement and verification of demand response is used from enrollment to settlement of demand response and may also be used in planning processes. In the customer enrollment phase, the resource's capability needs to be determined, i.e. the 'unit capacity.' For operations and dispatch, the expected performance of the resource needs to be evaluated, i.e. the 'available capacity.' This is often based on past history and can vary with weather, time of day or other conditions. For financial settlements, the nominal reduction provided in each interval of an event needs to be calculated, i.e. the actual load reduction delivered. Typically, this is calculated from the difference between actual usage and an agreed baseline calculation, but may also be based on statistical sampling of a randomly selected control group in the case of mass market aggregators. For planning purposes, it may be useful to project the future performance of an individual resource, based on its past performance relative to its capability, or estimate the impact of a program, product or aggregated resource as a whole. Having the information necessary to measure and verify participation of demand response resources that are treated as supply is vital to an efficient market. Paying demand response for its ability to provide a reduction affects both loads and conventional suppliers: payments to demand response are allocated to the loads and unresponsive or phantom demand response displaces conventional supply resources.

Telemetry and Metering Provide the Means for Monitoring and Settling Demand Response Resources in the Markets

Any dispatchable resource that directly participates in a wholesale market, regardless of the market structure, must comply with dispatch signals received from the ISO/RTO and must be metered in order to be compensated for the service it is offering. Here, metering systems can be used for notification as well as for settlement. For demand response resources, a baseline demand is typically calculated to determine the amount of demand response that can be provided in any given hour. Changes in demand are compared to this baseline and measured and verified through a procedure established by the system operator. Each ISO/RTO has a set of rules and standards around metering and communication requirements and accuracy for behind-the-meter resources such as load curtailment, load modifiers, and production resources in their respective markets. In most ISO/RTOs, telemetry is required for participation in the regulation market. Some others require it for spinning reserves as well.

The primary use of metering at the utility level is for financial settlements. Utility requirements for metering are varied, and often are tied to the financial settlements negotiated between customers with DERs and the grid. There are well established precedents for using meter data for financial settlements at the utility level for distributed generation such as CHP and PV, related to net metering, FITs or other special tariffs. In recent years, the advancement of metering technologies has made it possible for utilities to communicate with customers via meters or to collect data on a range of time intervals. In turn, such advancements have allowed utilities to use advanced metering for purposes beyond billing, such as for grid operations. For example, some utilities are looking for advanced metering systems to help manage dynamic conservation voltage reduction controls. These advanced meters are also supporting customer participation in the wholesale markets.

In general, the requirements for metering are specified separately at the retail level and the wholesale level. In some cases, participation in retail or wholesale market programs will require metering that is more advanced than the basic revenue meter. For example, some wholesale market programs require sub-hourly interval readings. With the increased deployment of advanced metering capability, and the use of common standards for specifying eligible metering technologies, it is feasible that this discrepancy between retail and wholesale metering requirements could diminish over time. However, meter requirements and access to meter data is a complex issue that will need to be addressed in order to allow for seamless integration envisioned for DERs.

Telemetry of grid resources enables system operators to monitor loads, production, and other operational information to ensure reliable and stable operation of the power grid. Resources that are eligible for programs that dispatch them on a frequent basis, such as real-time market products, are generally required to have sufficient telemetry and capability as defined by the ISO/RTO. Requirements vary by the size of a resource and the type of market in which it participates.

Additional Modifications to Current Approaches around DERs are Being Considered

In principle, there exists a wide-range of wired and wireless communications options capable of meeting the needs of various DER monitoring and control strategies, and DER deployment/disposition, in both licensed and unlicensed frequency bands using public as well as privately-owned networks. What is needed to select a communications architecture infrastructure is a more complete definition of the services and service requirements that drive the communication needs. For DER supplying grid support and employing advanced control strategies it is perhaps more useful to characterize telemetry solutions in terms of the operating and control scenarios that drive the communications needs.

More utilities and many ISO/RTOs are contemplating the role of telemetry versus metering in their operations, planning, and settlement processes. Accuracy requirements are typically different for revenue metering and telemetry; however, cost considerations might allow for the use of the same equipment for both functions. At the same time, the correct choice of equipment for telemetry purposes is vital to the performance of the system. Given recent advancements in metering technology, and growth in the number of smaller assets participating in the markets, many ISO/RTOs are reconsidering requirements around metering and telemetry in the markets. Advanced metering, telemetry, and communication equipment and processes can be expensive. As the accuracy and interval frequency of the communication requirements increase, the costs also increase. The share of telemetry costs relative to the total costs of capacity will be greater for smaller assets like DERs as compared to traditional centralized generating assets for the same telemetry requirement. The challenge is to identify the rules that obtain the greatest telemetry benefits in terms of visibility, security and controllability of such resources, while balancing the cost and administrative activities.

2 INTRODUCTION

2.1 Study Objective, Scope and Approach

This study is intended to provide a comprehensive review of Distributed Energy Resource (DER) technologies, market potential and drivers, regulatory and environmental policies, and treatment in other balancing authority and utility regions. In particular, the objectives of this study are to:

- Categorize DER technologies;
- Identify DER uses and configurations;
- Describe regulatory and market-based drivers for DER adopters;
- Detail current and potential DER market penetrations in New York; and
- Assess the treatment of DERs in other ISOs/RTOs and utility regions in their various forms.

As a compilation of factual information relevant to DERs, this study serves as a starting point for discussions about DERs. The report is not intended to offer recommendations regarding DER integration, market design, or policy, nor was there detailed analysis completed to assess the effects of DERs or DER policies specific to New York. Rather, the study intends to highlight issues relevant to DER for further consideration, and to summarize national, state, and local facts and information about DERs and the lessons learned to date in New York and other jurisdictions.

In developing this study, DNV GL derived information from a combination of resources, including:

- Public studies and data;
- Discussions with stakeholders; and
- Internal expertise and analysis.

2.2 Study Definition of Distributed Energy Resources

For this study, DER technologies are defined as "behind-the-meter" power generation and storage resources typically located on an end-use customer's premises and operated for the purpose of supplying all or a portion of the customer's electric load, and may also be capable of injecting power into the transmission and/or distribution system, or into a non-utility local network in parallel with the utility grid. These DERs includes such technologies as solar PV, CHP or cogeneration systems, microgrids, wind turbines, micro turbines, back-up generators and energy storage. Some, including the PSC, have defined DERs more broadly to include energy efficiency and demand response.[36] While these are important programs that can contribute to grid reliability, this study is focused more narrowly on distributed resources capable of injecting power into the grid, as these have been evolving at a rapid pace in recent years and are less-well understood by the NYISO.

In addition, the term "behind-the-meter" is meant to represent resources that are generally not connected to the bulk electric system, or are operating primarily for the purpose of selling into the bulk electric power system. There are resources that are not behind an end-use customer's primary meter (for example, a remote-net-meter) or in other configurations that are not physically "behind-the-meter" but that would fall

[36] "Reforming the Energy Vision" NYS Department of Public Service Staff Report, Case 14-M-0101, April 24, 2014

under the intent of this study. These types of configurations are not meant to be excluded other than for the purpose of brevity.

2.3 Report Outline

The study begins with an assessment of the applications and customer motivations for DERs. It explores both the benefits and challenges of DER adoption. The study follows in Section 4 with information about the state of DERs today, detailing technology capability and cost trends, today's market penetration, the technical potential, and environmental requirements. Because retail rates and government incentives can have a significant impact on customer decisions around DER adoption and operations, the study continues in Section 5 with information about retail rates, regulations and government incentives. Furthermore, this section explores the roles these incentives have on DER adoption and operation, and provides some sample use cases of customer economics to highlight the effect of policies and incentives. Finally, the report concludes in Section 6 by describing how DERs currently fit within the context of today's wholesale markets, identifying relevant market and business rules and practices related to DER, noting metering approaches and uses, and telemetry requirements, and highlighting the role of measurement and verification.

3 BEHIND-THE-METER APPLICATIONS AND CUSTOMER MOTIVATIONS

3.1 DER Applications & Benefits

DERs create opportunities for customers to self-provide energy, manage load profiles, improve power quality and resiliency, and help meet clean energy goals. At the same time, DERs can also potentially enhance the grid as a whole. Key motivating factors for the adoption of DER, for both customers and the grid, are often described with the following categories:

- **Economic Benefits.** Avoided costs, increased efficiencies, and gained revenues. For customers owning DERs, benefits can be tied to incentive payments as well as avoided costs associated with electricity bills. For utilities, regulators, and ratepayers, benefits can be tied to more efficient utilization of the grid and deferred investments.
- **Deferred or Avoided Network Investments.** Avoided expansion of generation, transmission, or distribution facilities. This benefit applies to the grid which can indirectly benefit all ratepayers. Apart from providing economic benefits, DERs can also help avoid lengthy siting processes or can provide options where technical challenges exist around traditional capacity expansion. In some cases, the utilization of DERs can provide a quick or novel means for addressing grid challenges
- **Resiliency and Power Quality.** Uninterrupted service in the event of loss of grid service and the ability to ride through transient and short-term interruptions. This can be applied to both customers who seek to reduce outage times or power quality events, and the utilities that are coordinating outage recovery efforts and managing grid power quality.
- **Clean Energy.** Social, regulatory, and economic reasons to invest in low or no-emission DERs. Many customers are motivated to purchase clean DERs to support clean energy goals. Likewise, many utilities are doing the same, often motivated by goals or explicit targets. The net effect on emissions, however, has to be investigated per system because the displacement of centralized generation can have different effects on total emissions.

The interpretation of these values for a given customer or for a given portion of the grid depends greatly on the customer’s needs and on the circumstances of the grid. Customer circumstances include:

- individual preferences and needs, including preferences for renewable energy or need for increased reliability or higher power quality;
- economic circumstances, including the expected payback period, the ability to engage in financial transactions to acquire an asset, and the ability access government incentives; and
- the nature of the agreement(s) in place with grid operators or service providers regarding tariffs, interconnection policies, program incentives, or program participation.

Benefit streams commonly attributed to DERs include:

- energy and demand bill management (avoided costs);
- power outage mitigation or critical power support during power outages (resiliency);
- power quality improvement (enhanced reliability);
- direct compensation by grid operators or providers for services (revenue); and

- financial incentives as defined by local, state or federal policymakers (avoided costs or revenue).

The performance of a DER can also depend significantly on:

- the physical location of a customer and asset;
- a customer's end use profile; and
- the presence of other behind-the-meter technologies or capabilities such as demand response or generation assets.

Often, the factors noted above are intertwined. For example, in addition to affecting DER performance, customer location can correspond to available tariff or incentive offerings and local climate can influence end use profiles. The net effect of localized conditions is a diversity of adoption across the United States and within states. As an example, Figure 3-1 illustrates the diversity of installed capacity of PV units less than 2 MW across the United States in average capacity per person.

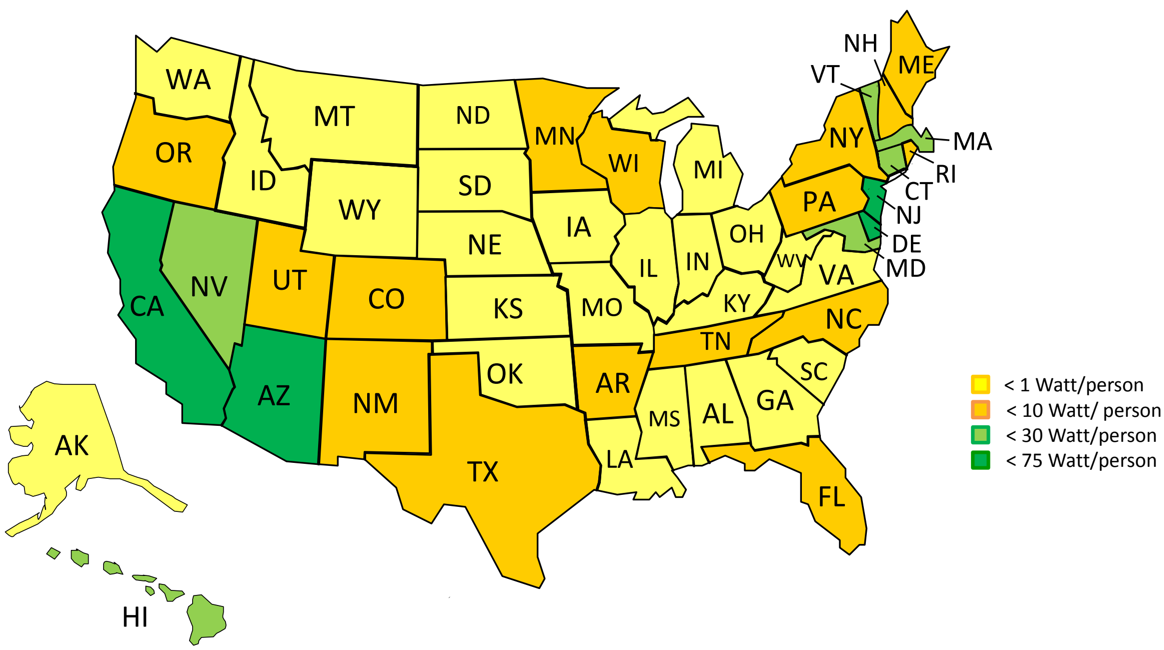

Figure 3-1. Installed PV Capacity (MW) by State

Source: Developed with data from the U.S. Census and NREL Open PV[37]

The grid benefits of DER can also vary greatly by location and are dependent on the grid characteristics to which the units are interconnected. Common value streams identified for the grid through the managed use of DERs include:

- reduced grid losses achieved by providing power closer to the customer and by reducing peak loads;
- volt/var support achieved either indirectly or directly through the use of inverters and reactive power controls;[38]
- deferred need for generation, transmission or distribution capacity by reducing peak load;
- grid ancillary services, such as selling reserves and capacity services in wholesale markets;

[37] Available online at: https://openpv.nrel.gov

[38] For example, see Kleinberg et al 2013 and A. Zakariazadeh et al. 2014

- avoided emissions;
- improved grid resiliency by directly serving customers during outage or power quality events or potentially supporting restoration processes;
- improved energy security from increased fuel diversity; and
- avoided energy production or purchases.

The nature of these benefits, however, depends greatly on the mix of DERs on the grid and on the ability to coordinate DER activities in a way that aligns grid interests with individual customer interests. In some cases, the grid benefits naturally arise – such as with reduced peak consumption where DER output coincides with system peak. In other cases, incentives must exist for customers to take actions that benefit the grid, such customers purposefully operating DERs when the grid could benefit. These incentives may take the form of direct subsidies or incentives (such as demand response program payments) or avoided costs (such as avoided demand charges). Furthermore, they may take the form of 'static' incentives which do not vary over time (such as capacity payments) or 'dynamic' incentives which do (such as dynamic energy prices). Information provided to customers about grid conditions and the agreement(s) in place with grid operators or service providers regarding tariffs, interconnection policies, program incentives or program participation can significantly influence the net effect of DERs on the grid. In turn, these policies can potentially prompt the adoption of DER technologies and their use for grid support by improving customer economics. Furthermore, localized factors such as those listed below significantly influence the need for, and value of, those benefits noted above:

The nature of DER benefits depends greatly on the mix of DERs on the grid and on the ability to coordinate DER activities in a way that aligns grid interests with individual customer interests.

- load profiles and peak load growth;
- grid equipment age and type;
- transmission and distribution capacities;
- generation capacity and fleet make-up, including fuel use, operating costs, emissions control technology, and ramping capabilities; and
- reliability standards or market rules (such as reserve requirements and penalties for sub-performance).

For example, aggregate net load profiles and existing voltage management mechanisms influence the potential for grid loss reduction and the need for additional voltage support while peak load growth and the existing capacity of equipment affect the potential for capacity deferral.

To date, national standardized approaches for evaluating the grid benefits of DERs have not yet come into practice. Furthermore, even where a common practice may be used in a given locality, there are often disagreements about the assumptions used to estimate benefits. A review of PV cost-benefit studies by the

Rocky Mountain Institute (RMI), for example, outlines some of the input assumptions used in such studies.[39] A sample is provided below:

- fuel prices;
- carbon prices;
- power plant efficiencies, plant operations, and maintenance costs;
- loss factors;
- marginal resource characteristics (including heat rates, costs, etc.);
- transmission and distribution investment needs; and
- the price or cost of carbon.

In addition, the scopes of evaluations often differ. In some cases, studies will include analysis of factors beyond grid benefits and costs, including factors like financial and security risk or environmental and social impacts, while other studies may consider a narrower scope of benefits. The following summary graph by RMI illustrates the variation in benefit and cost factors and estimates, both regionally and within a region.

[39] The Rocky Mountain Institute report, "A Review of Solar PV: Benefit and Cost Studies" summarizes factors taken into account across several PV cost-benefit studies, and illustrates how and why such studies differ.

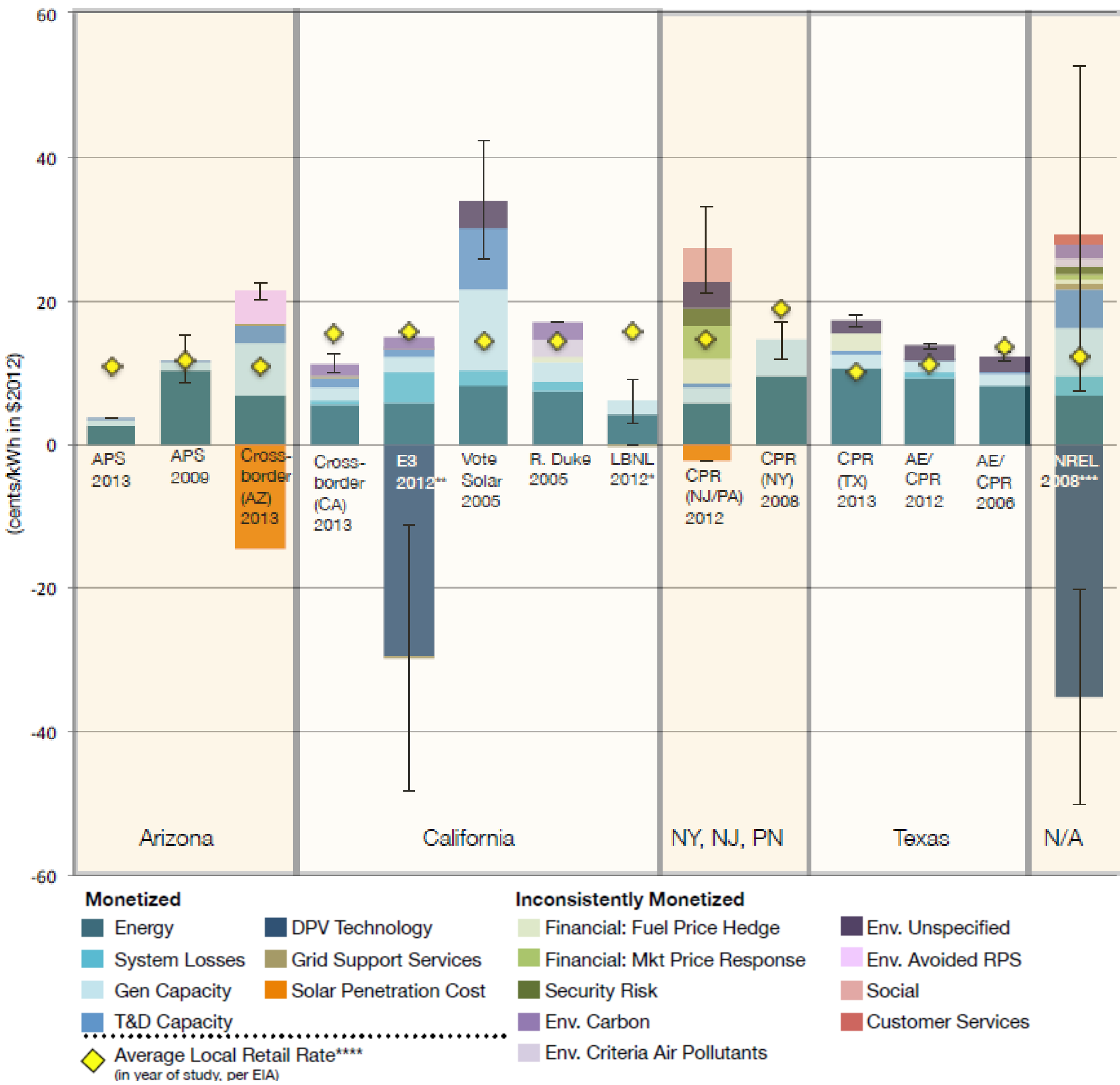

Figure 3-2.Benefits and Cost of Distributed PV by Study

Source: RMI 2013[40]

3.2 Challenges and Constraints

Though often referred to as a category, DERs represent a range of technologies with different performance characteristics. As such, DERs are often best suited to different grid and customer applications. Furthermore, as many of the applications depend on customer load profiles, different DERs are best suited to different customer types. The variation in grid, economic, and emissions impacts also result in resources facing different challenges in the marketplace. As a result of performance and application differences, they quite often have different challenges and constraints as well. The following describes some of the variability of the DERs in terms of load impacts and market challenges, and highlights some of the common themes for challenges to DER market growth. Section 4 provides additional detail regarding the capabilities and performance of different DER technologies.

[40] Available online at: http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue

DERs have the potential to significantly alter net load profiles. Depending on the controls in place, DERs can increase the price elasticity of demand. For example, customers can potentially use assets like energy storage to take advantage of lower off-peak prices by shifting loads across time and ease the response to demand response calls. Even without increased elasticity, DERs can create unique net load shapes. Figure 3-3 illustrates sample net load shapes by DER type. In reviewing these load shapes, two facts become apparent: 1) the effect of DERs on load shapes vary significantly across DER technology, and 2) DERs can significantly alter 'traditional' load shapes, either increasing or reducing peaks, and potentially adding more variability in the load shape across hours. Combinations of DERs behind the meter are feasible as well, such as with microgrids, creating the possibility for additional variations in net load profiles.

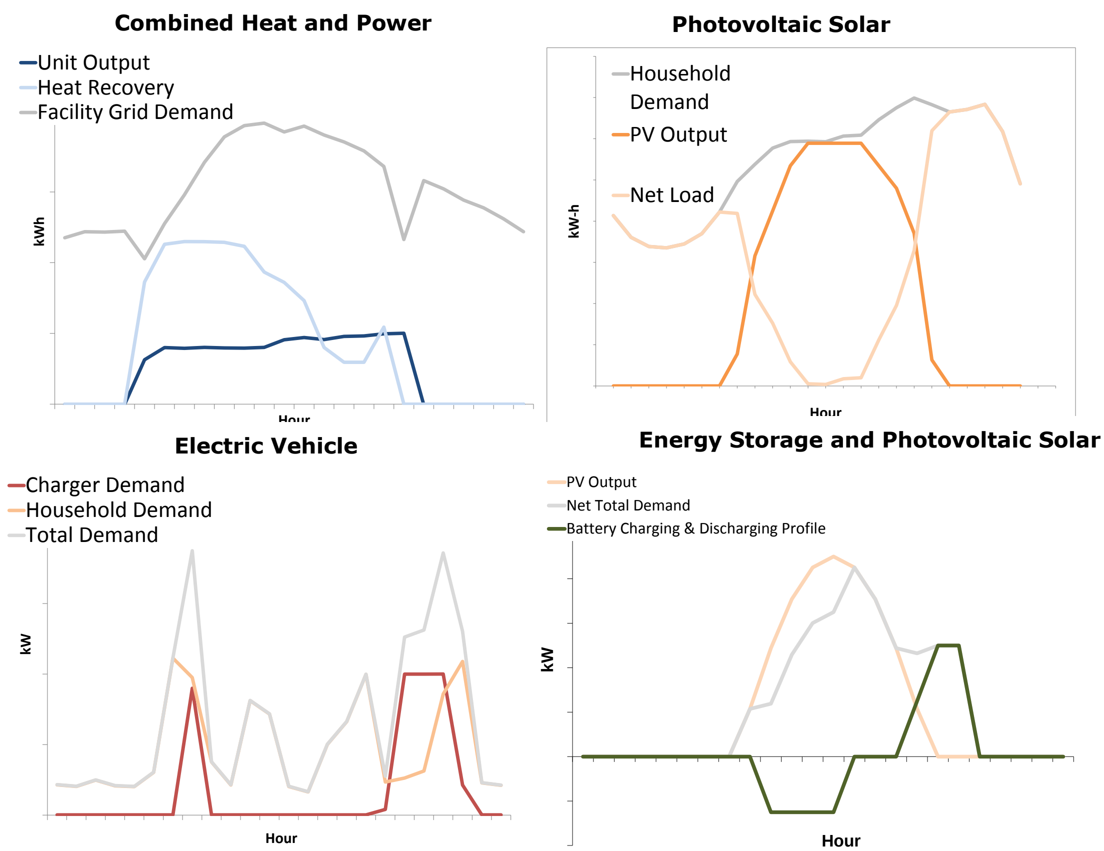

Figure 3-3. Sample DER Profiles by DER Type

For reference to standard sample load profiles without the influence of behind-the-meter assets, Figure 3-4 presents average load profiles per sector derived by NYSEG.[41]

[41] Profiles represent average profiles per segment and rate class, from NYSEG, including SC1, SC2 and SC7-1. For more information, see: http://www.nyseg.com/SuppliersAndPartners/electricityescos/loadprofiles.html

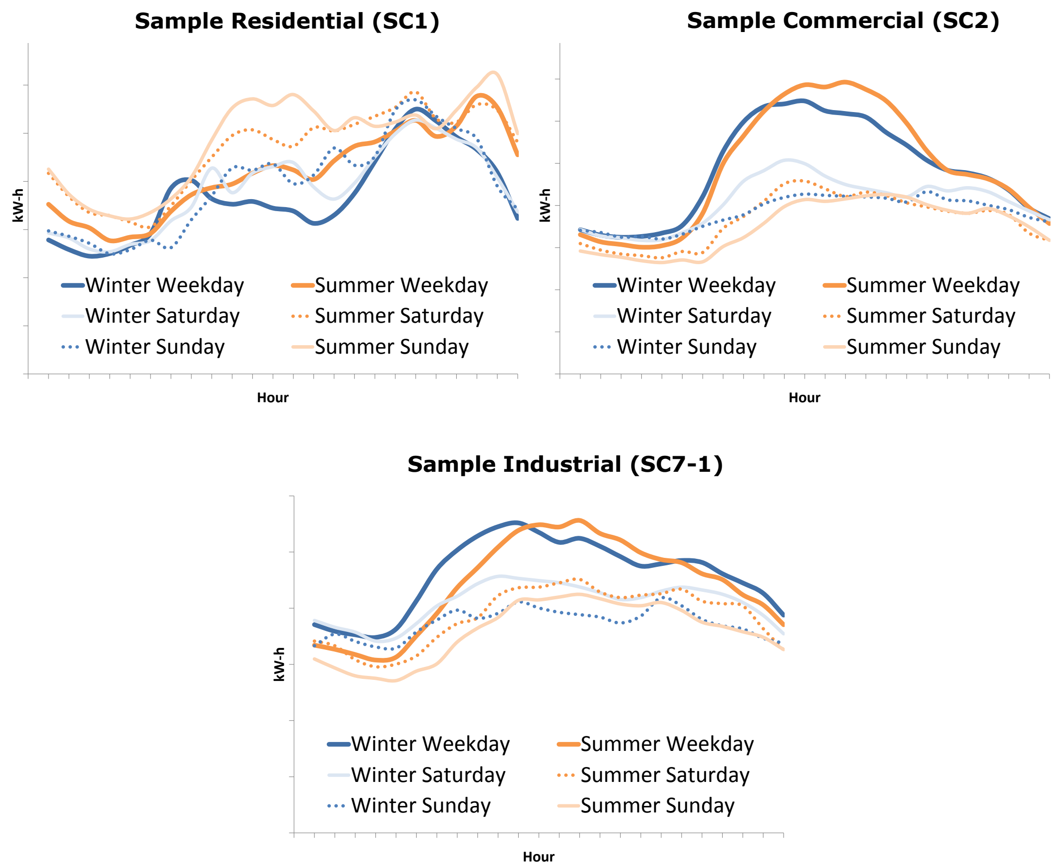

Figure 3-4. Sample Standard Load Profiles by Sector

Source: NYSEG 2003, Viewed May 2014

The modified load profiles of individual applications will depend on the customer's original profile and the services being provided by the asset. Modified profiles can range from highly variable across time, such as where intermittent resources have no means for dispatch or control, or relatively continuous across time, such as the continuous use of a controllable distributed generation (DG) asset like combined heat and power (CHP). Therefore, the net effect on the grid will depend on the DER type, its capability, and the application for which the asset is being used.

The net effect of DERs on the grid will depend on the DER type, its capability, and the application for which the asset is being used.

Despite their potential benefits, many challenges remain in the marketplace for greater adoption of DERs. Challenges for DER adoption in the market include:

- Complexity of policies, requirements and tariffs across jurisdictions, including
  - Interconnection standards;
  - Siting and permitting requirements; and
  - Utility tariff agreements and eligibility.

- Determining fair compensation for the benefits of DERs to the grid, including which parties should receive financial compensation and how much. The benefits of DER can accrue to different stakeholders complicating the ability to identify compensation for these resources for their actions and thereby justify customer investments through potential revenue streams.
- Engineering can be costly and complex if no turn-key solution is available.
- Financing can be difficult to obtain, particularly where technologies are still gaining experience in the market or where no turn-key solutions are available.
- Customers must weigh the payback of investment in DERs versus the payback from investment in their core business.
- Environmental and safety requirements can limit the installation or operations of some DER assets depending on their emissions profile or chemical make-up.

In many cases, financing, engineering, and interconnection can vary by DER type, even where installations are occurring on a single site for a single customer. For example, CHP is a technology with more experience in the market and well known potential and pitfalls, as compared to some new battery energy storage technologies which have less experience. A longer record of performance makes it easier to finance equipment. In addition, rules about the treatment of storage assets are evolving. For example, where PV might be paid under a net metering tariff, rules about payment for energy storage paired with PV often vary or are unclear.[42] Other aspects that can vary by resource include environmental requirements. For example, PV can avoid emissions on a customer site while CHP will have some emissions per kWh produced. The emissions output (or fuel inputs) for DER technologies can influence what environmental regulations they may be subject to. Additional detail on interconnection and environmental requirements as applicable to DERs is available in Section 4 and Section 6. Overall, as regulations and policies around interconnections, tariffs and program participation influence benefit streams, these policies along with government financial incentives, permitting requirements, and environmental requirements can significantly impact the cost and viability of DER adoption.

3.3 Looking at the Larger Picture

Electricity is one of the few commodities in the modern world that must be produced, distributed and delivered in real time to meet demand. Though the increased deployment of storage technologies on the grid can increase flexibility in the system, grid operators must ensure continuously and precisely balanced demand and supply in real time.[43] Furthermore, apart from needing to manage real power demand in real time, grid operators must also manage other constraints. For example, bulk system operators must ensure that there is sufficient reactive power to maintain voltages and sufficient reserves to rebalance the system in the event of a contingency. Distribution grid operators are required to provide voltage service within a limited range, and in some states, such as New York, utilities are also subject to reliability and quality

[42] For example, California Public Utilities Commission published in April of 2014 a proposed decision to clarify that qualified energy storage devices paired with qualified renewable resources are exempt from interconnection application fees, supplemental review fees, costs for distribution upgrades, and standby charges when interconnecting under the current NEM tariffs. See http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M089/K641/89641289.PDF for more detail.

[43] An example of increased storage deployment is the support of new energy storage projects by the American Recovery and Reinvestment Act (ARRA) totaling 537 MW in capacity. http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/FINAL_DOE_Report-Storage_Activities_5-1-11.pdf

standards among others.[44] At the bulk level, all balancing authorities are required to meet reliability standards as defined by Electric NERC which define requirements for planning and operating the bulk power system.[45] For example, all balancing authorities are required to meet the NERC Resource and Demand Balancing Performance Standards that describe how balancing authorities must manage system frequency and power flows in and out of control areas. Therefore, to provide reliable power of a given quality, grid operators have operational requirements they must follow and are constrained in how they can manage generation and load. The application of any technologies, including DERs, must be considered in light of these constraints which are designed to ensure grid stability and power quality for all customers.

While certain DERs can provide grid benefits, they also potentially create challenges under current operating paradigms. For example, intermittent or variable power production can affect local voltages, creating new requirements for grid voltage management. Alternatively, excess production from DG can result in reverse power flows where aggregate DG is greater than aggregate demand. These grid effects can be managed. However certain challenges require expenditures to solve, such as re-conductoring lines, installing additional breakers and capacitors, and upgrading transformers and tap changers. To the extent that grid planning and operations and customer adoption and operation of DERs can be aligned, it is feasible that these problems would be mitigated or at least reduced such that DER benefits would outweigh integration costs. As such, policy and regulatory structures will be key to aligning interests and maximizing benefits for all parties.

Apart from the direct consequence of DERs on grid functions, DERs potentially could create unintended effects which need further exploration. For example, DERs have the potential to reduce electricity sales volumes while maintaining or increasing grid management functions (that help provide high quality power across the system or support DER investments). This has the potential effect of reducing the effectiveness of current utility compensation mechanisms. Most often, grid operators are compensated for their investments and operations via volume-based charges ($/kWh). Volume decreases with flat or growing costs could put an upward pressure on per unit rates in the long-term where DER grid benefits do not make up for the lost volume. Such issues can be addressed with alternative compensation mechanisms, not unlike approaches to compensation of lost volume through energy efficiency-related programs.

Issues, discussed further in Section 6, include:

- Centralized generation impacts, including production costs and portfolio characteristics, such as ramping capability, governor response, or emissions; and
- Load forecasting error and resulting resource requirements for managing this error, either in short-term planning for balancing load and demand or in long-term planning.

Ultimately, distribution, production and wholesale market implications need to be assessed further so that such issues can be resolved prior to large-scale adoption of DER. With incentive structures in place, it is feasible that DERs can enhance the grid, benefitting all ratepayers as well as the customers owning, operating or leasing DERs and the utilities supporting and coordinating this market development.

Distribution, production and wholesale market implications need to be assessed further so that such issues can be resolved prior to large-scale adoption of DER.

44 "ANSI C84.1 - Electric Power Systems and Equipment - Voltage Ratings (60 Hertz)" specifies the nominal voltage ratings and operating tolerances for 60-hertz electric power systems above 100 volts.; For more information on New York requirements, see: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/83026A47E9CCFBC485257687006F39CB?OpenDocument

45 A listing of NERC reliability standards is available online at: http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf

4 STATE OF DISTRIBUTED ENERGY RESOURCES

4.1 Technology Assessment

The term "distributed energy resource" encompasses a variety of distributed technologies. Figure 4-1 illustrates the types of DERs considered under this study. Combinations and variations on these technologies are feasible, including microgrids and CHP.

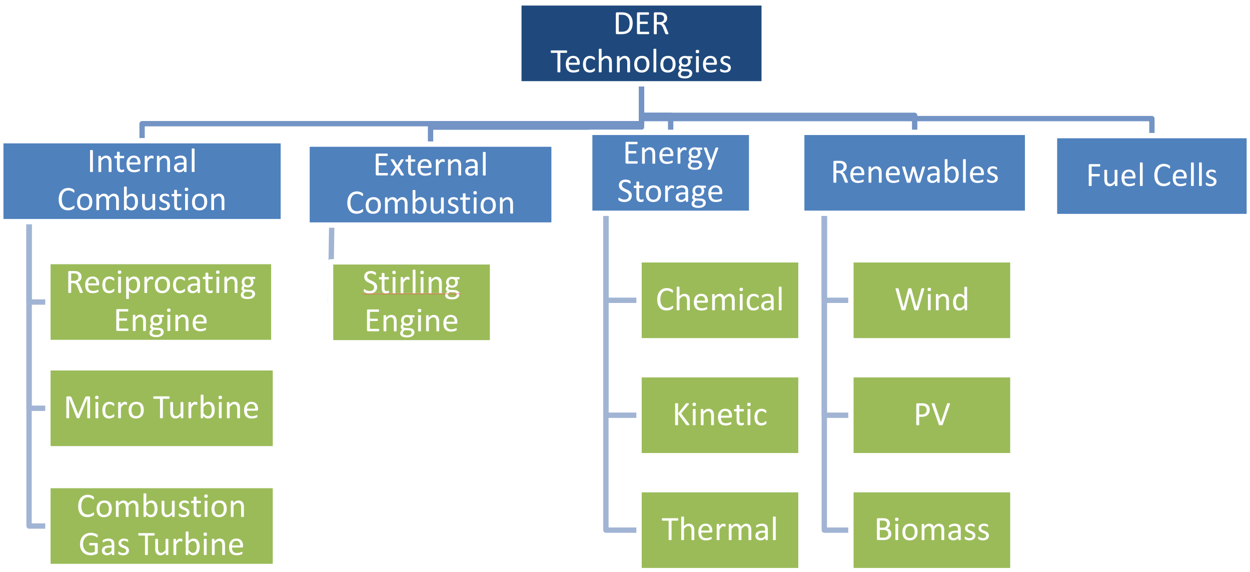

Figure 4-1. DER Technologies

The following sections outline technology characteristics and how they relate to potential applications for DERs, and note the relative level of development and maturity of different DER technologies in terms of cost and performance.

4.1.1 Technology Developments

DERs constitute a variety of technologies, some with more market experience and penetration than others, and some in the stages of more rapid development than others. More traditional technologies include internal and external combustion engines and CHP. CHP has seen enhancements in recent years, but costs have generally not come down as rapidly as other technologies like PV and energy storage. However, the market for CHP is expected to grow with an increased focus on resiliency and continued financial and educational outreach and support provided by state and federal programs. PV has seen rapid development over the past two decades in terms of cost and performance, as has energy storage. Expectations are that these trends will continue. While microgrids have existed on ships for decades, their implementation in the electricity grid are a relatively recent phenomenon. Today, however, commercial applications are developing. Fuel cell markets are currently growing in stationary applications globally. As with storage, there is continued focus on cost reductions and performance improvements.

DERs constitute a variety of technologies, some with more market experience and penetration than others, and some in more rapid stages of development than others.

Photovoltaic Solar

The first photovoltaic cells capable of powering commercial equipment and the first commercial licenses for PV technologies were developed in the United States in the mid-1950s.[46] Throughout the 1950s, 1960's, and 1970s the technology developed with new materials increasing performance and applications. Larger PV systems (at or larger than 1 MW) began to go online in 1982.[47] Since the 1980s, technology and manufacturing improvements, along with economies of scale, have helped bring prices down and increased performance. Today, most solar cells are made from either crystalline silicon or thin-film semiconductor material. Figure 4-2 illustrates how cell efficiencies have improved over time, by technology type.

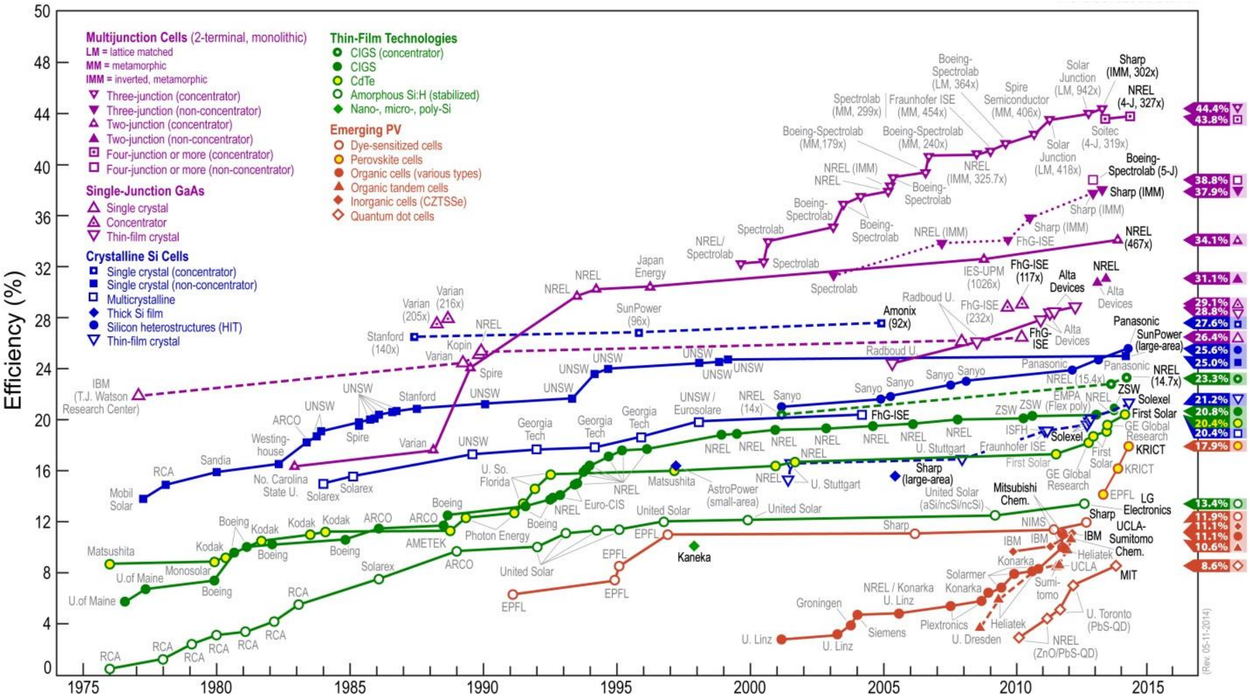

Figure 4-2. Cell Efficiencies over Time

Source: NREL 2014[48]

Figure 4-3 illustrates the reduction of average installed PV price across technologies over time as estimated by Lawrence Berkeley National Laboratory (LBNL) using a sample of 8,000 residential and commercial PV projects. The average installed prices represent prices exclusive of any financial incentives. According to LBNL's research, prices have declined by five to seven percent per year on average, with a total installed price reduction between 1998 and 2011 of 36% for systems less than or equal to 10 kW.[49] According to the Solar Energy Industries Association (SEIA), national average installed residential and commercial PV system prices dropped by 31% from 2010 to 2014, with a reduction in New York of 4% within the last year.[50]

46 DOE, "The History of Solar." For more information see: http://www1.eere.energy.gov/solar/pdfs/solar_timeline.pdf

47 Ibid.

48 Available online at: http://www.nrel.gov/ncpv/images/efficiency_chart.jpg

49 LBNL, 2012; http://emp.lbl.gov/sites/all/files/lbnl-5919e.pdf

50 SEIA, State Solar Policy, New York Solar. Viewed May 2014. Available online at: http://www.seia.org/state-solar-policy/new-york

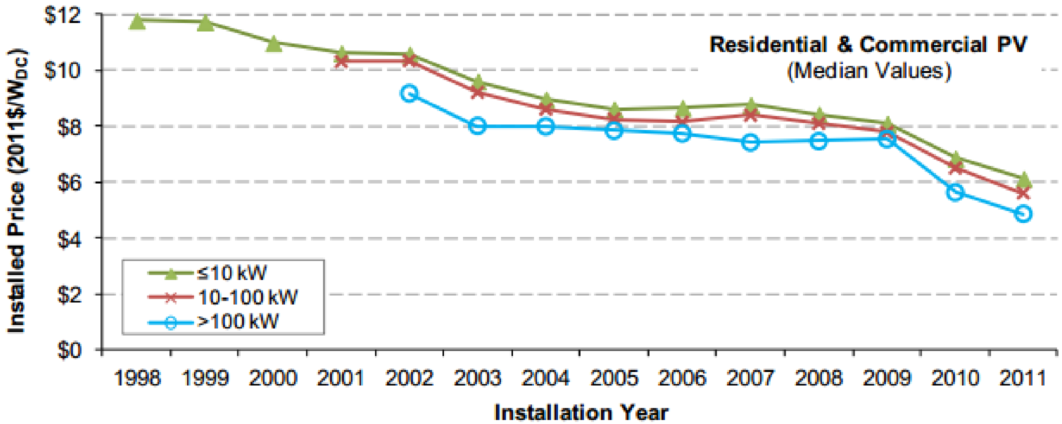

Figure 4-3. Installed Price of Residential & Commercial PV over Time

Source: LBNL 2012[51]

The source of the price reductions varied over time. According to LBNL, prior to 2005, price reductions were associated with a decline in non-module costs, such as inverters, mounting hardware, labor, permitting, inspection and interconnection, etc. According to LBNL estimates, in 2005, cost reductions stagnated due to excess demand relative to supply and after 2008, costs declined due to steep reductions in module prices. Today, many in the industry are looking towards non-module costs as a potential source for further installed cost reductions. In 2013, NREL released a roadmap to reduce soft costs by 2020, with targets of $0.65/W and $0.44/W for residential and commercial systems, respectively.[52] Figure 4-4 illustrates estimates by RMI of the typical components of system price, and compares the soft costs (which includes customer acquisition; installation labor; permitting, inspection, and interconnection costs) of average systems in the United States versus Germany.

[51] http://emp.lbl.gov/sites/all/files/lbnl-5919e.pdf

[52] For more information, see: http://www.nrel.gov/news/press/2013/3301.html

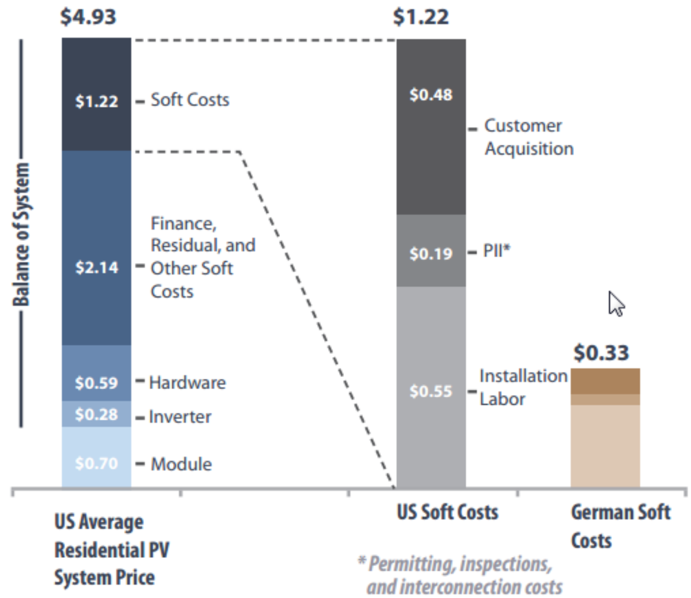

Figure 4-4. Solar PV System Costs in the U.S. and Germany

Source: RMI 2013[53]

Generally, industry experts believe that total installed costs could continue to decline. Figure 4-5 and Figure 4-6 illustrate projected cost reductions moving forward, as estimated by Bloomberg New Energy Finance (BNEF), the Environmental Protection Agency (EPA), Black & Veatch and National Renewable Energy Laboratory (NREL) and projected forward by RMI. The U.S. Department of Energy (DOE) currently has active initiatives to reduce PV installed cost, including the SunShot Initiative which has the goal of reducing residential and commercial installed costs of PV systems to $1.50/watt and $1.25/watt, respectively, by 2020.[54]

[53] Available online at: http://americaspowerplan.com/site/wp-content/uploads/2013/09/APP-DER-PAPER.pdf
[54] For more information, see http://energy.gov/eere/sunshot/sunshot-initiative

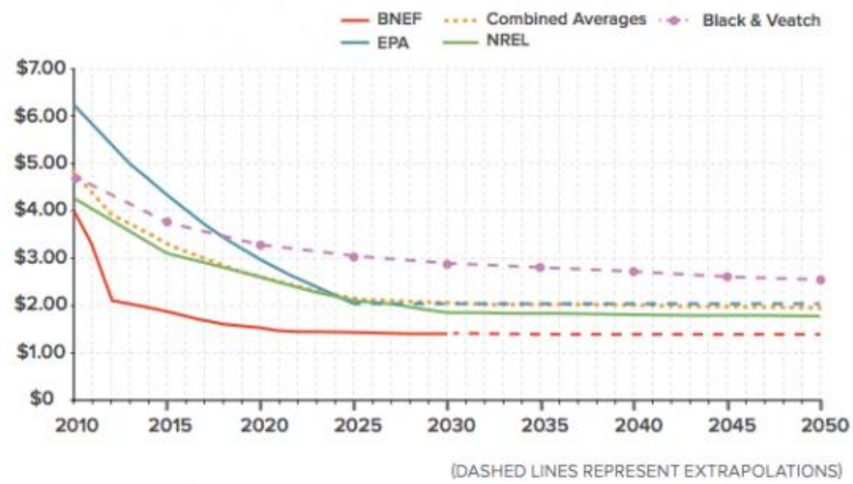

Figure 4-5. Forecasts of Commercial PV Installed Cost with Projections by RMI

Source: RMI 2014[55]

[Y-AXIS 2012$/$W_{dc}$ - INSTALLED]

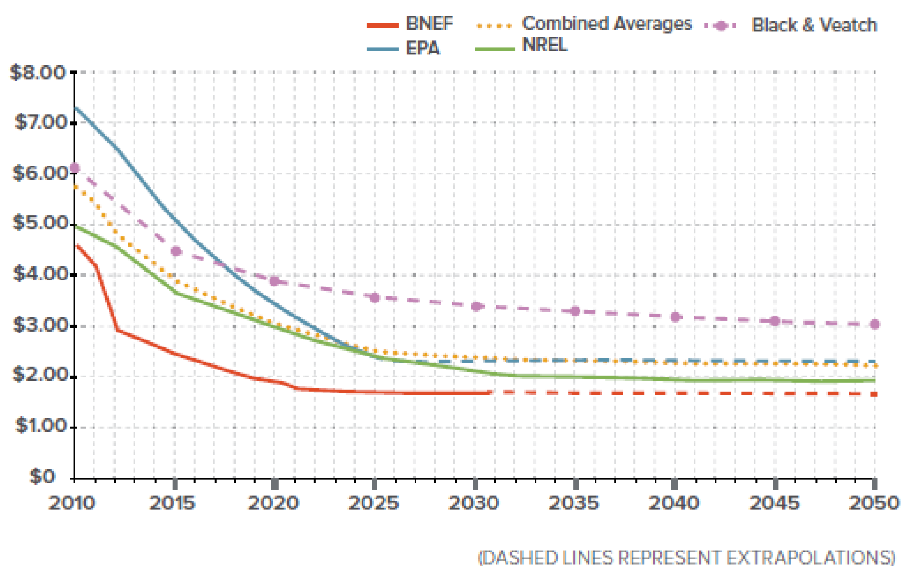

Figure 4-6. Forecasts of Residential PV Installed Cost with Projections by RMI

Source: RMI 2014[56]

Several industry experts expect that total PV energy costs could compete with retail prices for a sizeable portion of the market in coming years. Some even believe that PV could reach grid parity, where customers could cost-effectively use PV and supporting equipment to meet power needs without grid back-up.[57]

55 For more information, see: http://www.rmi.org/electricity_grid_defection

56 For more information, see: http://www.rmi.org/electricity_grid_defection

57 Today, many PV systems installed today cover only a portion of total load or have limited ability to fully balance load with self-supply entirely on the customer side of the meter, therefore requiring grid interconnection for support to meet power needs. The distinction between retail rate parity versus grid parity is the difference in such additional grid-based services.; For more information, see: http://www.rmi.org/electricity_grid_defection

Barclays, for example, this year announced their estimation that solar and storage applications are already cost competitive in Hawaii, and could also be competitive in California, New York and Arizona in the near future.[58]

Combined Heat and Power

The concept of using heat from the production of electricity was used as early as the 1880's. Since 1882 Consolidated Edison in New York City has operated the largest district heating system in the United States using waste heat from both electric generators and dedicated steam facilities to provide space heating and cooling. As larger coal-fired power plants began to move generation outside of populated areas, this practice became less economical until the 1980's. The Public Utility Regulatory Policies Act of 1978 (PURPA) promoted more efficient use of energy through a requirement that public utilities buy electricity from "cogeneration" facilities. Cogenerators are electric facilities that are co-located with a steam host, typically an industrial customer that can utilize waste steam from the electric power plant. In the 1990s, with the development of advanced combined cycle power generators, waste steam could instead be reused to manufacture additional electricity using a heat recovery steam generator. CHP, in its many forms, can enable realized fuel efficiencies to reach 90 percent.[59]

The vast majority of CHP units installed today (in New York State and in the U.S.) are greater than 5 MW, as illustrated in Figure 4-7.

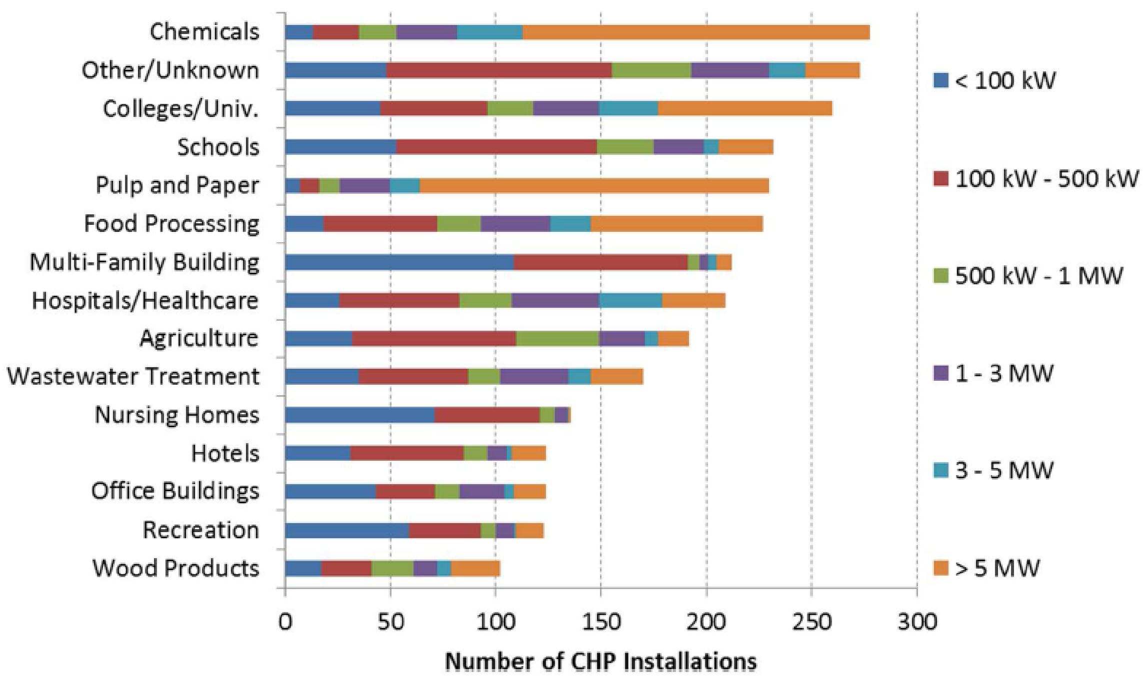

Figure 4-7. National CHP Installations by Size and Industry

Source: EEA U.S. CHP Installation Database as of January 2014

[58] For more information, see: http://blogs.barrons.com/incomeinvesting/2014/05/23/barclays-downgrades-electric-utility-bonds-sees-viable-solar-competition/

[59] http://www.ceere.org/iac/iac_combined.html

In addition, the majority of installed CHP capacity consists of combined cycle CHP units.[60] However, the majority of smaller-scale capacity is comprised predominantly of microturbines and reciprocating CHP engines.[61] All CHP technologies, combined cycle units, microturbines and reciprocating engines, are well developed technologies.

Energy Storage

Energy storage includes a variety of technologies which use mechanical, electrochemical, or thermal processes to store and release energy. The first batteries are estimated to have been developed as early as 250 BC to 224 AD, with mechanical, electrical and thermal storage technologies advancing over thousands of years.[62] In 1859, rechargeable, lead acid batteries were developed.[63] In more recent years, a variety of battery chemistries have emerged, offering a diversity of performance capabilities and costs. In 1991, Sony commercialized the first lithium-ion battery.[64] Lithium-ion battery technology has undergone some of the greatest advances in recent years, with energy density increasing approximately 5% per year and costs decreasing roughly 8% per year.[65] Overall, modern lithium-ion batteries are estimated to have doubled their energy density and become ten times cheaper in the last ten to fifteen years.[66]

There is pressure to continue cost reductions and increase battery energy density in order for stationary and transportation applications to become more widespread. Though many applications are feasible with current battery performance and cost profiles, the Joint Center for Energy Storage Research (JCESR), a public-private research partnership managed by DOE, has highly aggressive targets to improve battery performance and reduce costs further. For transportation applications, JCESR is looking to obtain a battery with a cost of $100/kWh, a lifespan of 15 calendar years and 1,000 cycles, and an energy density of 400 watt-hours per kilogram – all by 2017.[67] Goals for stationary applications include a cost of $100/kWh, a lifespan of 20 calendar years and 7,000 cycles, and round trip efficiency of 95% by 2017.[68] These are seen generally as targets that push the boundaries of what may be achievable - such performance and cost improvements will likely require new chemistries and perhaps radical re-designs. Figure 4-8 illustrates the historical change in energy density for various battery types, and the targeted density for lithium-ion batteries under the JCESR target. Estimated achievable energy densities are presented on the right-hand side of the figure as well, in watt-hours per kilogram.

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60 ORNL Combined Heat and Power Installation Database, last updated 7/25/2013.

61 Ibid.

62 R. Narayan and B. Viswanathan, "Chemical and Electrochemical Energy Systems," Universities Press 1998. Preview available online at: http://books.google.com/books?id=hISACjsS3FsC&pg=PA66&lpg=PA66&dq=batteries,+250+BC+to+224+AD&source=bl&ots=mlSO5VBKU_&sig=0vZ79-W06Uc4SNRUpHLNnTKi4K4&hl=en&sa=X&ei=8qHIU6P2JfLmsATd1YDICQ&ved=0CE8Q6AEwCA#v=onepage&q=batteries%2C%20250%20BC%20to%20224%20AD&f=false

63 Ibid.

64 Available online at: http://www.sony.com.cn/products/ed/battery/download.pdf

65 George Crabtree, Director, JCESR, Argonne National Laboratory, University of Illinois at Chicago, "JCESR: One Year Later," Materials Research Society, San Francisco CA, Apr 21, 2014

66 Sources: Van Norden, 2014. Available online at: http://www.nature.com/news/the-rechargeable-revolution-a-better-battery-1.14815#batt2; http://dukespace.lib.duke.edu/dspace/bitstream/handle/10161/1007/Li-Ion_Battery_costs_-_MP_Final.pdf?sequence=1

67 Ibid.

68 Ibid.

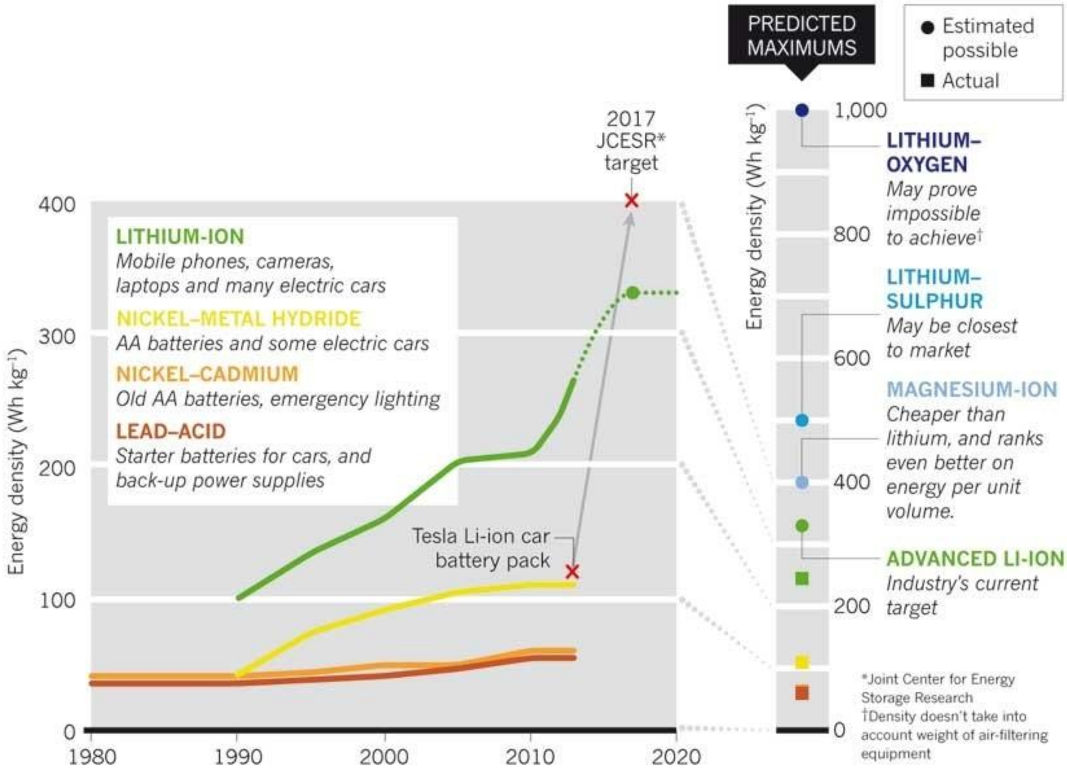

Figure 4-8. Energy Density Improvement over Time and Estimated Energy Density Maximums by Technology

Source: van Noorden 2014[69]

Figure 4-9 illustrates estimates of historical battery price reductions over time. In general, we have seen fairly steep price reductions within the past five years and lesser price reduction within the past two years.

[69] Available online at: http://www.nature.com/news/the-rechargeable-revolution-a-better-battery-1.14815#batt2

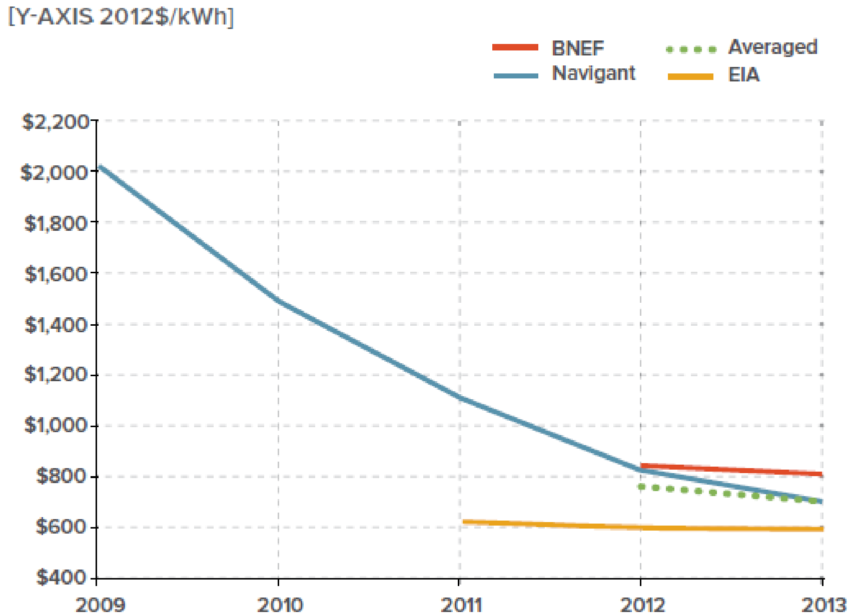

Figure 4-9. Historical Battery Energy Storage Prices

Source: RMI 2014[70]

Figure 4-10 illustrates estimates of battery price projections, gathered by RMI from different sources and extrapolated to future years. Generally, industry expectations are that there is room for further battery price reduction beyond those experienced to date.

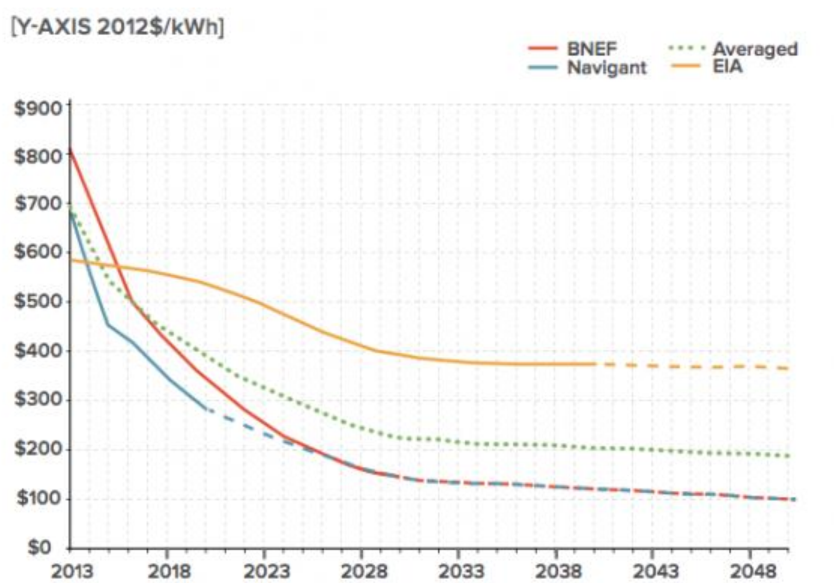

Figure 4-10. Battery Energy Storage Price Projections

Source: RMI 2014[71]

[70] For more information, see: http://www.rmi.org/electricity_grid_defection

[71] For more information, see: http://www.rmi.org/electricity_grid_defection

Fuel Cells

Fuels cells use electrochemical processes to generate electricity. Most combine hydrogen and oxygen to produce power, with water and heat produced as by-products. Though fuel cells and batteries both use electrochemical processes, fuel cells differ in that they rely on fuel sources and therefore have durations that rely on fuel supply.

Fuels cells can serve stationary and portable power applications as well as transportation applications. For power applications, units can be used as back-up power, in CHP systems, and as primary power sources. For transportation applications, units can be used in passenger and commercial fuel cell electric vehicles, in material handling equipment (such as forklifts) and as auxiliary power units for vehicles.[72] Early market applications include forklifts, backup power, and portable power applications. Applications that are expected to grow within in the midterm (2012 to 2017) include residential CHP, auxiliary power units, fleet vehicles and buses. Applications that are expected to grow within the longer-term (2015 to 2020) include light-duty passenger vehicles and other transportation applications.[73] The strongest market for fuel cells in recent years has been for applications in data centers and telecommunications facilities and as sources of power for material handling equipment.

Overall, fuel cell markets are currently growing in stationary applications globally, though domestic growth rates are much slower. Shipments of stationary fuel cells grew from about 2,000 shipments in 2008 to about 25,000 shipments in 2012.[74] However, most of the market growth is abroad rather than domestic. Transportation and portable applications have had more difficulty – with the market contracting in 2012.[75] Nevertheless, investment in fuel cells in the United States has been relatively strong and research continues. U.S. investors made the largest cumulative investment globally in fuel cells between 2000 and 2011, at $815 million.[76]

Federal funding of fuel cells has generally been consistent over the years, with the exception of 2009, when DOE invested an additional $41.9 million via the American Recovery and Reinvestment Act to help commercialize and deploy over 1,000 fuel cell systems.[77] Applications range from backup power, to portable generators for consumer electronics, to CHP, to power for material handling equipment. Though funding continues, it has contracted in the last few years. Department of Energy goals for stationary fuel cells by 2015 include a $750/kW cost target with 40% efficiency and 40,000 hour durability.[78]

Over the years, fuel cell costs have declined and durability has increased. According to DOE, fuel cell durability has more than doubled and the cost of electrolyzer stacks has been reduced by 60 percent since

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[72] DOE Office of Energy Efficiency and Renewable Energy Fuel Cell Technologies Office *2012 Fuel Cell Technologies Market Report*, 2013. Available online at: http://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/2012_market_report.pdf

[73] DOE, Hydrogen and Fuel Cell Activities, Progress, and Plans: August 2007 to August 2010; Second Report to Congress, August 2013. Available online at: http://www.hydrogen.energy.gov/pdfs/epact_second_report_sec811.pdf

[74] DOE Office of Energy Efficiency and Renewable Energy Fuel Cell Technologies Office *2012 Fuel Cell Technologies Market Report*, 2013. Available online at: http://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/2012_market_report.pdf

[75] Ibid.

[76] Breakthrough Technologies Institute. Fuel Cell Collaboration in the United States: Follow Up Report to the Danish Partnership for Hydrogen and Fuel Cells, 2013. Available online at: http://www.hydrogennet.dk/fileadmin/user_upload/PDF-filer/Brint_og_braendselsceller_internationalt/Dansk-amerikansk_samarbejde/Fuel_Cell_Collaboration_in_the_United_States_-_Follow_Up_Report_DRAFT-2.pdf

[77] DOE, Hydrogen and Fuel Cell Activities, Progress, and Plans: August 2007 to August 2010; Second Report to Congress, August 2013. Available online at: http://www.hydrogen.energy.gov/pdfs/epact_second_report_sec811.pdf

[78] Ibid.

2007.[79] Figure 4-11 illustrates historical and projected cost reductions for fuel cell units in transportation systems.

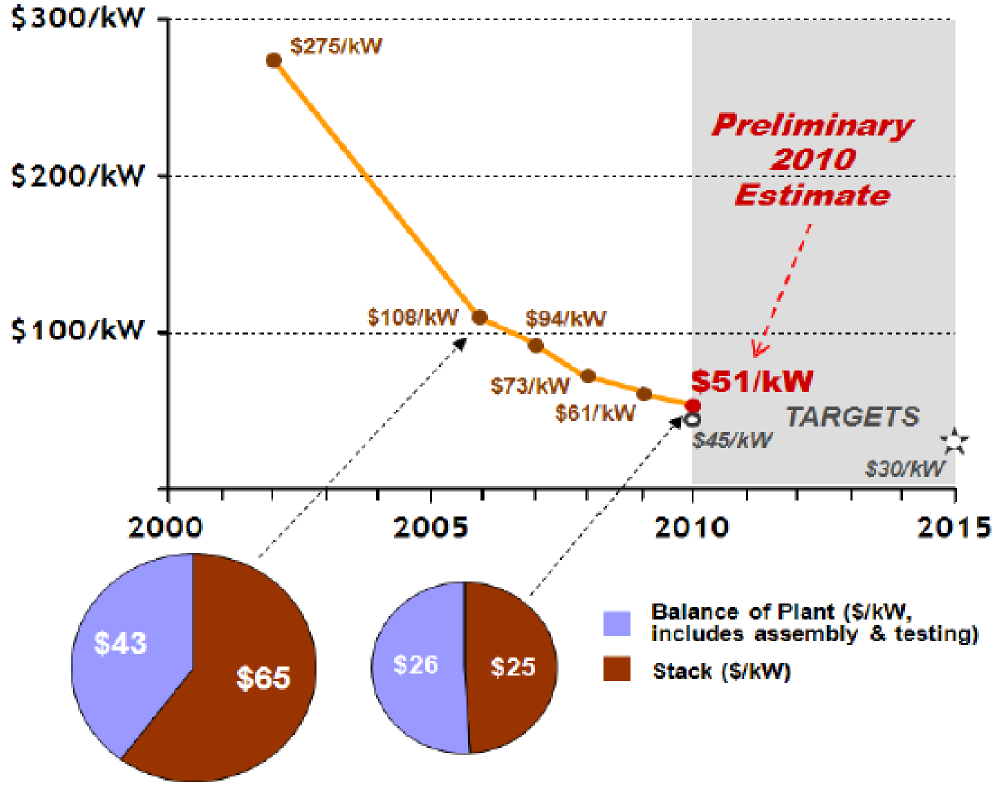

Figure 4-11. Projected Transportation Fuel Cell Costs

Source: DOE 2013[80]

Fuel cell technology continues to improve, with several recent developments taking place in the United States. Figure 4-12 illustrates fuel cell patents by country over time. The United Sates is a global leader in the number of patents for fuel cell technology.

[79] DOE Office of Energy Efficiency and Renewable Energy Fuel Cell Technologies Office *2012 Fuel Cell Technologies Market Report*, 2013. Available online at: http://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/2012_market_report.pdf

[80] DOE, Hydrogen and Fuel Cell Activities, Progress, and Plans: August 2007 to August 2010; Second Report to Congress, August 2013. Available online at: http://www.hydrogen.energy.gov/pdfs/epact_second_report_sec811.pdf

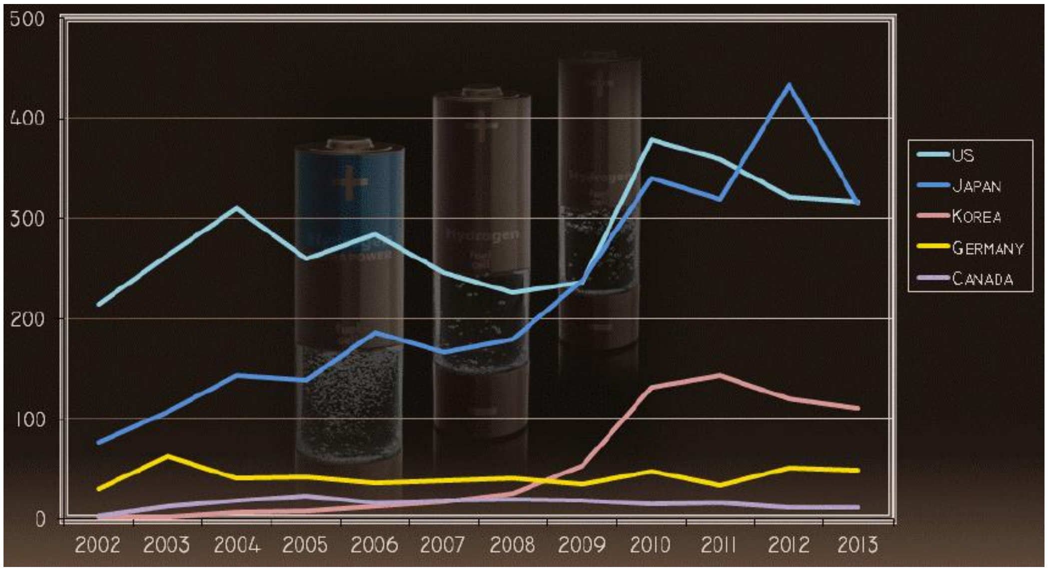

Figure 4-12. Fuel Cell Patents over Time by Country

Source: Heslin Rothenberg Farley & Mesiti P.C. 2014[81]

Figure 4-13 illustrates the percentage share of patents by U.S. state. New York sits within the top five states of number of fuel cell patents granted since 2002.

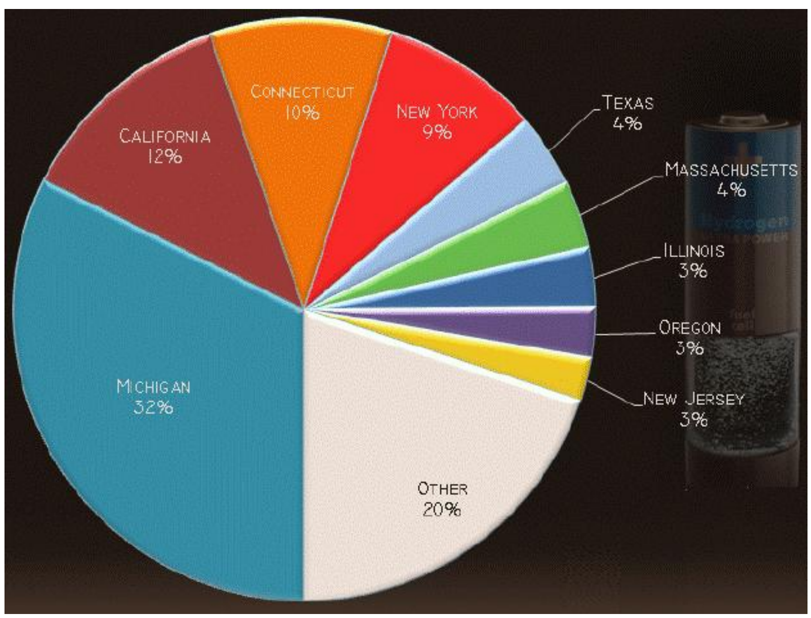

Figure 4-13. Percentage Share of Fuel Cell Patents by State

Source: Heslin Rothenberg Farley & Mesiti P.C. 2014

New York has experience with fuel cell installations dating back several years. In the 1990s, a 200 kW unit was installed at an off-grid Central Park Police Precinct which is believed to be the first such installation in

81 Available online at: http://cepgi.typepad.com/files/cepgi-2013-year-end-wrap-up.pdf

the State.[82] According to Fuel Cells 2000, 280 fuel cell units constituting 4.7 MW of capacity have been installed in New York since 2005.[83]

Microgrids

The term microgrid can encompass a variety of meanings. LBNL has defined microgrid as:

> *A group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid [and can] connect and disconnect from the grid to enable it to operate in both grid connected or island mode.*[84]

At its most basic, a microgrid can consist of a single DER sited at a single customer location that has the ability to connect and disconnect from the grid. The coordinated control of resources and grid operations across multiple resources or multiple sites can also be called a microgrid. The majority of microgrids in operation today consist of "campus-style" installations with multiple DERs coordinated within a customer site. However, the industry is actively researching, developing and demonstrating the coordinated control of resources and grid operations across multiple sites. This year, for example, New York announced $40 million competition to create community microgrids for the purpose of increasing storm resiliency.[85] The PSC, NYSERDA and the Department of Homeland Security and Emergency Services are also expected to release a study in the near term with details on the policy, technical, and economic issues around community micogrids in the state of New York.[86]

4.1.2 Technology Performance Characteristics and Application Feasibility

DERs can serve a number of applications, each of which has their own performance requirements. For example, participation in NYISO's Special Case Resource program requires a two-hour ramp period whereas regulation services require, effectively, instantaneous ramping. Figure 4-14 provides a high-level outline of duration, frequency and start-up and ramping requirements by application.

82 http://energy.gov/sites/prod/files/2014/03/f12/state_of_the_states_2013.pdf; http://www.fuelcells.org/dbs/

83 Available online at: http://www.fuelcells.org/dbs/; Fuel Cells 2000 is an activity of the Breakthrough Technologies Institute, a non-profit organization that identifies and promotes environmental and energy technologies.

84 http://building-microgrid.lbl.gov/microgrid-definitions

85 For more information, see: http://www.governor.ny.gov/press/01072013-cuomo-biden-future-recovery-efforts

86 See A.7049/Crespo; Chapter 221 of 2013

Application	Characteristics			Duration			Frequency of use		
	Islanding	Short Start-Up Time	Quick Ramping Time	Continous	2-6 hours	< 2 hours	Daily (> 2000 h)	Seasonal (500-2000h)	Yearly (< 500 h)
Continuous Power / Base Load				X			X		
Uninterrupted Power Supply (UPS)		X	X			X			X
Back Up		X			X				X
Back-up with Islanding	X			X					X
Renewables Integration			X		X	X	X	X	
Peak Shaving		X	X			X	X	X	
Demand Response		X	X		X	X		X	X
Regulation		X	X			X	X		
Reserves		X			X	X			X
Supply Capacity				X	X	X		X	X
T&D Deferral					X			X	X

Figure 4-14. DER Applications and Requirements

DER performance, characteristics, typical sizing and associated fixed and operational costs vary quite widely. For example, startup times can range from milliseconds to minutes depending on the technology. Figure 4-15 outlines typical ranges of size, cost, and performance characteristics across engines (including CHP technologies), fuel cells, storage, and PV to provide a sense of the variation of DERs. Ranges can be fairly broad due to variance in performance under different conditions (such as ambient temperature, fuel make-up, etc.) and due to different levels of optimism about technology capability.

Characteristic	Internal Combustion Technologies			Fuel Cell Technologies				Storage Technologies		Solar
	Reciprocating Engine	Microturbine	Combustion Gas Turbine	Proton Exchange Membrane (PEMFC)	Phosphoric Acid (PAFC)	Molten Carbonate (MCFC)	Solid Oxide (SOFC)	High Power e.g., li-ion	High Energy e.g., NaS	PV
Size	30kW-6+MW	30-400kW	0.5-30+MW	<1kW-500kW	50kW-1MW (250kW module typical)	<1kW-5MW (250kW module typical)	<1kW - 5MW	kWs to MWs	kWs to MWs	0.2 kW per module, could be 000s of MW
Power Density (mW/cm^2)	2,900 - 3,850	3,075 - 7,175	1,750 - 53,800	350-800	140 - 320	100 - 120	150 - 700	N/A	N/A	up to 175
Operating Temperature	450°C (850°F)	980°C (1,800°F)	1,930°C (3,500°F)	50-100°C (122-212°F)	150-200°C (302-392°F)	600-700°C (1,112-1,292°F)	600-1,000°C (1,202-1,832°F)	ambient	290-360°C	Ambient + ~20 C
Start-up Time	10s to 15 mins	Up to 120s	2 - 10 min	15 - 30 min	3-4 hrs	8 - 24 hrs	8 - 24 hrs	ms	ms	ms
Elec. Efficiency (LHV) %	30-42%	14-30%	21-40%	36-50%	37-42%	45 - 50%	40-60%	93-97%	85-90%	15%
Electric+Thermal (CHP) Efficiency %	80-85%	80-85%	80-90%	50-75%	<85%	<80%	<90%	90-94% AC	78-80% AC	n/a
Installed Cost ($/kW)	$700-1,200/kW	$1,200-1,700/kW	$400-900/kW	$3,500/kW	$4,500 - 9,000/kW	$4,200 - 7,200/kW	$3,500 - 8,000/kW	$1,200-1,800/kW	$3,500-4,000/kW	$2,000-5,000/kWp
Fixed O&M Cost	$600-1,000/kW	$700-1100/kW	$600/kW	$1000/kW	$400/kW	$360/kW	$175/kW	$8-30/kW	$15-40/kW	$10-30/kWp
Variable O&M Cost	$0.007 - 0.02/kWh	$0.005 - 0.016/kWh	$0.004 - 0.01/kWh	$0.003/kWh	$0.002/kWh	$0.004/kWh	$0.0045-0.0056/kWh	$0.002-0.004/kWh	$0.03 0.09/kWh	$10-30/kWp
Maintenance Interval/Fuel Cell Module Durability	750 - 1,000 hrs: change oil and oil fiter 8,000 hrs: rebuild engine head 16,000 hrs: rebuild engine block	5000 - 8000 hrs	4000 - 8000 hrs	20,000 + hrs	40,000 - 80,000 hrs	40,000+ hrs	25,000 - 70,000 hrs	2 yr interval, 10 yr life	2 hr interval, 10 year life	8,000 hrs (annual maintenance for central inverters)

Figure 4-15. DER Technology Characteristics

Pairing DER technologies and economic characteristics with application needs provides an indicator of how different DERs might be suited for different applications. Figure 4-16 provides a high-level overview of application feasibility. Actual installations will depend on the specific technologies being used, the specifics of the application for which a DER is being used and other non-DER-related factors such as available incentives or relevant policies.

Application	Combustion Engines & CHP	Fuel Cell	Storage: Power	Storage: Energy	PV
Base Load	Medium	High	Low	Low	Low
UPS	Medium	Low	High	Medium	Low
Back up	High	Medium	Low	High	Low
Back up w/ Islanding	Low	Low	Low	Low	Low
Renewable Integration	Medium	Low	Medium	High	High
Peak Shaving	High	Medium	Medium	High	Medium
Demand Response	High	Medium	Medium	High	Low
Regulation	High	Low	High	Medium	Low
Reserves	Medium	Low	Low	High	Low
Supply Capacity	Medium	Medium	Medium	Low	High
T&D Deferral	Medium	Low	Low	Low	Medium

Figure 4-16. Application Feasibility

4.2 Market Penetration

DER adoption is occurring throughout the country. Some technologies experience greater penetration due to physical or indirect market conditions creating more potential (e.g., opportune thermal applications for CHP or significant solar potential). Other regions and technologies are prompted by favorable policy conditions, such as lowering barriers to entry or explicitly encouraging adoption through incentives. In terms of cumulative adoption of CHP, PV and energy storage units of two megawatts (MW) or less, California, New Jersey and Arizona lead the nation. Figure 4-17 illustrates market penetration estimates for the ten states with the greatest penetration. Large amounts of PV in these states drive the high overall DER penetration, with PV constituting over 80 to 90% of the total installed DER capacity for units under two MW.

DER adoption is occurring at different rates throughout the United States, determined in part by technical potential and by local and state market and policy conditions.

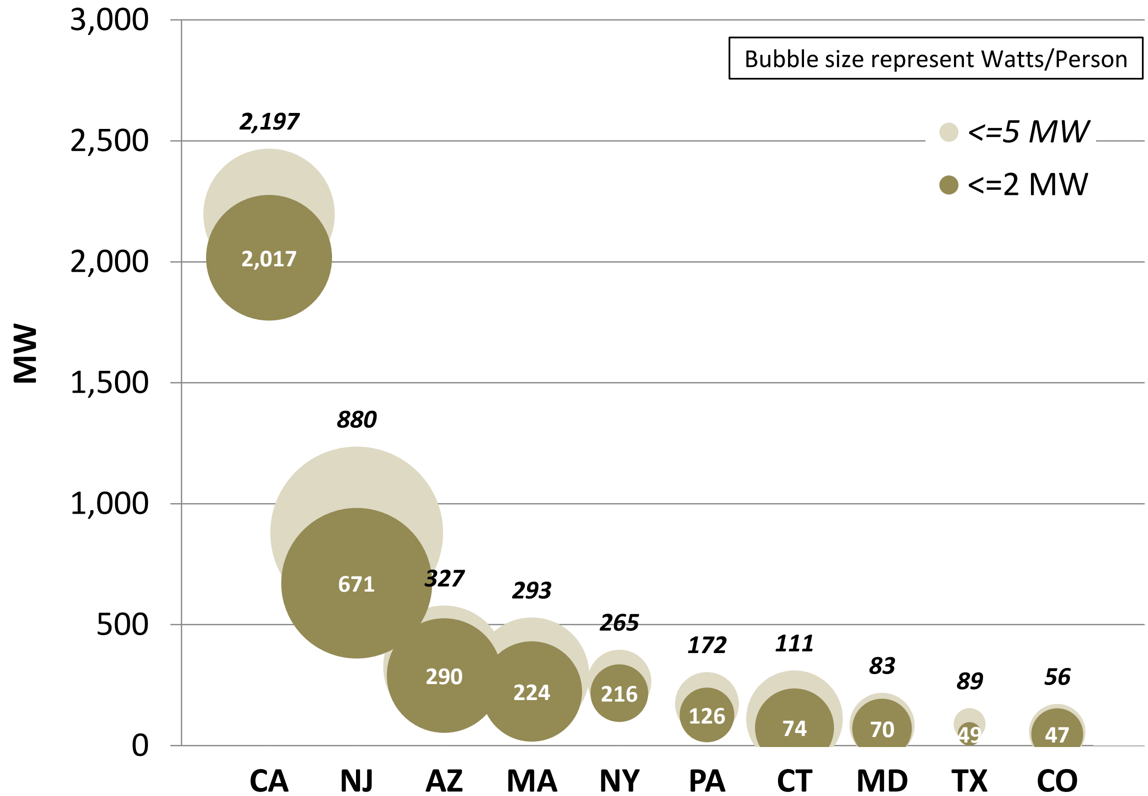

Figure 4-17. DER Adoption by State

Source: Derived from U.S. Census data, NREL Open PV Project, DOE Global Energy Storage Database, DOE and ORNL Combined Heat and Power Installation Database

New York ranks within the top five states, but is the exception in terms of the DER technology driving total penetration. Fifty seven percent of New York's DER capacity is derived from CHP.[87] Figure 4-18 illustrates the percentage share of DER installation by type in New York.

87 By some estimates of installed PV capacity, New York has roughly 100 more MW of PV than is reflected in the NREL Open PV Project database at the time these numbers were derived. The size of the installed capacity, however, was unknown, making it difficult to adjust estimates for total capacity under 2 MW. Nevertheless, it is feasible that the installed capacity of PV and CHP under 2 MW are now roughly equivalent and that the total installed capacity in New York of DER under 2 MW is now greater than 216 MW.

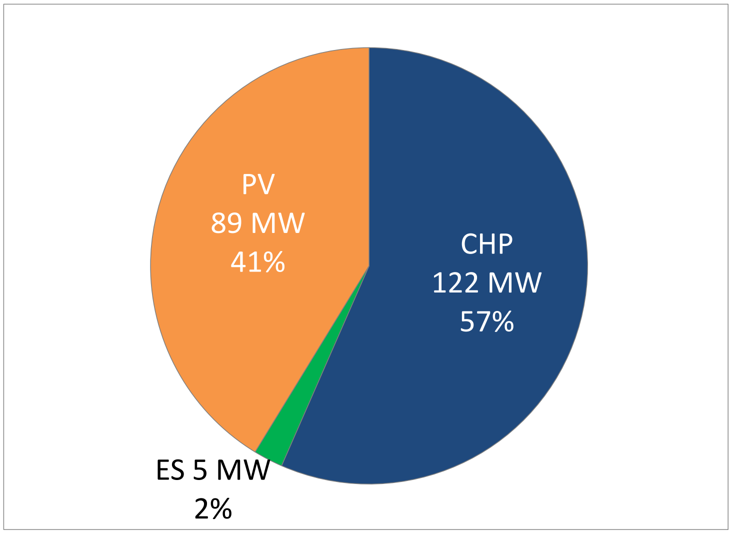

Figure 4-18. New York Share by DER Type

Figure 4-19 highlights states with the top ten installed capacity of units 2 MW or under per type of DER.

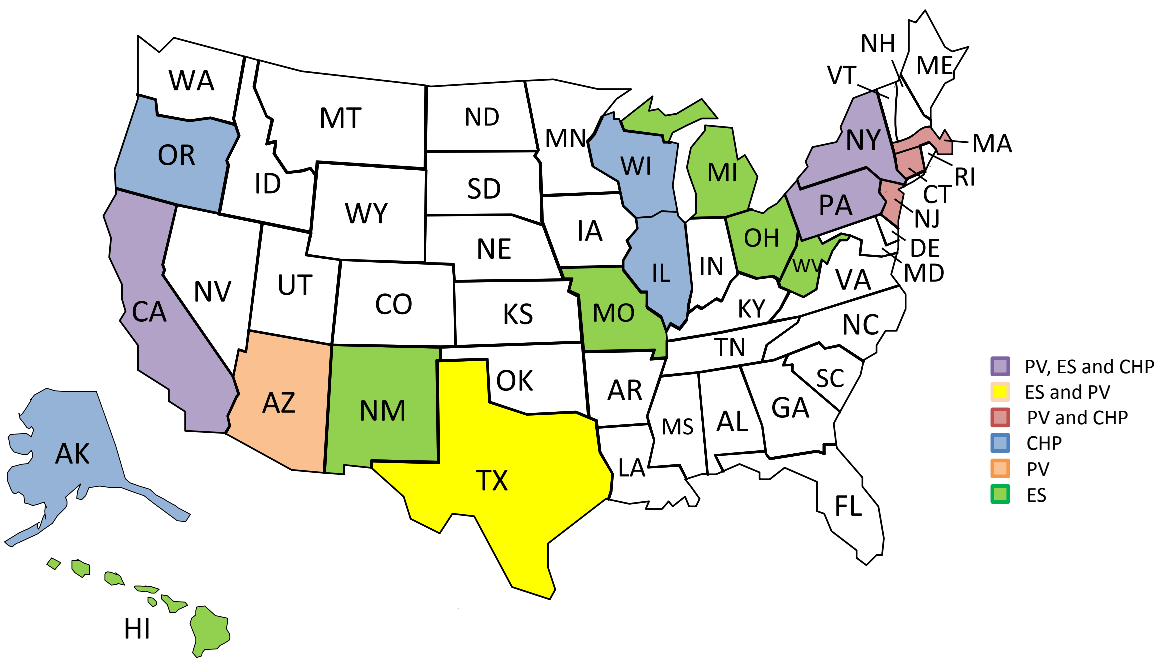

Figure 4-19. States with Top 10 Ranking in DER Adoption by Type

California, New York and Pennsylvania lead across states with the top PV, energy storage and CHP capacities under two megawatts.[88] The following subsections provide additional detail about DER installations across the U.S. and New York, by technology.

[88] While Figure 4-17notes total capacity, Figure 4-19 notes states which lead in each category of DER.

4.2.1 Solar

According to NREL's Open PV database, California, New Jersey and Arizona lead the nation in total installed capacity of PV. Together, these states account for over 3,800 MW of installed PV, over 67% of total PV installed in the United States. Currently, these states also represent the top-three states with of installations of two MW or less. Figure 4-20 illustrates total capacity (in MW_{dc}) and total capacity per person of installations of two MW or less by state for the top ten states. Bubble size normalizes across population and represents estimates of capacity per capita. Labels indicate capacity in MW_{dc}.

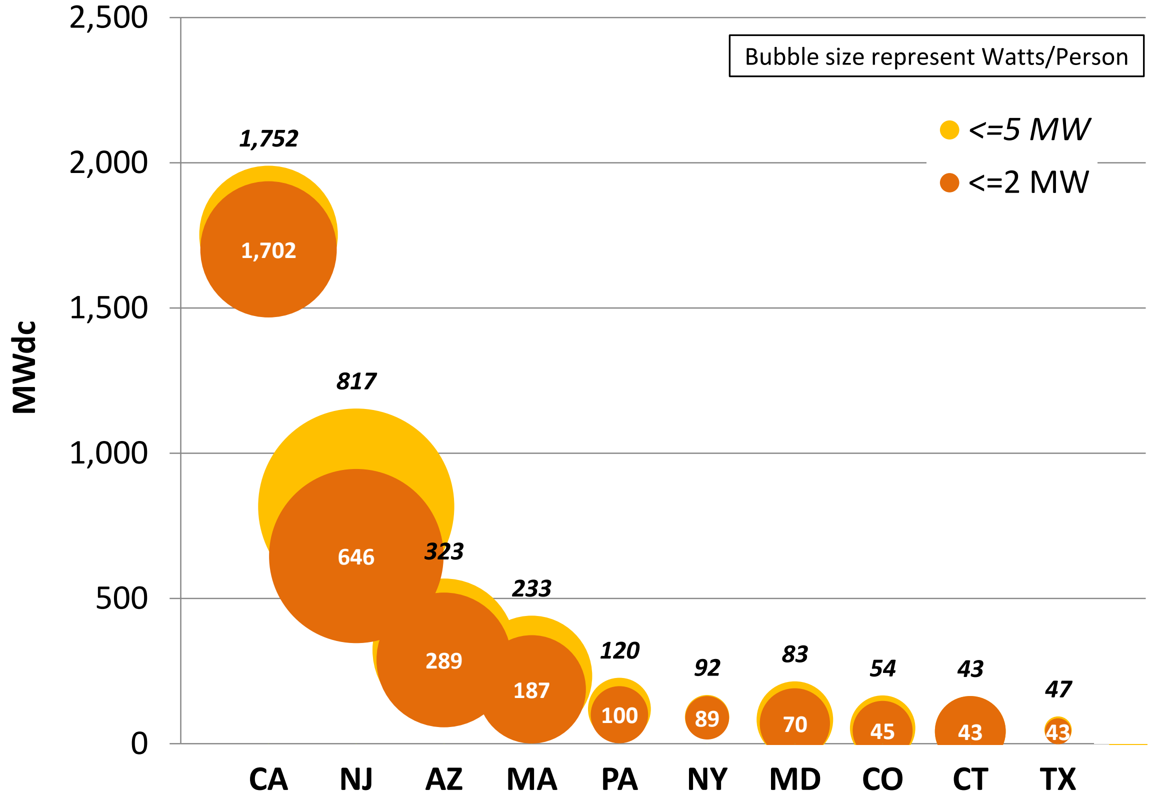

Figure 4-20. Market Penetration of Photovoltaic Solar by State[89]

Source: Derived from U.S. Census and NREL Open PV Project

New York currently has 89 MW of PV sourced from installations under two MW, with the average size being 13 kW. New York's PV capacity increases to 92 MW for all installations under five MW.

4.2.2 Energy Storage

According to the Department of Energy's Global Energy Storage Database, cumulative storage capacity for storage equal to or less than two MW is currently greatest in California, Hawaii and New York, as shown in Figure 4-21.[90] Total domestic capacity of units less than two MW is equal to 77 MW. Overall storage

[89] By some estimates of installed PV capacity, New York has roughly 100 more MW of PV than is reflected in the NREL Open PV Project database at the time these numbers were derived. The size of the installed capacity, however, was unknown, making it difficult to adjust estimates for total capacity under 2 MW. Nevertheless, it is likely that the total installed capacity in New York of PV under 2 MW is now greater than 89 MW.

[90] http://www.energystorageexchange.org/

installations total over 24,800 MW, with the majority being pumped hydropower. The majority of capacity in California is battery storage. New York has the third most installed storage of two MW or less. The total installed capacity of energy storage in New York is 1,443 MW, the majority of which is non-distributed storage. Of that amount, 4.7 MW is two MW or less with a median size is 100 kW. One hundred percent of small scale storage, projects of two MW or less, is battery storage. The majority of projects are under 200 kW, and are targeted for energy bill management.

When comparing the smaller-scale storage capacity normalized by state populations, most states have storage of 0 to 0.5 watts per person. Hawaii, West Virginia and New Mexico have the largest capacity per person, with Hawaii far outpacing others, at 5.8 watts per person.

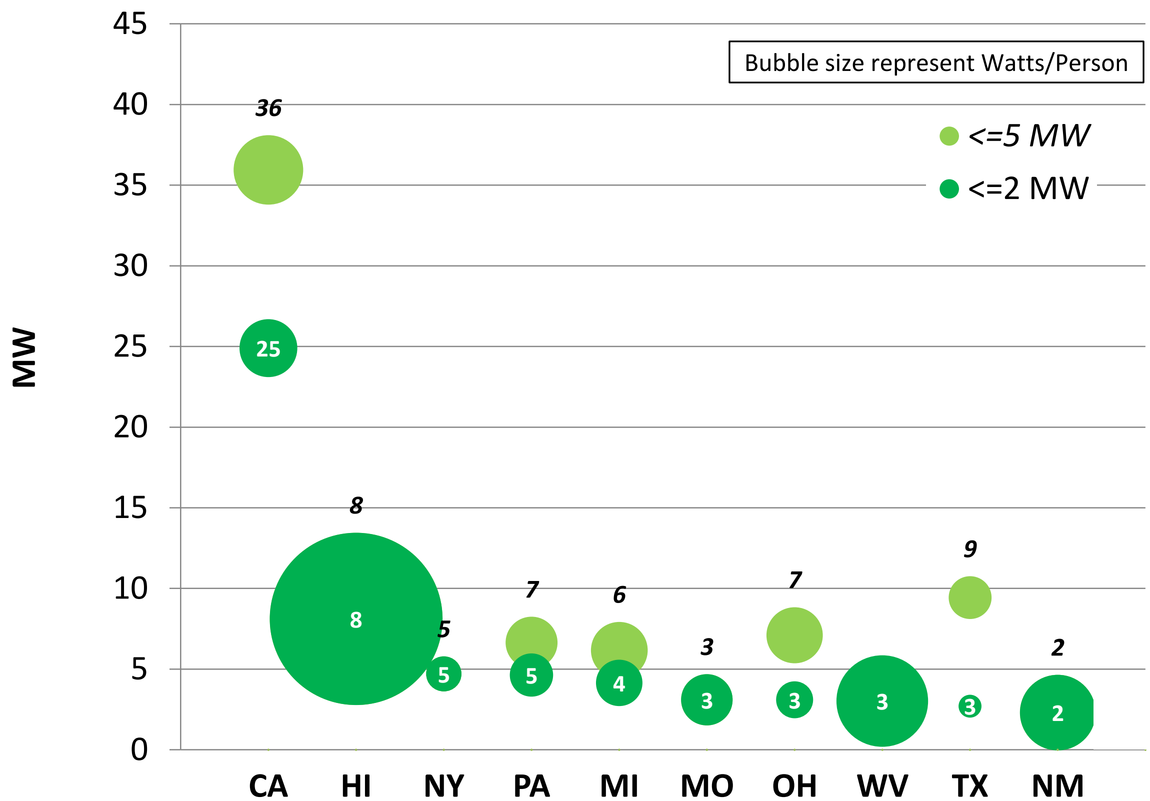

Figure 4-21. Market Penetration of Energy Storage by State

Source: Derived from U.S. Census data and the DOE Global Energy Storage Database

4.2.3 Combined Heat and Power

According to ORNL's CHP Installation Database, California and New York lead the nation in total installed CHP capacity for units under two MW. New York has roughly 122 MW of installed capacity of units two MW or under, with natural gas reciprocating engines constituting the majority. The average per person capacity for units two MW or under in New York is 6.2 watts/person, ranking the fifth highest per person in the United States. Figure 4-22 illustrates estimated installations by state.

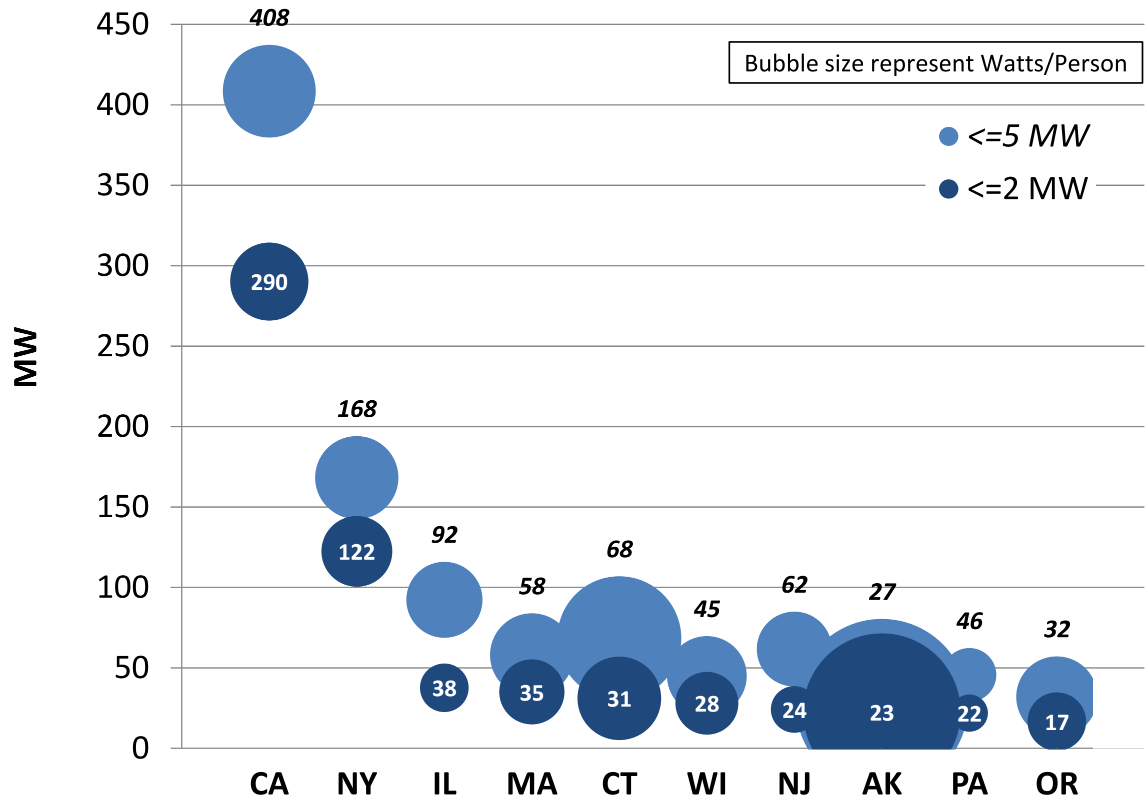

Figure 4-22. Market Penetration of Combined Heat and Power by State

Source: Derived from U.S. Census data and the DOE and ORNL Combined Heat and Power Installation Database

4.2.4 Microgrids

Current operational capacity of microgrids in the United States is estimated to be around one gigawatt (GW), with future installations planned.[91] The size of operational installations range from less than 1 MW to over 50 MW. The majority, however, are smaller scale installations. Figure 4-23 illustrates the estimated capacities by size ranges.

[91] GTM Research 2014. Of the 116 microgrid projects identified by GTM Research, 81 are currently operational and 35 are under development.

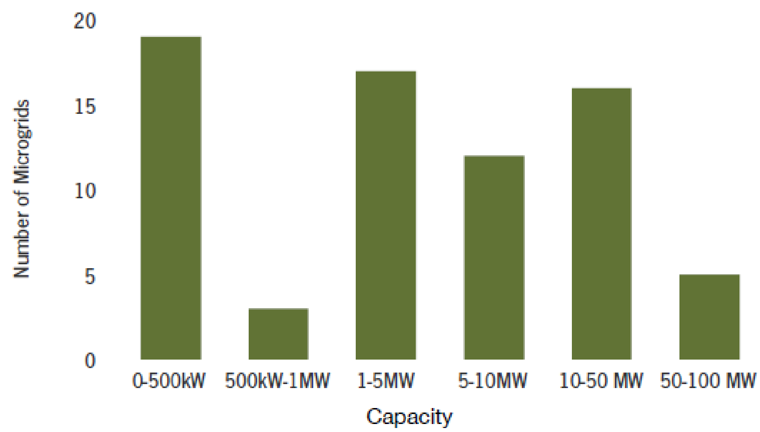

Figure 4-23. Operational Microgrid Capacity by Size Range

Source: GTM Research 2014

California, Hawaii and the Northeast represent the most active regions in the U.S. for current and planned microgrids.[92] Figure 4-24 illustrates operational and planned projects across the U.S.

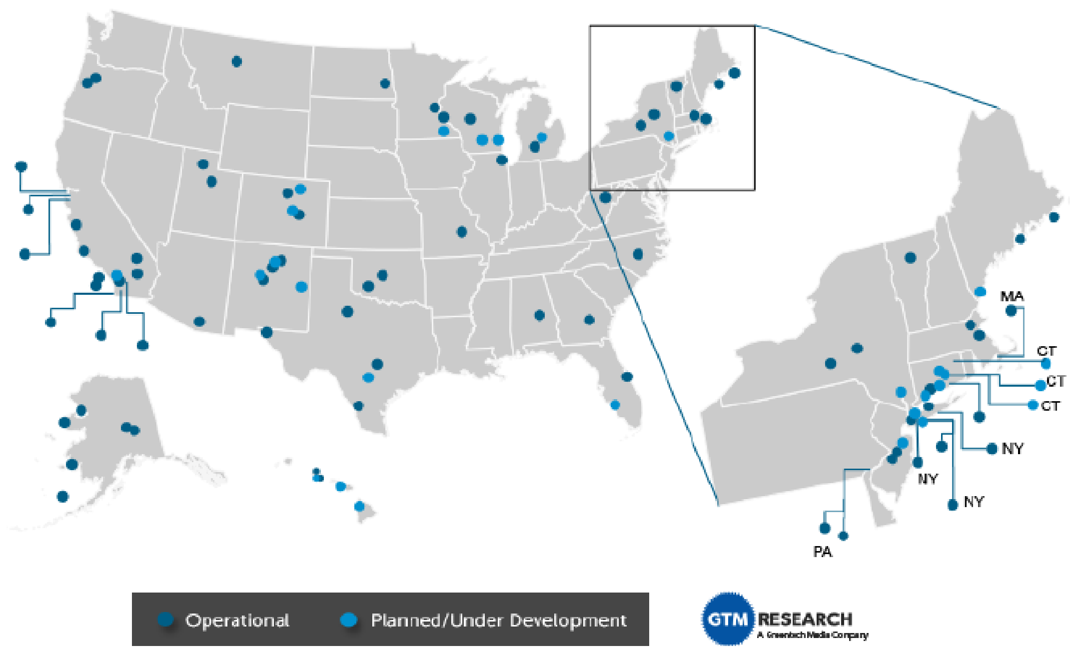

Figure 4-24. Microgrid Locations

Source: GTM Research 2014

The majority of current installations are military, research, and university sites. However, the share of public or community installations is expected to grow as additional planned projects come on-line.[93] In addition,

92 GTM Research 2014
93 Ibid.

while CHP and wind constitute the majority of the capacity for operational microgrid installations, the share of PV capacity is expected to grow.[94]

Additional information about microgrids in New York is expected to be available soon. The PSC, NYSERDA, and the Department of Homeland Security and Emergency Services are currently conducting a feasibility study of microgrids in New York to assist with disaster response.[95] The New York State Smart Grid Consortium has also recently initiated work to inventory microgrids in the State of New York.[96]

4.3 Technical Potential

The technical potential for DERs across the country is large, but it will be constrained by localized policy, technology characteristics, and retail utility offerings. New York itself has relatively high technical potential for DERs. The following subsections outline estimates of the technical potential for several DER types.[97]

4.3.1 Photovoltaic Solar

NREL estimated the total annual technical potential for rooftop PV across the country in 2012. The approach used estimates of rooftop space and solar availability to generate estimates of PV capacity and production by state.[98] Overall, NREL estimated a technical potential of 664 GW capacity and 819 TWh production of PV. California has the highest technical potential of 76 GW (106 TWh) due to its mix of high population and relatively good solar availability. New York ranks seventh and is estimated to have 25 GW of capacity with a production capability of 28,780 GWh. This relatively high ranking is likely due to higher potential for rooftop space. Figure 4-25 depicts a map of production potential by state for rooftop PV in the United States.

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[94] Ibid.

[95] See A.7049/Crespo; Chapter 221 of 2013

[96] See http://nyssmartgrid.com/wp-content/uploads/NYSSGC-RFP-Microgrid-Project-Inventory-1-6-14.pdf for more information.

[97] Technical potential differs from economic potential in that it does not account for factors affecting DER adoption. Rather, it outlines the potential from a technology-only standpoint.

[98] Rooftop PV technical potential is estimated by the methodology proposed by Denholm and Margolis (Denholm, P.; Margolis, R. (2008b). "Supply Curves for Rooftop Solar PV-Generated Electricity for the United States." NREL/TP-6A0-44073. Golden, CO: National Renewable Energy Laboratory). First, the floor space for commercial and residential buildings are estimated, and then scaled up to obtain a building footprint based on the number of floors. The Energy Information Admiration's 2005 Residential Energy Consumption Survey (DOE EIA 2005) and 2003 Commercial Building Energy Consumption Survey (DOE EIA 2003) are used to calculate the average floor estimates. Roof footprint is calculated by dividing the building footprint by the number of floors. Based on these estimates, 8% of residential and 63% of commercial rooftops are flat. For pitched roofs, the orientations are assumed to be distributed uniformly. An availability factor is used to account for shading, rooftop obstructions and constraints to derive the usable roof area. Residential availability factors range from 27% to 22% in warm/arid and cool climates, respectively, and 60% to 65% for commercial spaces. Estimated average module efficiency is set at 13.5% with a power density for flat roofs of 110 W/m2 and 135 W/m2 for the rest. Finally, state PV capacity is aggregated to match Census Block Group populations."

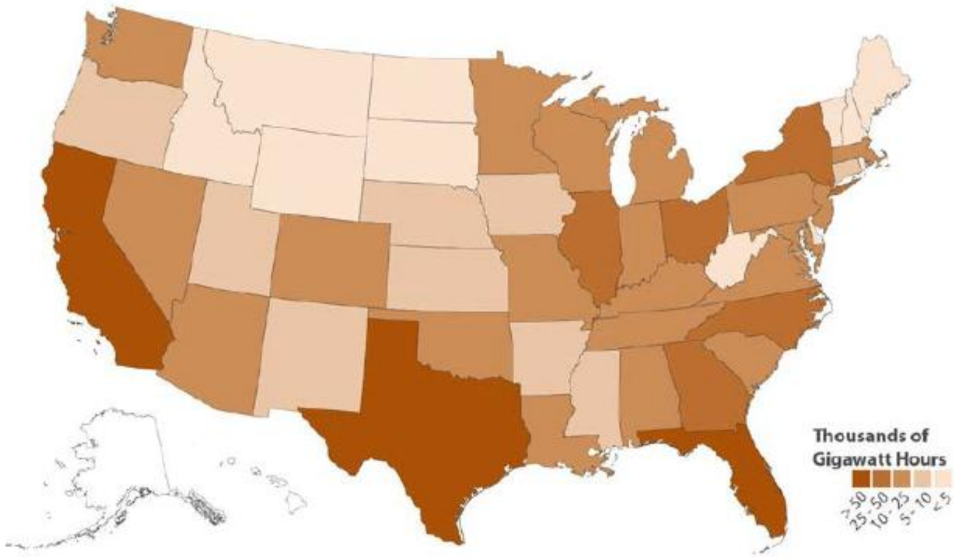

Figure 4-25. Map of Estimated Rooftop PV Potential in the U.S. by State

Source: NREL 2012

Figure 4-26 summarizes the technical potential across different states, noting GWh and GW potentials.

State	GW	GWh	State	GW	GWh
Alabama	13	15,476	Montana	2	2,194
Alaska	1	NA	Nebraska	4	5,337
Arizona	15	22,736	Nevada	7	10,767
Arkansas	7	8,485	New Hampshire	2	2,299
California	76	106,411	New Jersey	14	15,768
Colorado	12	16,162	New Mexico	4	6,513
Connecticut	6	6,616	New York	25	28,780
Delaware	2	2,185	North Carolina	23	28,420
District of Columbia	2	2,490	North Dakota	2	1,917
Florida	49	63,987	Ohio	27	30,064
Georgia	25	31,116	Oklahoma	9	12,443
Hawaii	3	NA	Oregon	8	8,323
Idaho	3	4,051	Pennsylvania	20	22,215
Illinois	26	30,086	Rhode Island	2	1,711
Indiana	15	17,151	South Carolina	12	14,413
Iowa	7	8,646	South Dakota	2	2,083
Kansas	7	8,962	Tennessee	16	19,685
Kentucky	11	12,312	Texas	60	78,717
Louisiana	12	14,368	Utah	5	7,514
Maine	2	2,443	Vermont	1	1,115
Maryland	13	14,850	Virginia	19	22,267
Massachusetts	10	11,723	Washington	13	13,599
Michigan	22	23,528	West Virginia	4	4,220
Minnesota	12	14,322	Wisconsin	12	13,939
Mississippi	7	8,614	Wyoming	1	1,551
Missouri	13	16,160	U.S. Total	664	818,733

Figure 4-26. U.S. Estimated Technical Potential for Rooftop PV

Source: NREL, 2012

A recent report by NYSERDA estimates a sizeable technical and economic opportunity for PV. For residential PV, NYSERDA estimates a total technical potential of 881 MW cumulative peak capacity and 2,836 GWh production by 2020 and 2,615 MW cumulative peak capacity and 8,223 GWh production by 2030. For commercial PV, NYSERDA estimates a total technical potential of 1,174 MW of cumulative peak capacity and 3,706 GWh of production by 2020 and 3,487 MW of cumulative peak capacity and 10,745 GWh of production by 2030.[99]

4.3.2 Energy Storage

Industry projections for the U.S. storage market are that it will continue to grow fairly rapidly. A 2014 estimate by Azure International estimates the technical potential for storage in the United States at over 300 GW, including both distributed and bulk storage.[100] The forecasted cumulative capacity of economic installations was projected to reach just under 2,000 MW by 2020 for all storage, and about 750 MW for smaller-scale applications.[101] Estimates by GTM Research suggest that over 720 MW of distributed storage may be deployed between 2014 and 2020, representing a cumulative annual growth rate of roughly 34 percent.[102] Figure 4-27 illustrates GTM 2014 estimates of cumulative installed commercial storage capacity over time.

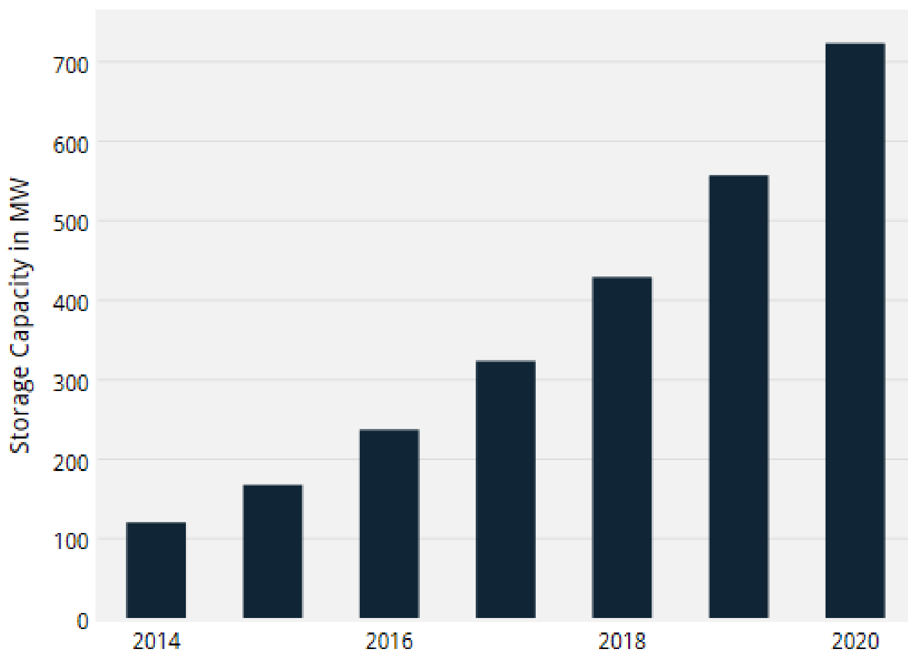

Figure 4-27. Cumulative Installed Commercial Storage Capacity

Source: GTM Research 2014[103]

There are a limited number of projections of New York's Energy storage potential. However, a 2013 study by Navigant estimated 75 MW of demand side storage capacity by 2020 and 201 MW by 2030.[104]

[99] NYSERDA 2014

[100] Azure International 2014

[101] Ibid.

[102] GTM Research 2014, For more information, see: http://www.greentechmedia.com/articles/read/Commercial-Energy-Storage-Market-to-Surpass-720-MW-by-2020

[103] http://www.greentechmedia.com/articles/read/Commercial-Energy-Storage-Market-to-Surpass-720-MW-by-2020

4.3.3 Combined Heat and Power

A 2002 study by NYSERDA estimated a total technical potential of 8,477 MW for all new CHP from 2002 onwards. The same study estimated an incremental technical potential for units 5 MW or less at 6,259 MW. According to the ORNL CHP Installation Database, roughly 107 MW of CHP less than 100 MW was installed between 2002 and 2013. Figure 4-28 outlines the estimates by sector and size range.

Size Range	Industrial		Commercial		Total	
	Sites	MW	Sites	MW	Sites	MW
State Total						
50 to 500 kW	3,894	300	16,048	1,240	19,942	1,540
500 kW to 1 MW	428	195	3,867	1,584	4,295	1,778
1 MW to 5 MW	434	685	1,280	2,256	1,714	2,940
5 MW to 20 MW	63	488	149	1,240	212	1,728
> 20 MW	9	280	7	210	16	490
Total	4,828	1,948	21,351	6,529	26,179	8,477

Figure 4-28. Estimated Incremental CHP Technical Potential in 2002

Source: NYSERDA 2002[105]

The existing capacity of CHP in 2000 was estimated at about 5,070 MW, with roughly 40% at sizes smaller than 100 MW. The total cumulative technical potential for sites smaller than 100 MW, including existing CHP, is therefore roughly 8,300 MW.

More recently, NYSERDA published a study of the technical and economic potential of renewable resources in New York. Estimates for the technical potential of biothermal-based commercial CHP (of around 2 MW) range from 144 MW in 2020 to 324 MW in 2030.[106]

Overall, New York is estimated to have a large technical potential for smaller-scale CHP.

4.3.4 Microgrids

Estimates of technical and economic potential of microdgrids in the UnitedStates vary quite dramatically, in large part because the performance and price of associated technologies and the surrounding policies for microgrids are rapidly evolving at present. Under a scenario of slow and steady economic growth and cost reductions in PV, Navigant estimated that total microgrid capacity in North America would be 2,022 MW by 2017.[107] The predominant segments within this estimate are campus or institutional applications (at 1,572 MW) and stationary military bases (at 450 MW).

[104] Navigant 2013. Available online at: https://eispctools.anl.gov/document/19/file

[105] Available online at: https://www.nyserda.ny.gov/-/media/Files/EIBD/Industrial/chp-market-potential.pdf

[106] NYSERDA 2014

[107] Navigant (Pike Research), Distributed Energy Systems for Campus, Military, Remote, Community, and Commercial & Industrial Power Applications: Market Analysis and Forecasts, 1Q 2012

4.4 Environmental Requirements

Environmental benefits are cited as one motivating factor behind the adoption of DER.[108] However, the environmental profile of DERs can vary greatly across different technologies. Furthermore, the environmental policies to which DERs are subject can vary significantly. The performance characteristics and the policies which shape performance requirements strongly influence the comparability of DERs across DER technologies and to centralized generation assets. Furthermore, several federal, state and local policies shape the environmental performance of competing centralized generation assets as well. This section outlines the federal, state and local environmental requirements relevant to DER technologies, notes how such regulations potentially affect DER operation, and compares and contrasts the emissions profile of DERs with centralized assets.

> ***The performance characteristics and the policies which shape performance requirements for DERs and centralized generation strongly influence the comparability of DERs across DER technologies and to centralized generation.***

Broadly, environmental regulations stem from federal, state, and local policies. At the federal level, the U.S. Environmental Protection Agency (EPA) sets standards that regulate national air quality. In turn, these standards can result in emissions limitations on stationary sources which are promulgated by state and local authorities.

The Clean Air Act, last amended in 1990, requires the EPA to set National Ambient Air Quality Standards (NAAQS) for wide-spread pollutants that are considered harmful to public health and the environment. EPA has set NAAQS for six principal, or 'criteria', pollutants, including:

- Carbon Monoxide (CO);
- Lead (Pb);
- Nitrogen Dioxide (NO_2);
- Ozone (O_3);
- Particle Pollution (PM2.5 and PM10); and
- Sulfur Dioxide (SO_2).[109]

As part of the 1977 Clean Air Act Amendments, Congress established the New Source Review (NSR) permitting program. The primary goal of NSR is to ensure that air quality is not significantly degraded from the addition or remodeling of a power plant or other industrial installation. The NSR, which has undergone several revisions since its inception, largely outlines three types of permitting requirements.[110] A source may have to meet one or more of these permitting requirements:

1. Prevention of Significant Deterioration (PSD) permits which are required for new major sources or a major source making a major modification in an attainment area;

[108] As noted in Section 3, several PV cost-benefits studies estimate the benefits of avoided carbon and criteria pollutants, as well as other unspecified environmental benefits. RMI, 2013. Avoided emissions benefits from CHP are also often considered. See http://www.epa.gov/chp/basic/environmental.html for more information.

[109] For additional details regarding these standards, see: http://epa.gov/air/criteria.html

[110] The latest information is available at http://www.epa.gov/nsr/actions.html

2. Nonattainment NSR permits which are required for new major sources or major sources making a major modification in a nonattainment area; and
3. Minor source permits.

Nonattainment NSR applies to new major sources or major modifications at existing sources in areas that are not in attainment with NAAQS, and are customized for the particular nonattainment area. Minor NSR is for pollutants from stationary sources that do not require the PSD or nonattainment NSR permits. Most NSR permits are issued by state or local air pollution control agencies. EPA establishes the basic requirements for an NSR program in its federal regulations. States may develop unique NSR requirements and procedures tailored to the air quality needs of each area as long as the program is at least as stringent as the EPA's requirements. A state's NSR program is defined and codified in its State Implementation Plan (SIP).

State permitting and emissions control requirements can vary widely but are typically structured into four categories, depending on the size and use of the generator:[111]

- De Minimis Exemptions;
- State Minor Source Permitting;
- Major Source Permitting; and
- Emergency Generators.

Most states allow some kind of De Minimis exemption, meaning that generating units below a certain threshold for capacity or total annual emissions do not require a permit of any kind, though the requirements and conditions for these exemptions vary by state. Sources that are not exempted must obtain a permit, as outlined in the SIP. Trigger thresholds for the permitting categories are outlined in the federal NSR permitting process and depend on the air quality status (attainment versus nonattainment) of the area in which the unit is located. Sources that fall in between the De Minimis and the Major Source thresholds are generally subject to state minor source permitting. In addition, most states have special treatment for emergency backup generators.

New York City and surrounding metropolitan areas (NYMA) are designated as a moderate non-attainment area for ozone. In addition, counties in and around New York City are designated non-attainment areas for particulate matter ($PM_{2.5}$).[112] This means air quality regulation in these areas is more stringent than in the rest of the state, especially for NO_x and PM. In accordance with the Clean Air Act, states containing non-attainment areas are required to implement Reasonably Available Control Measures (RACM) to provide a means to attain the NAAQS for the pollutant in question. The New York State Department of Environmental Conservation (DEC), together with the Ozone Transport Commission (OTC), has developed a list of approximately 1,000 control measures relating to electrical generating units and other equipment, to help alleviate the ozone problem within the non-attainment areas across the state.[113] Measures include those for large and small units, including DG.[114] Figure 4-29 depicts the NY Nonattainment Areas for 8-hour Ozone.

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[111] Energy and Environmental Analysis, Inc.: http://www.eea-inc.com/rrdb/DGRegProject/States/Newsite/newindex.html

[112] Nitrogen oxides (NO_x) and volatile organic compounds (VOCs) react when it is hot and sunny and produce ozone. Ground-level ozone is especially prevalent in cities, due to the concentration of NO_x and VOCs and the favorable weather patterns during summer, and at high concentration is considered a health hazard.

[113] See additional information at: http://www.otcair.org/

[114] For more information, see http://www.dec.ny.gov/chemical/37107.html

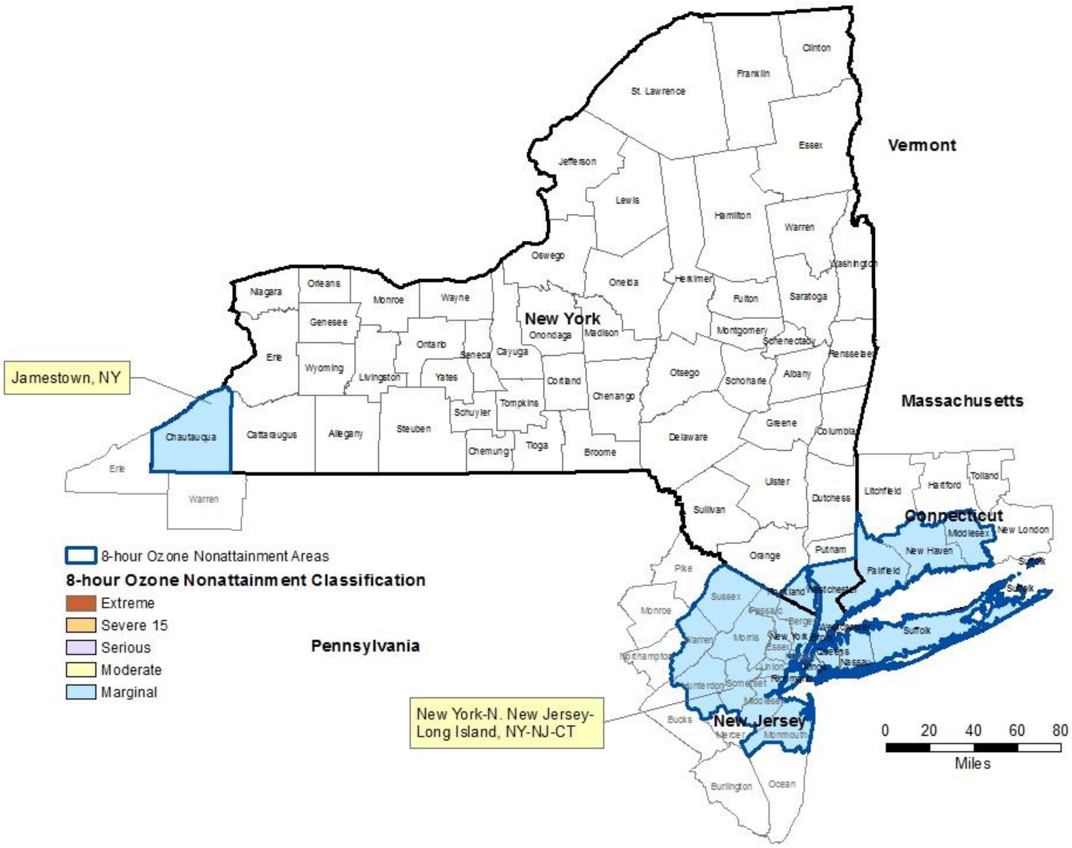


Figure 4-29. New York Nonattainment Areas for 8-hour Ozone

Source: Environmental Protection Agency, as of December 5, 2013

Hydrocarbon fuelled DERs can add to ozone pollution issues as they are typically located in urban areas and generally have shorter stacks than central station power plants, causing emissions to impact the vicinity of the source. In response to the expanding DER market, NY DEC is implementing a new rule to set emissions standards for DG, 6 NYCRR Part 222.[115] The rule is expected to be finalized in 2014. The draft rule, which was reviewed by stakeholders in June 2013, includes emission limits for economic dispatch resources (i.e. non-emergency resources) on NO_x and PM. These limits are technology and fuel specific and apply to sources emitting oxides of nitrogen less than the major source threshold (which would trigger a major source NSR) and with capacities larger than the De Minimis exemption for New York State, i.e. 200 horsepower (hp) for New York City or 400hp for the rest of New York state. Figure 4-30 lists NO_x emission limits from the draft rule 6 NYCRR Part 222.

[115] 6 NYCRR Part 222 went into effect in 2008, but is still under development. For more information, see: http://www.dec.ny.gov/chemical/37107.html

Technology	Fuel	NOx limit	Unit
Combined Cycle	NG	25 ppm	parts per million on a dry volume basis corrected to 15 percent oxygen
	Oil	42 ppm	
Simple Cycle	NG	50 ppm	
	Oil	100 ppm	
Reciprocating Engine	NG	1.5 gm/hp-hr	grams per brake horsepower-hour
	Distillate Oil	2.3 gm/hp-hr	

Figure 4-30. 2013 Draft New York NO_x Emission Limits

Source: Department of Environmental Conservation

The draft rule also includes limits on particulate matter, stating that sources subject to the rule must either 1) meet a PM emission limit of 0.10 lb/MMBtu or 2) use a diesel fuel with a sulfur content of 15 ppm or less and be equipped with a pollution control device designed to remove 85% or more of the PM from the exhaust stream.[116] Financial incentive programs can also apply specific standards, such as with the current Combined Heat and Power Performance program from NYSERDA, which applies an output-based emission standard for NO_x of no more than 1.6 lbs/MWhr.[117]

4.4.1 National Model Emission Rule for Distributed Generation

The development of DG emission regulations, which started in Texas and California, sparked concern that many individual states would develop emission standards for DG and create an overly complex, conflicting set of permitting requirements that would limit the development of DG. In 2000, the National Renewable Energy Laboratory engaged the Regulatory Assistance Project (RAP) to facilitate the development of a uniform, national model emission rule for small DG equipment.[118] The goal was to develop a model rule that could be uniformly applied throughout the United States and provide appropriate environmental protections and technology drivers for DG (such as output-based regulation). The stakeholder group involved with the process consisted primarily of state energy and environmental regulators with a few participants from the DG industry and representatives from EPA, DOE, and environmental groups. The model rule was completed in February of 2003. However, emissions regulations for distributed generation still vary widely in rigorousness, the chemicals regulated, and in formulation across (and even within) states.

4.4.2 Central Station Emissions

Over the past ten years, emissions from central generation in New York State have been steadily declining, as shown in Figure 4-31. This is due, in part, to the retirement of older generators and their replacement by newer, more efficient facilities that are also subject to more stringent environmental codes.

[116] Draft 6 NYCRR Part 222 rule discussed at June 25 2013 Stakeholder meeting

[117] For more information, visit: http://www.nyserda.ny.gov/Energy-Efficiency-and-Renewable-Programs/Commercial-and-Industrial/CI-Programs/Combined-Heat-and-Power.aspx

[118] The Regulatory Assistance Project (RAP) is a non-profit organization formed in 1992 that provides workshops and education assistance to state public utility regulators on electric utility regulation.

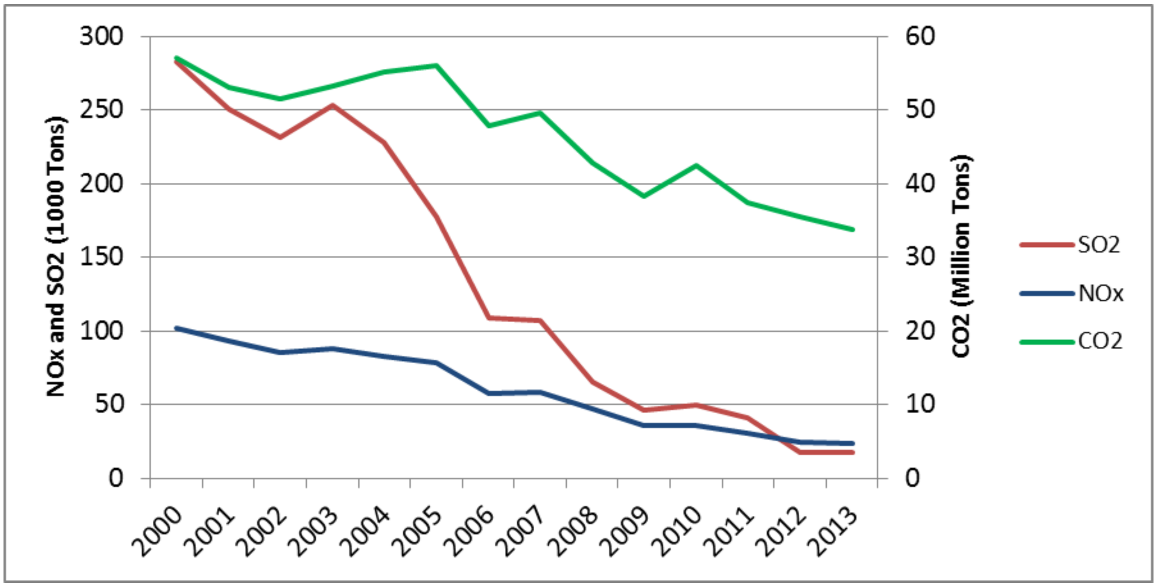


Figure 4-31: Emissions from Central Generation in New York State 2000-2013

Source: EPA Air Markets Program Data 2014

In part, the reduced emissions to date stem from environmental standards that apply to existing generation becoming more stringent as well. For example, the Best Available Retrofit Technology (BART) applies to eligible older sources (installed or modified prior to 1977) requiring a case-by-case assessment of feasible and effective retrofitting technologies for controlling air pollution.[119] As noted earlier, states are required to submit a SIP that complies with RACM requirements for nonattainment areas, proving that reasonable and effective measures have been taken in order to achieve attainment as quickly as possible. The RACM includes RACT (Reasonably Available Control Technology), which the EPA has defined as "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility."[120] Limits and requirements for RACT are continuously updated, with the latest revision going into effect July 1, 2014 being significantly more stringent than current regulation, as shown in Figure 4-32.[121]

[119] Part 249: Best Available Retrofit Technology (BART), Viewed May 2014. Available online at: http://www.dec.ny.gov/regs/64659.html

[120] EPA, 44 FR 53762; September 17, 1979, Also http://www.epa.gov/apti/video/sip2009/JohnSilvasi.pdf

[121] Subpart 227-2 Reasonably Available Control Technology (RACT) For Major Facilities of Oxides Of Nitrogen (NOx) (Filed 1/12/04. Amended adoption filed 6/8/10) Available online at: http://www.dec.ny.gov/regs/4217.html

Existing NOx RACT Limits #/mmBTU				
	Boiler Type			
Fuel Type	**Tangential**	**Wall**	**Cyclone**	**Stoker**
Gas Only	0.20	0.20		
Gas/Oil	0.25	0.25	0.43	
Coal Wet	1.00	1.00	0.60	
Coal Dry	0.42	0.45		0.30
New NOx RACT Limits #/mmBTU				
	Boiler Type			
Fuel Type	**Tangential**	**Wall**	**Cyclone**	**Fluidized Bed**
Gas Only	0.08	0.08		
Gas/Oil	0.15	0.15	0.20	
Coal Wet	0.12	0.12	0.20	
Coal Dry	0.12	0.12		0.08

Figure 4-32: Current and future RACT limits for NOx

Source: Department of Environmental Conservation[122]

In addition, fuel composition, such as those listed in Figure 4-33 use is regulated to limit pollutants such as sulfur.[123] Overall, many pollutants are regulated across various channels, contributing to the emissions decline to date, but also promising a continuing decline of emission rates from central generation in the future.

[122] Subpart 227-2 Reasonably Available Control Technology (RACT) For Major Facilities of Oxides Of Nitrogen (NOx). Viewed May 2014. Available online at: http://www.dec.ny.gov/regs/4217.html

[123] Subpart 225-1 Fuel Composition and Use - Sulfur Limitations, Viewed May 2014. Available online at: http://www.dec.ny.gov/regs/4225.html; Subpart 225-4 Motor Vehicle Diesel Fuel, Viewed May 2014, Available online at: http://www.dec.ny.gov/regs/4222.html

Area	Liquid fuel (% sulfur by weight)		Solid fuel (pounds of sulfur per million Btu gross heat content)
	Residual	Distillate*	
New York City	0.3	0.2	0.2 MAX
Nassau, Rockland and Westchester Counties	0.37	0.37	0.2 MAX
Suffolk County: Towns of Babylon, Brookhaven, Huntington, Islip, and Smith Town	1	1	0.6 MAX
Erie County: City of Lackawana and South Buffalo	1.1	1.1	1.7 MAX and 1.4 AVG
Niagara County and remainder of Erie County	1.5	1.5	1.7 MAX and 1.4 AVG
Remainder of State	1.5	1.5	2.5 MAX, 1.9 AVG, & 1.7 AVG (ANNUAL)

Figure 4-33. Fuel Sulfur Limits in New York State

Source: Department of Environmental Conservation[124]

4.4.3 Emissions Comparison

DERs have the potential environmental benefit of increased efficiency, due in part to avoided transmission and distribution losses. For example, power generation near the place of consumption minimizes electricity transmission losses and by extension the total energy produced to meet demand. In addition, some DERs, such as CHP or fuel cells, can increase overall energy efficiency by cogenerating power while meeting heating and cooling needs, while others, such as PV or energy storage, produce no emissions. (Emissions may be associated with energy storage, depending on the charging/discharging efficiency and the source used to charge). However, the net air quality effects are highly dependent on the central generation mix of the region, the time of day, the location of the central power plant as well as the distributed technology and usage, emissions limits, and control measures enforced. Furthermore, the exposure to pollutants is not strictly related to total pollutant emissions but rather is affected by the spatial and temporal distribution of emissions and resulting atmospheric chemistry and transport.[125] Of particular concern is high ground-level concentrations of pollutants near population centers.[126]

The simple comparison conducted here does not account for such factors. Rather, the high-level comparison illustrates the role of emissions limitations. Therefore, it does not consider locational aspects, such as pollution transport, or operational aspects such as ramping and time of day, and simply reflects a snapshot in time.

For a comparison that highlights historical emissions profiles of DER and centralized generation, data was compiled from the EPA Air Markets Program Data, a comprehensive database on the emissions and environmental characteristics of almost all electric power generated in the United States, and the CHP

[124] Subpart 225-1 Fuel Composition and Use - Sulfur Limitations. Viewed May 2014, Available online at: http://www.dec.ny.gov/regs/4225.html
[125] Carreras et. al, University of California, 2010 "Central power generation versus distributed generation - An air quality assessment in the South Coast Air Basin of California"
[126] Ibid.

Emissions Calculator, updated August 29, 2012, a tool available from the EPA.[127] Emissions from a one MW CHP system using natural gas are contrasted with the average emissions profile in New York State. The CHP technology assumptions are listed in Figure 4-34. It is assumed that this unit provides heating only, no cooling. If cooling is included, additional efficiencies could be expected.

CHP Technology:	**Reciprocating Engine - Lean Burn**	
Fuel:	Natural Gas	
Total CHP Capacity:	1,000	kW
Operation:	5,840	hours per year
Heat Rate:	9,763	Btu/kWh HHV
Total Fuel Consumption:	57,015	MMBtu/year
Total CHP Generation:	5,840	MWh/year
CHP Thermal Output (heating):	25,223	MMBtu/year Total

Figure 4-34. CHP Technology Assumptions

Source: EPA CHP Partnership CHP Emissions Calculator

Figure 4-35 depicts the emissions reduction from this CHP unit when it is displacing central generation with the average emission profile for New York State in 2013. This reduction takes into account the benefit from avoiding transmission losses, by applying a regional average for losses, as well as the thermal generation (and corresponding emissions) displaced by the CHP unit. In this example, when the CHP unit is displacing central generation in New York, it results in a net reduction of many pollutants, including SO_2, CO_2 and other greenhouse gases, as well as over-all fuel consumption. In this case, no emissions control for NO_x is assumed and the total NO_x from the distributed CHP is higher than for central generation.

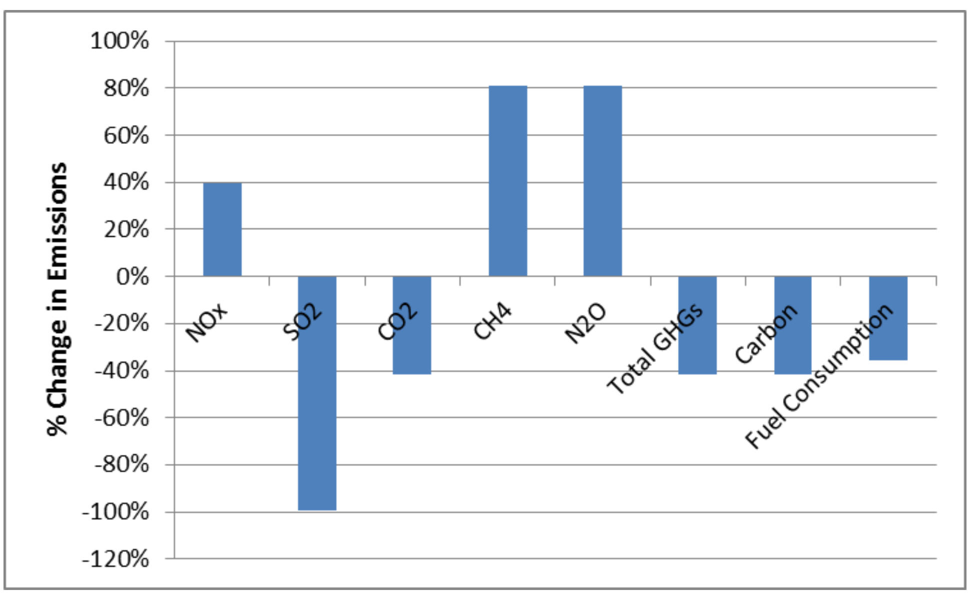


Figure 4-35. Example of CHP Displacing Central Generation in NY State: % Change in Emissions, no NO_x control

[127] EPA AMPD http://ampd.epa.gov/ampd/; The CHP Emissions Calculator, developed for EPA's CHP Partnership by Energy and Environmental Analysis, Inc. and ORNL, was used for this purpose.

Source: CHP Emissions Calculator, EPA AMPD 2013 data

However, it is possible to limit NO_x using one of several control technologies. Two post-combustion technologies that may be applied to natural gas-fired boilers to reduce NO_x emissions are selective noncatalytic reduction (SNCR) and selective catalytic reduction. According to the EPA, a 24% reduction can be applied to the appropriate NO_x emission factor for large and small wall fired boilers with SNCR control.[128] This equates to a NO_x emission rate of 0.170 lb NO_x/MMBtu for the CHP unit. Stringent emissions standards, such as the NO_x limit in effect in eastern Texas which requires an output-based limit of 0.14 lb NO_x/MWh, may also be effective in forcing distributed generation to reduce emissions, increase efficiency and perform on par with central generation. Figure 4-36 depicts the effects of applying SNCR control or a NO_x limit of 0.14 lb NO_x/MWh on the NO_x emissions from the above unit, compared with the average emissions profile of central generation in New York State.

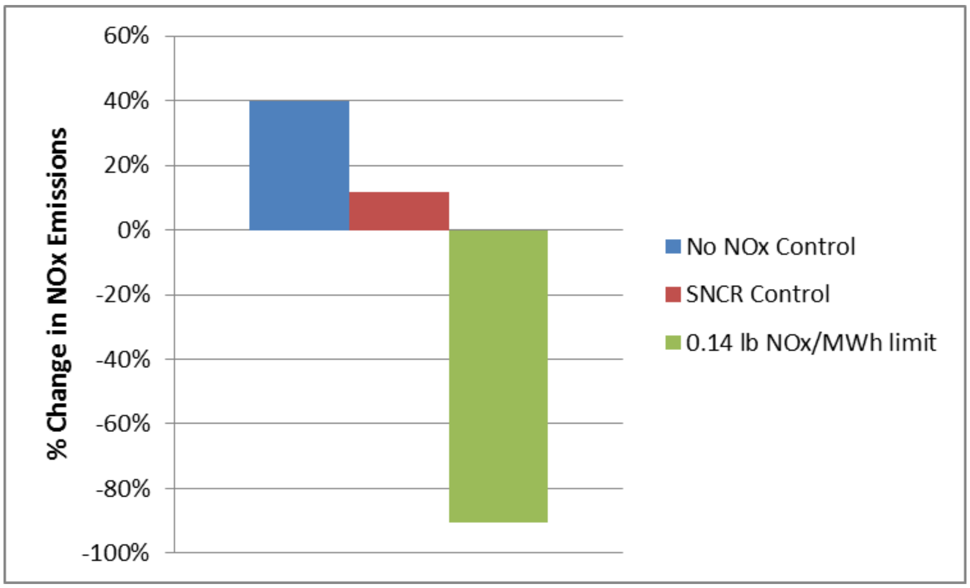


Figure 4-36: Example of CHP Displacing Central Generation in NY State: NO_x Emissions

Source: Derived from CHP Emissions Calculator and EPA AMPD 2013 data

To consider the potential for future emissions policies in changing the comparison between DER and centralized generation, we compare a new, efficient natural gas fired combined cycle unit and the above CHP unit as shown in Figure 4-37. This type of unit is likely more representative of a future central generation asset. On a strict lb/MWh basis, the CHP unit cannot compete with this modern central generation source. It is worth noting that the CHP unit is also displacing thermal production. The environmental footprint of the original device producing thermal output will depend on whether it is gas or oil-fired, its usage, design and age.

[128] http://www.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf

	Displaced Electricity	CHP: Recip Engine - Lean Burn, NG		
Emission Rates	Gas combined-cycle 3 ppm	No NOx Control	SNCR Control	0.14 lb/MWh regulated NOx limit
NOx (lb/MWh)	0.08	2.07	1.66	0.14
SO2 (lb/MWh)	0.00	0.01	0.01	0.01
CO2 (lb/MWh)	818	1,141	1,141	1,141

Figure 4-37: Example of Comparison between CHP and Natural Gas Combined Cycle Emission Rates

Source: Derived with the CHP Emissions Calculator

Overall, central generation, especially with current and future technology and regulations, can be more efficient and can generally emit fewer pollutants per megawatt-hour produced, while distributed generation can help avoid transmission losses and can address local thermal needs, thus reducing overall fuel consumption and affecting emissions dispersion. Policies regulating the emission profiles of centralized generation and DERs will have a significant impact on the net effect of DERs displacing centralized generation.

5 RETAIL RATES, REGULATIONS, AND INCENTIVES FOR DER

5.1 The Role of Rates, Regulations, and Incentives on Customer Economics

Economic incentives and disincentives exist that influence customer decisions about investing in or operating DERs. These derive from energy and demand tariffs and offerings, program opportunities, and financial policy incentives. The types of prices, program opportunities and incentives can vary significantly, influencing the overall economic calculation for investment and operation of DERs. Figure 5-1 characterizes the types of economic signals customers can experience which may affect capital investment. Items in red indicate cost factors whereas items in green indicate credits or incentives. The type of DER, its application and its location significantly influence both costs and incentives. For example, as part of the installation cost, CHP units may require outlays to set up fueling infrastructure. Furthermore, requirements around telemetry, controls, communication, and protection will vary depending on how you intend to use the DER, such as whether the asset is intended to be used for demand response services or whether it is simply run onsite to meet internal energy needs. In addition, incentives affecting capital can vary by DER type, and application, where incentives are contingent on technologies and interconnections. Further discussion is provided in Section 5.2 and 5.3 regarding incentive programs available across the United States and within New York.

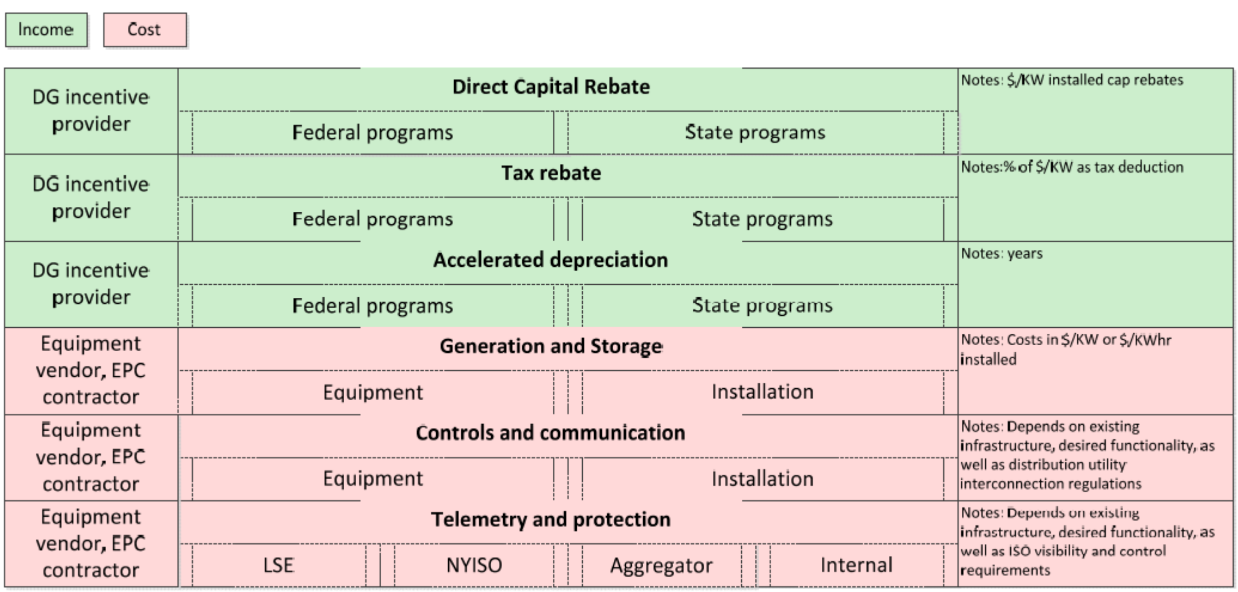


Figure 5-1. Economic Signals to Customers: Capital Investment Decisions

Figure 5-2 outlines economic signals affecting decisions around DER operations. Items in blue reflect production or operations-related incentives, those in green reflects income, and red reflects costs, which in some cases can be reduced or avoided depending on the operation of DERs. Again, DER type, application, and location can significantly influence which of these categories apply, and what the extent or value of these signals are. As described below, utility tariffs vary across the state and retailers and default offerings can be quite diverse. Furthermore, there are a diversity of demand response program offerings throughout the state, with customers able to participate in demand response through load serving entity programs or in wholesale markets through aggregators or its own participation. (Market product offerings and their availability to DERs is discussed further in Section 6).

Income | Cost | Rebate

DG incentive provider	Production incentives	Federal programs; State programs; LSE programs	Notes: $/KWh rebates. Might be related to fuel source and type for conventional generation sources
Own partiicpation	Market Products		Notes: $/KW and/or $/KWhr incentives
DR aggregator / LSE / own participation	DR programs		Notes: $/KW and/or $/KWhr incentives
Electric energy purchaser	Sell back rates	Net metering; Buy back; Sellback rate; Emergency generation	Notes: $/KWhr sold back
Electric energy provider	Electric energy charge	Hourly DAP; TOU rate; Flat rate	Notes: $/KWhr charge
T&D provider	Demand charge	TOU; Flat rate; Standby rate	Notes: $/KW charge
T&D provider	Distribution charge		Notes: $/KWhr charge
Gas provider	Flat rate gas cost		Notes: $/MMBtu charge

Figure 5-2. Economic Signals to Customers: Operating Decisions

Ultimately, customers may encounter a combination of economic signals from their load serving entity, wholesale, local, state, or federal government which can influence both how they operate their assets, and also whether they might invest in a given asset. Often, operational economics can influence investment decisions, but at times they may be independent. For example, a customer may purchase a behind-the-meter asset for one purpose, such as to improve reliability, but change their operations over time based on operating economics. Case studies in Section 5.4 provide examples of how varying rates, incentives and applications can change customer economics. In addition, further case studies, being developed by DNV GL with the support of NYSERDA will be released in the coming year.[129]

Customers may encounter a combination of economic signals from their load serving entity, wholesale operator, or local, state or federal government, which can influence both how they operate their assets and whether they might invest in a given asset.

5.2 Retail Rates, Regulations, and Incentives

5.2.1 Retail Rates

A variety of possible retail rate structures exist across the United States. Typically, rates consist of the following components:

[129] For more information, see: http://www.nyserda.ny.gov/BusinessAreas/Energy-Innovation-and-Business-Development/Research-and-Development/Research-Project/Research-Projects/Research-Project-Search-Results/Project-Information.aspx?p=9567&R=1&PDF=true

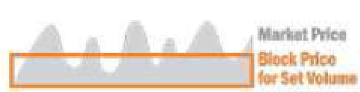
- **Energy Charge.** A charge to customers for the amount of energy consumed, often specified in $/kWh.
- **Demand charge.** A charge to customers based on their maximum demand for power. These charges can be assessed on a fixed or variable basis, where variable charges depend on the maximum demand within a specified time period.
- **Customer Charge.** A fee independent of consumption.

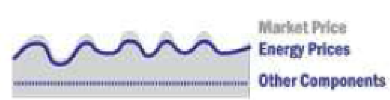
In addition, standby fees may be assessed to customers with behind-the-meter assets. Customers with DERs may need to supplement, or occasionally replace, their on-site generation with electricity from the grid. Stand-by rates are special rates that typically apply to station use by behind-the-meter generators. These rates are intended to cover utility fixed costs for the distribution and transmission network as well as other costs incurred by the utility due to the DER facility. Generally, a utility customer will pay a tariff in the form of a monthly demand charge per kW. In New York, customers subject to standby rates will generally pay a "contract demand" charge based on their maximum potential usage, and an "as used" demand charge based on their actual peak monthly usage. The intent is for utilities to use the contract demand charge to recover the cost of local facilities needed to serve the potential demand, and the as-used charge to recover a portion of the cost of shared facilities.[130] This is in addition to any electrical generation charges for actual electricity used. While standby rates may be a deterrent to DER, many facilities may be exempt from this charge – particularly if they count toward state renewable goals. As an example, the general rate rules for Con Edison list the following exemptions to standby service:[131]

1. On-site generation with a total nameplate rating of no more than 15% of total customer load
2. Customers with a contract demand of less than 50 kW
3. Designated technologies starting operation prior to May 31, 2015, such as:
    - Fuel cells, wind, solar thermal, PV, sustainably-managed biomass, tidal, geothermal, or methane waste; and
    - Small, efficient types of CHP generation not exceeding one MW in capacity; and

With regard to energy charges, they can often be described as fixed, variable, or a combination of fixed and variable:

- **Fixed.** Customer pays a set $/kWh value for all energy consumed;
- **Variable.** Customer pays based on dynamic $/kWh value. This value can change hourly or by peak and off-peak periods; or
- **Combination.** Customer pays a fixed rate for the pre-decided amount, then an indexed price for the remainder.





[130] NY PSC Case 99-E-1470
[131] https://www2.dps.ny.gov/ETS/jobs/display/download/5468808.pdf

In New York, large, utility-served loads are defaulted to Mandatory Hourly Pricing, though other pricing options are available.[132] Initially, the rate was applied to customers with a demand of 500 kW or greater for 2 out of 12 months. However, the rate has been extended to other groups, such as NYSEG customers with a demand of 300 kW or greater. Under this tariff, customers are billed hourly prices, based on NYISO day-ahead market prices, and with capacity charges and transmission and distribution losses applied.[133] Despite this shift to a default variable price, many customers have since chosen to switch to other rates from other load serving entities. In fact, as of May of 2013, roughly 73% of non-residential large time of use customers, representing 85% of load (kWh), had migrated to retail rate offerings.[134]

Many retailers exist within New York, and customers across all segments are procuring power from such providers. In several cases, retailers are combining energy delivery with other services, such as automated portfolio optimization, consulting services, and virtual generation possibilities. Figure 5-3 provides some example offerings within New York.

Supplier	Programs	
Constellation	**MVPe:** systematically removes market and timing risk through a mathematical algorithm that buys more energy when prices are historically lower and less at historic highs.	**Flexible Index Solutions:** offers the potential rewards of both budget stability and purchasing flexibility by allowing you to fix varying load-following percentages of electricity usage up to 100%.
Direct Energy	**PowerPortfolio:** is a customized, blended wholesale electricity procurement product that combines both fixed and variable priced strategies and an element of consultation.	
ConEd Solutions	**Energy Optimization Services:** leverage customer's participation in the energy markets by combining energy optimization strategies with economic opportunity. The Energy Optimization services include Demand Response Services and Virtual Generation Services.	**Virtual Generation:** Customers use this service to participate when market prices are high – throughout the year. ConEd Solutions sells customers' unused energy into the electricity grid for a profit.

Figure 5-3. Example Retail Rate Structures

Sources: http://www.constellation.com, http://www.directenergy.com, and http://www.conedsolutions.com

Generally, retail rates have increased over time across the U.S. Figure 5-4 shows average retail prices across all sectors, for New York, Hawaii, and California as well the average retail price for the United States.[135]

[132] On September 23, 2005 the PSC issued Order 03-E-0641 requiring utilities to implement Mandatory Hourly Pricing (MHP).

[133] While hourly pricing and time of use rates both vary by time of day, hourly pricing differs from time of use rates in that hourly prices are also dynamic and vary with wholesale prices. Time of use rates typically vary by hour of day but are static and independent of wholesale prices.

[134] DNV GL Retail Energy Outlook, May 2013.

[135] Average rates are adjusted to 2013 using annual average CPI.

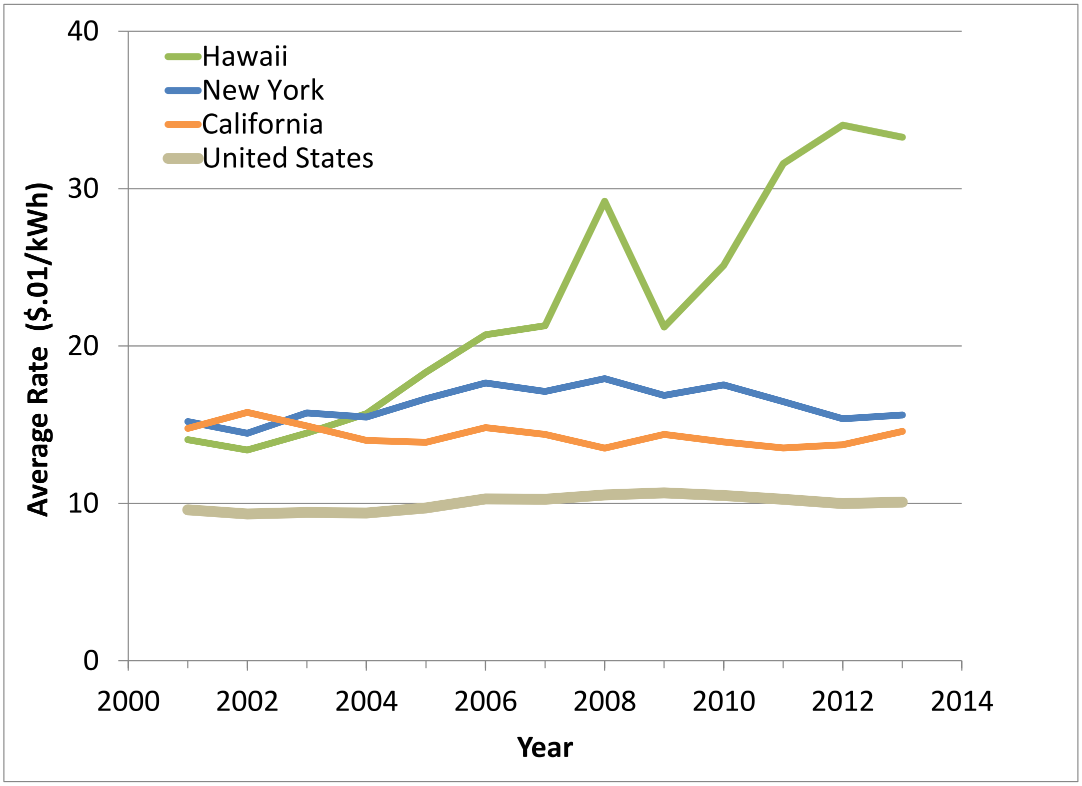


Figure 5-4. Average Retail Price Trends across All Sectors

Source: EIA, Obtained online 2014

New York average retail rate is relatively high compared to most state averages. However, as shown in Figure 5-5, average prices across all sectors have dropped within the past five years, compared recent increases observed in some places like Hawaii or California.

State	Res	Com	Ind	All
Hawaii	41%	43%	52%	44%
California	2%	0%	2%	1%
United States	-3%	-7%	-8%	-6%
New York	**-1%**	**-10%**	**-36%**	**-7%**

Figure 5-5. Average Retail Price 5-year % Change by Sector

Source: EIA, Obtained online 2014

In New York, delivery charges can vary quite significantly. Figure 5-6 illustrates average electricity prices for 2012, broken out by customer type and delivery versus supply components.

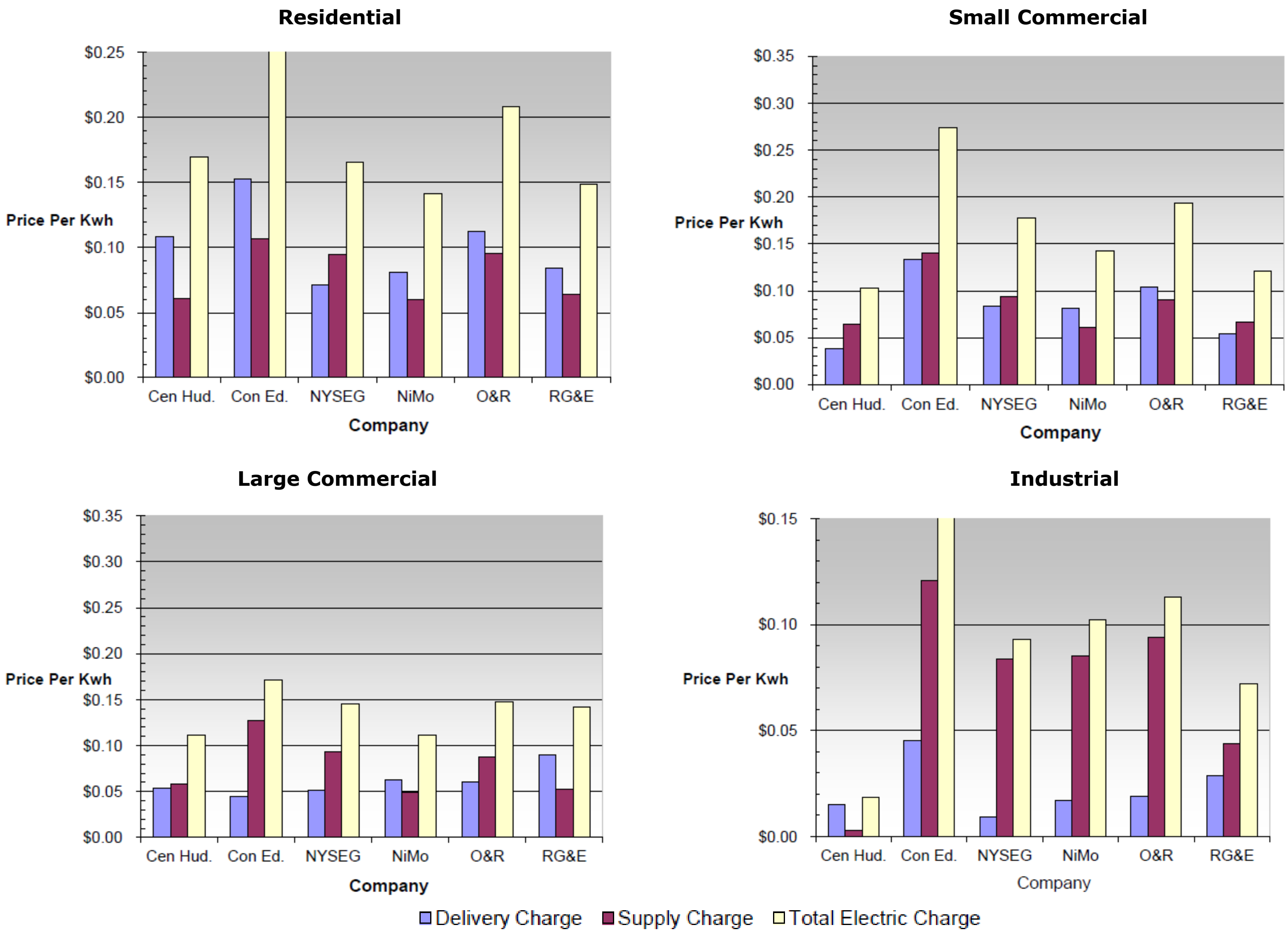


Figure 5-6. Comparison of Electricity Rates by Sector, Winter

Source: New York State Public Service Commission, Typical Customer Bill Information, Accessed 2014

5.2.2 Retail Regulations, Rules and Incentives

Grid owners and operators may have reason to incentivize certain types of DER adoption and behavior on their system. For example, by offering incentives, grid owners and operators could potentially motivate investment in particular locations or shift in operations to align customer benefits with grid benefits. This could potentially allow for the deferral of distribution, transmission or generation capacity investments. However, successful deferral depends on the coincidence of DER with local delivery system peaks or with system peaks (where demand for supply is high and supply is more limited), and reliable long-term capacity from these resources. As noted below in Section 5.3.4, Con Edison and NYSERDA are incentivizing 100 MW of storage and other DSM as well as 25 MW of CHP as a contingency for the possible 2016 summer closing of the Indian Point Energy Center. Alternatively, incentives can motivate a shift in DER operations, the location of DER investment, or investment in certain types of DERs technology. Operational benefits from DERs might include loss reductions or avoided energy purchases. The benefit of avoided energy depends on alternative costs for supply, which can vary by time of day. As seen in Section 4, emissions benefits are significantly dependent on the type of DER and supporting equipment. The same is true with voltage management and resiliency support. The following subsections provide insight into the types of DER-related incentives being used today across the United States and in New York, and note some recent evolution in incentive structures.

Grid owners and operators may have reason to incentivize certain types of DER adoption and behavior on their system to align customer benefits with grid benefits.

5.2.2.1 Net Metering

Net metering rules define the eligibility requirements, size and capacity and prices for DER energy that can be sold back to the grid at retail rates. In New York, net metering rules are defined in Public Service Law and are subject to rules as set by the PSC.[136] Under the various New York State rules, only certain resources, such as PV and CHP are eligible for net metering under the law. Figure 5-7 summarizes net metering rules and thresholds in New York for Investor-Owned Utilities (IOUs) with selected distributed technologies and the total capacity eligible for net metering in each IOU.

Eligible Technologies:	Solar			Biogas	Micro CHP	Fuel Cell		Wind		
Applicable Sectors (Residential, Non-Residential or Farm):	Res.	Non-Res.	Farm	Farm Waste	Res.	Res.	Non-Res.	Res.	Non-Res.	Farm
Limit on System Size:	25 kW	Up to 2MW	Up to 100kW	1 MW	10 kW	10 kW	Up to 1.5MW	25kW	Up to 2MW	500kW
Limit on Overall Enrollment:	3% of 2005 Electric Demand per IOU for Solar, Biogas, Micro CHP, Micro-hydroelectric and Fuel Cells combined; 0.3% for Wind.									

Figure 5-7: New York Net Metering Rules

Source: New York Public Service Commission

Net metering is available in most states, with the notable exception of Texas and a handful of other states which lack a state-wide net metering policy.[137]

In California, the CPUC regulates DER policies and programs on both the customer and utility (wholesale) side of the electric meter. Customer DER incentive programs in California includes the California Solar

[136] For more information, see: http://www.dsireusa.org/documents/Incentives/NY05R1.htm

[137] http://freeingthegrid.org/wp-content/uploads/2013/11/FTG_2013.pdf

Initiative and the Self-Generation Incentive Program. These programs are supported by the CPUC's oversight of Net Energy Metering (NEM) and Interconnection policies. Customers who install small solar, wind, biogas, and fuel cell generation facilities (1 MW or less) to serve all or a portion of onsite electricity needs are eligible for the state's net metering program. NEM allows a customer resource to receive a financial credit for power generated by their onsite system and fed back to the utility. The credit is used to offset the customer's electricity bill. NEM allows customers to receive the fully bundled retail rate for generation that offsets load (coincident or non-coincident), and may be expanded to cover net excess generation. This represents a stronger incentive than if exported energy were valued at the utility avoided cost rate, which may be as little as half of the retail rate. It also helps to reduce the concern for customers about volatility in renewable generation as load and generation do not have to be precisely coincident to return value to the customer.

In some utilities, there are concerns around certain aspects of net metering. For example, in July 2013 Southern California Edison released a memorandum about battery-backed storage systems and net metering eligibility, in which they expressed concern about the possibility of battery backed distributed solar selling non-renewable power back to the grid under the net metering tariff.[138] Though the CPUC has recently published a proposed decision on this issue, the concerns posed reflect some of the challenges that DERs (alone or in combination) can pose for existing policies.[139]

The number of customers with net metering has steadily grown over the years. According to data collected by the EIA since 2003, illustrated in Figure 5-8, the number of customers with net metering has grown by a factor of over 48 between 2003 and 2012.[140] The majority of net metering applies to PV units.

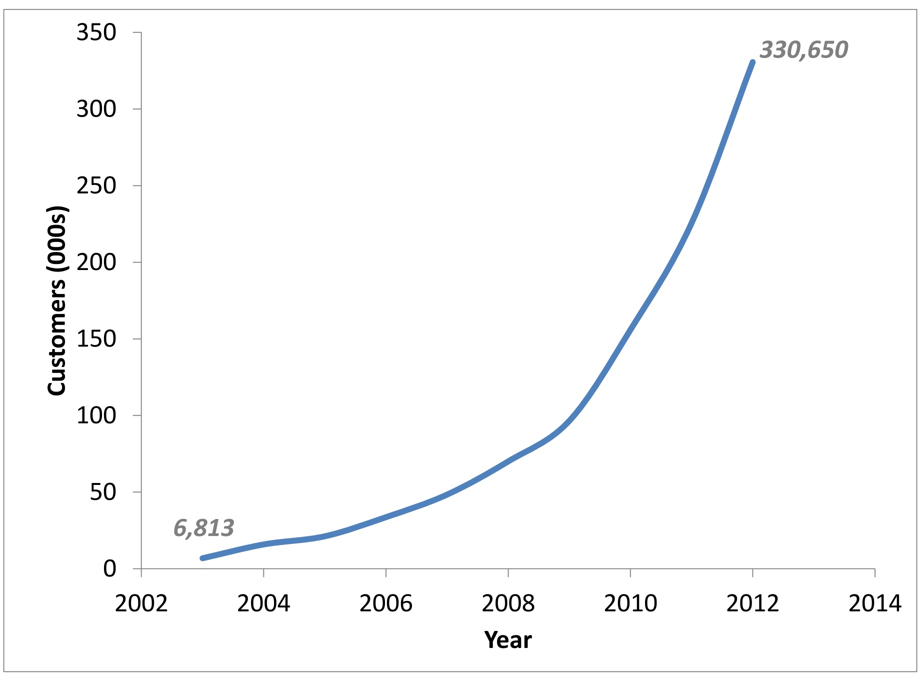


Figure 5-8. Customers with Net Metering

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138 For more information, see: https://www.sce.com/wps/wcm/connect/7bfb9fcc-b277-4646-9ac2-7700e03914bf/Battery_Backed_Storage_NEM_Eligibility.pdf?MOD=AJPERES

139 See http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M089/K641/89641289.PDF for more detail.

140 U.S. DOE, EIA, *Electric Power Annual 2012,* Table 4.10. Net Metering Customers and Capacity by Technology Type, by End Use Sector, 2013.

Source: Derived from EIA, Electric Power Annual 2012, 2013

Based on 2012 data from EIA, New York ranks within the top ten states for estimated total capacity that is net metered.[141] California, New Jersey and Arizona represent the top three states, and PV constitutes the majority of DER type for all four states. Figure 5-9 illustrates these findings.

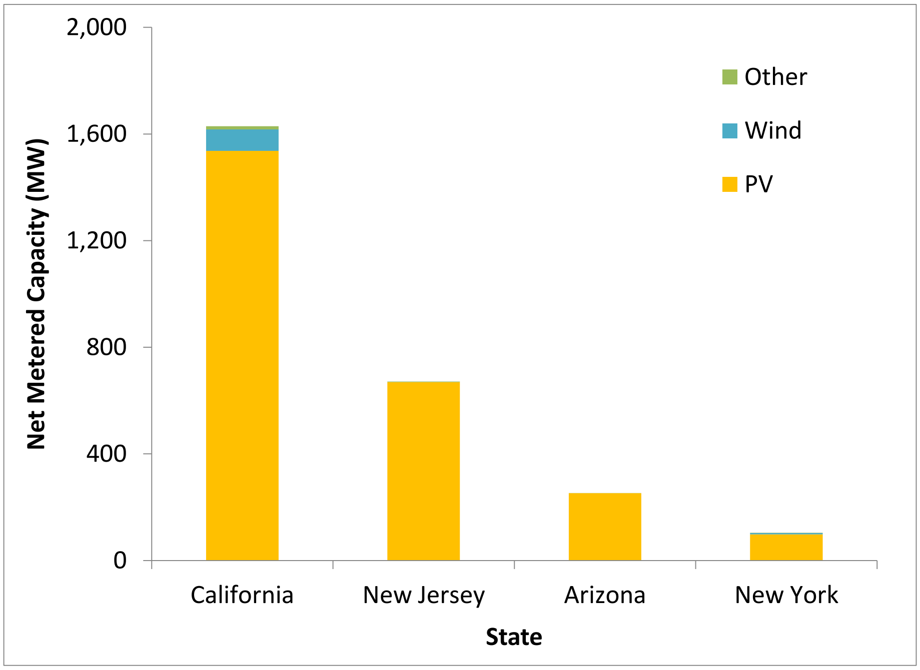

Figure 5-9. Estimated Net Metered Capacity by State

Source: Derived from EIA Form 861 Data for 2012

5.2.2.2 Value of Solar

Selected utilities have implemented alternative approaches to net metering for compensation of excess production. For example, Austin Energy has implemented a Value of Solar Tariff. Rather than applying net metering, Austin Energy bills customers at the full retail rate for their load and separately credits them the determined 'value of solar' for each kWh they generate. The 'value of solar' is calculated annually based on loss savings, energy savings, generation capacity savings, fuel price hedge value, transmission and distribution capacity savings, and environmental benefits. This value is intended to be the "break-even" value for the utility. In 2014, the value was recalculated to 0.107 $/kWh from 0.128 $/kWh, representing a 16% decrease over the past year.[142]

Similarly, legislation passed in 2013 requires the Minnesota Department of Commerce to establish a Value of Solar (VOS) Methodology.[143] As an alternative to net metering, investor-owned utilities may apply to the Minnesota Public Utilities Commission for a value of solar tariff that compensates customers through a credit for the value to the utility, its customers, and society for operating distributed PV systems interconnected to the utility and operated by the customer primarily for meeting their own energy needs.

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[141] DOE, EIA Form 861 surveys utilities, asking for information on systems 2 MW or smaller. See http://www.eia.gov/survey/form/eia_861/instructions.pdf for more information.; DOE, EIA Form 861, 2012 survey results. See http://www.eia.gov/electricity/data/eia861/ for more information.

[142] http://www.irena.org/DocumentDownloads/Publications/policy_adaptation.pdf

[143] https://mn.gov/commerce/energy/topics/resources/energy-legislation-initiatives/value-of-solar-tariff-methodology%20.jsp

5.2.2.3 Feed-In-Tariffs

FITs are used to a limited extent in the United States, but are more common internationally. A FIT program typically guarantees that customers who own a FIT-eligible renewable electricity generation facility, such as a roof-top solar photovoltaic system, will receive a set price from their utility for all of the electricity they generate and provide to the grid.

FITs or variations of FITs exist on the West Coast and parts of the Midwest, South and East Coast of the United States. Figure 5-10 highlights offerings by state, reflecting information gathered by the U.S. EIA in 2013.

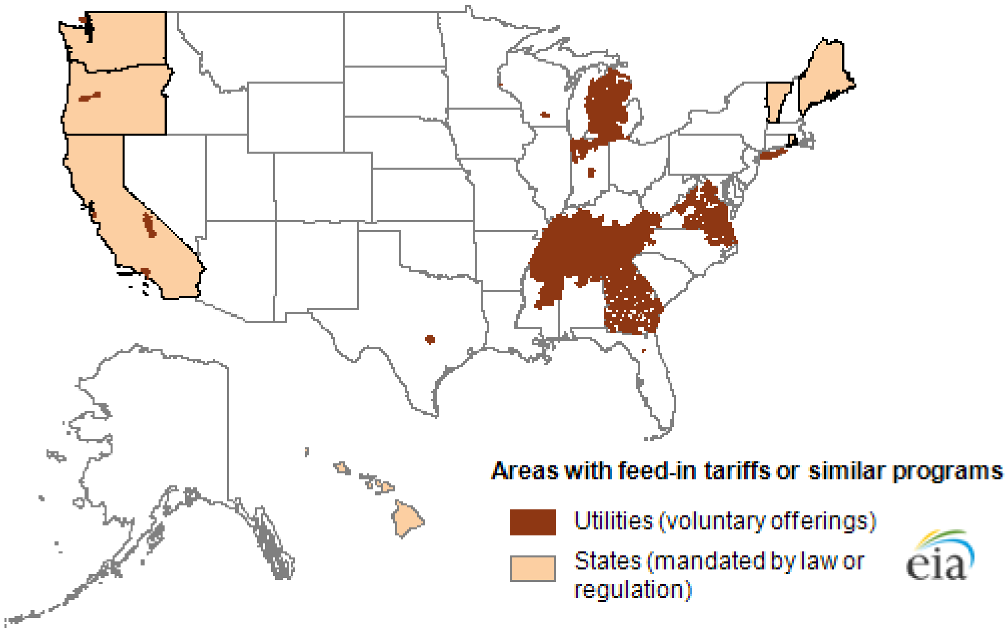

Figure 5-10. Feed in Tariff Programs across the U.S.

Source: EIA, 2013

In the United States, different models are used by each utility either voluntarily or in response to state or local government mandates. Appendix X outlines some of the existing FIT programs as of May 2013 across different utilities in the United States. Among the U.S. programs is a program by the Long Island Power Authority (LIPA) called the CLEAN Solar Initiative FIT. With several successful iterations in the past, the current program has a cumulative program target of 100 MW of additional solar energy. The program will set 20-year contracts at a rate of $0.1688/kWh.[144]

5.3 Government Incentive Programs

A variety of incentive offerings applicable to DERs exist across the country. Federal, state and local incentives are often used to help meet policy goals that promote energy objectives such as resiliency and security or emissions reductions. The following subsections outline types of policies used in the U.S. and in New York.

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[144] PSEG Long Island Press Release, April 2, 2014. Available online at: https://www.psegliny.com/page.cfm/AboutUs/PressReleases/040214-solar

5.3.1 Current incentives programs used across the United States

Federal incentive programs are generally geared towards supporting state or local governments in reaching their energy, efficiency and development goals by providing grants, loan guarantees or corporate or personal tax incentives to eligible projects. Some of these incentives are also aimed at rural communities and combine goals for economic development and environmental protection. Figure 5-11 provides an overview of available, federal incentives that may apply to DERs.

Incentive Type/Name	Eligible Technologies				Applicable Sectors					
	Renewables	CHP	EE	Other	Utility	C&I	Agricultural /Rural	Residential	Local /State / Tribal Gov.	Others
Corporate Depreciation										
Modified Accelerated Cost-Recovery System (MACRS)	✓	✓		✓		✓	✓			
Corporate Exemption										
Residential Energy Conservation Subsidy Exclusion (Corporate)	✓							✓		
Corporate Tax Credit										
Business Energy Investment Tax Credit (ITC)	✓	✓		✓	✓	✓	✓			
Federal Grant Program										
USDA - Rural Energy for America Program (REAP) Grants	✓	✓	✓	✓			✓		✓	✓
Federal Loan Program										
Energy-Efficient Mortgages	✓		✓					✓		
Qualified Energy Conservation Bonds (QECBs)	✓								✓	
USDA - Loan Guarantee Programs (several)	✓	✓		✓	✓	✓	✓		✓	
Personal Exemption										
Residential Energy Conservation Subsidy Exclusion (Personal)	✓		✓					✓		
Personal Tax Credit										
Residential Renewable Energy Tax Credit	✓			✓				✓		

Figure 5-11. Federal Incentives for DER

Source: DSIRE[145]

Incentives are often renewed in stages, so while programs may have expired or application deadlines have passed, it is feasible that many will be renewed or similar initiatives would be enacted. While many of the listed incentives may apply to DER indirectly, the federal business energy investment tax credit (ITC), the Rural Energy for America Program (REAP) and residential renewable energy tax credit are examples of programs more directly suited for DER installations.

The ITC was expanded significantly by the Energy Improvement and Extension Act of 2008.[146] This law extended the duration - by eight years - of the existing credits for solar energy, fuel cells and microturbines; increased the credit amount for fuel cells; established new credits for small wind-energy systems and CHP systems; allowed utilities to use the credits; and allowed taxpayers to take the credit against the alternative minimum tax (AMT), subject to certain limitations. The credit was further expanded by the American Recovery and Reinvestment Act of 2009, enacted in February 2009.

[145] http://www.dsireusa.org/

[146] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F

Federal Incentive Overview - Business Energy Investment Tax Credit (ITC)	
State	Federal
Incentive Type	Corporate Tax Credit
Eligible Technologies	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Wind, Geothermal Electric, Fuel Cells, Geothermal Heat Pumps, Municipal Solid Waste, CHP/Cogeneration, Solar Hybrid Lighting, Tidal Energy, Fuel Cells using Renewable Fuels, Microturbines, Geothermal Direct-Use
Applicable Sectors	Commercial, Industrial, Utility, Agricultural
Amount	30% for solar, fuel cells, small wind* 10% for geothermal, microturbines and CHP
Maximum Incentive	Fuel cells: $1,500 per 0.5 kW Microturbines: $200 per kW Small wind turbines placed in service 10/4/08 - 12/31/08: $4,000 Small wind turbines placed in service after 12/31/08: no limit All other eligible technologies: no limit
Eligible System Size	Small wind turbines: 100 kW or less Fuel cells: 0.5 kW or greater Microturbines: 2 MW or less CHP: 50 MW or less*
Equipment Requirements:	Fuel cells, microturbines and CHP systems must meet specific energy-efficiency criteria

Figure 5-12 gives an overview of the ITC requirements.

Federal Incentive Overview - Business Energy Investment Tax Credit (ITC)	
State	Federal
Incentive Type	Corporate Tax Credit
Eligible Technologies	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Wind, Geothermal Electric, Fuel Cells, Geothermal Heat Pumps, Municipal Solid Waste, CHP/Cogeneration, Solar Hybrid Lighting, Tidal Energy, Fuel Cells using Renewable Fuels, Microturbines, Geothermal Direct-Use
Applicable Sectors	Commercial, Industrial, Utility, Agricultural
Amount	30% for solar, fuel cells, small wind* 10% for geothermal, microturbines and CHP
Maximum Incentive	Fuel cells: $1,500 per 0.5 kW Microturbines: $200 per kW Small wind turbines placed in service 10/4/08 - 12/31/08: $4,000 Small wind turbines placed in service after 12/31/08: no limit All other eligible technologies: no limit
Eligible System Size	Small wind turbines: 100 kW or less Fuel cells: 0.5 kW or greater Microturbines: 2 MW or less CHP: 50 MW or less*
Equipment Requirements:	Fuel cells, microturbines and CHP systems must meet specific energy-efficiency criteria

Figure 5-12. Business Energy Investment Tax Credit (ITC) Overview

*Notes: * A number of changes to this credit are scheduled to take effect for systems placed in service after December 31, 2016. Please see the DSIRE website for more information.*

Source: DSIRE[147]

The REAP Grants promote energy efficiency and renewable energy for agricultural producers and rural small businesses through the use of (1) grants and loan guarantees for energy efficiency improvements and renewable energy systems, and (2) grants for energy audits and renewable energy development assistance.

[147] Available online at: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F&re=1&ee=1

Federal Incentive Overview - USDA - Rural Energy for America Program (REAP) Grants	
State	Federal
Incentive Type	Federal Grant Program
Eligible Efficiency Technologies	Unspecified Technologies
Eligible Technologies	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydroelectric, Geothermal Electric, Geothermal Heat Pumps, CHP/Cogeneration, Hydrogen, Anaerobic Digestion, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal, Renewable Fuels, Fuel Cells using Renewable Fuels, Microturbines, Geothermal Direct-Use
Applicable Sectors	Commercial, Schools, Local Government, State Government, Tribal Government, Rural Electric Cooperative, Agricultural, Institutional, Public Power Entities
Amount	2013 Renewable Grants: $2,500-$500,000 2013 Efficiency Grants: $1,500-$250,000 Loan and Grant Combination: Grant portion must exceed $1,500
Maximum Incentive	25% of project cost
Start Date	FY 2003

Figure 5-13 provides an overview of REAP requirements.

Federal Incentive Overview - USDA - Rural Energy for America Program (REAP) Grants	
State	Federal
Incentive Type	Federal Grant Program
Eligible Efficiency Technologies	Unspecified Technologies
Eligible Technologies	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydroelectric, Geothermal Electric, Geothermal Heat Pumps, CHP/Cogeneration, Hydrogen, Anaerobic Digestion, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal, Renewable Fuels, Fuel Cells using Renewable Fuels, Microturbines, Geothermal Direct-Use
Applicable Sectors	Commercial, Schools, Local Government, State Government, Tribal Government, Rural Electric Cooperative, Agricultural, Institutional, Public Power Entities
Amount	2013 Renewable Grants: $2,500-$500,000 2013 Efficiency Grants: $1,500-$250,000 Loan and Grant Combination: Grant portion must exceed $1,500
Maximum Incentive	25% of project cost
Start Date	FY 2003

Figure 5-13. Rural Energy for America Program (REAP) Grants Overview

Source: DSIRE[148]

Established by The Energy Policy Act of 2005, the federal tax credit for residential energy property initially applied to solar-electric systems, solar water heating systems, and fuel cells.[149] The tax credit has since been expanded in several phases to include small wind-energy systems and geothermal heat pumps,

[148] Available online at: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US05F&re=1&ee=1

[149] Residential energy property refers to eligible equipment that serves a dwelling located in the United States that is owned and used as a residence by the taxpayer. Source: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US05F&re=1&ee=1

removed the maximum credit amount for eligible technologies and has been extended to December 31, 2016.[150] Figure 5-14 gives an overview of the requirements for the residential renewable energy tax credit.

Federal Incentive Overview - Residential Renewable Energy Tax Credit	
State	Federal
Incentive Type	Personal Tax Credit
Eligible Renewable/Other Technologies	Solar Water Heat, Photovoltaics, Wind, Fuel Cells, Geothermal Heat Pumps, Other Solar-Electric Technologies, Fuel Cells using Renewable Fuels
Applicable Sectors	Residential
Amount	30%
Maximum Incentive	Solar-electric systems placed in service after 2008: no maximum Solar water heaters placed in service after 2008: no maximum Wind turbines placed in service after 2008: no maximum Geothermal heat pumps placed in service after 2008: no maximum Fuel cells: $500 per 0.5 kW
Eligible System Size	Fuel cells: 0.5 kW minimum
Equipment Requirements	Solar water heating property must be certified by SRCC or a comparable entity endorsed by the state where the system is installed. At least half the energy used to heat the dwelling's water must be from solar. Geothermal heat pumps must meet federal Energy Star criteria. Fuel cells must have electricity-only generation efficiency greater than 30%.

Figure 5-14. Residential Renewable Energy Tax Credit Overview

Source: DSIRE[151]

5.3.2 State and Local Programs

Renewable Portfolio Standards and Distributed Generation Targets

At the state and local levels, there are multiple incentive types and programs available. In states with Renewable Portfolio Standards (RPS), many utilities are required to procure renewable energy to meet certain targets. This is often done through utility rebate programs or other financial incentives. In some cases, there are special carve-outs for distributed renewables. In total, 29 states have renewable portfolio standards and 16 of these states have carve-outs for solar or another form of distributed generation. A sample of those with relatively high percentage targets are listed in Figure 5-15.

[150] Ibid.

[151] Available online at; http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US37F&re=1&ee=1

State	RPS Target %	Applicable Target Year	Distributed Generation Carve-out
Arizona	15%	2025	4.5%
California	33%	2020	-
Colorado	30%	2020	3%
Hawaii	40%	2030	-
Illinois	25%	2025	0.25%
New Mexico	20%	2020	0.6%
New York	30%	2015	2% - details below
Maine	30%	2020	-

Figure 5-15. RPS with DG Targets for Selected States

Source: DSIRE

The PSC adopted a RPS for New York in September 2004. In its current implementation, the RPS states a target of 30% of state electricity consumption from renewables by 2015.

The New York RPS energy target specifies three categories:

- **Main Tier or Large Scale Generators.** Large scaled generators that sell power to the wholesale grid or in some cases generate power for onsite use.
- **Customer-Sited Tier.** Small scaled generators such as a PV system at a residence.
- **Other Market Activities.** Individuals and businesses that choose to pay a premium on their electricity bill to support renewable energy and state agencies that are subject to renewable energy purchasing requirements through similar policies.

The Main Tier and Customer-Sited Tier (CST) programs are to be run by NYSERDA. In its April 2, 2010 Order, the PSC established targets for these programs of approximately 10.4 million MWh of renewable energy annually by 2015, with 0.9 million MWh of this target from CST programs, based on the 2012 CST Program Operating Plan.[152] Recent PSC Orders have further modified the allocation of funds between Main-Tier and CST programs, and provided NYSERDA more flexibility in allocating funds based on geography and performance. For instance, in a December 19, 2013 Order the PSC authorized NYSERDA to reallocate $108 million of unencumbered Main Tier funds to support the CST solar PV programs through 2015 and in April 2014, the PSC authorized the new MW Block program design for the NY-Sun initiative.[153]

Other Incentives

Several state and local incentives are geared towards energy efficiency improvements, including the Property Assessed Clean Energy (PACE) financing initiatives. PACE is an innovative way to finance energy efficiency and renewable energy upgrades to buildings via property tax assessments. To date, 31 states and the District of Columbia have PACE enabling legislation.[154] In New York, the PSC has established an energy efficiency goal to reduce New Yorkers' electricity usage 15% of forecast levels by the year 2015, with comparable results in natural gas conservation, via the New York Energy Efficiency Portfolio Standard (EEPS)

[152] *Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard*, "Order Authorizing Customer Sited Tier Program Through 2015 and Resolving Geographic Balance and Other Issues Pertaining to the RPS Program;" "Order Resolving Main Tier Issues;" issued and effective April 2, 2010.

[153] New York State Renewable Portfolio Standard Annual Performance Report Through December 31, 2013, Final Report March 2014.; http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=17612

[154] For more information, see: http://pacenow.org

proceeding. Since June 2009 the NY PSC has approved over 90 electric and gas energy efficiency programs, along with rules to guide implementation and measure results.

In addition, many states offer tax incentives geared towards renewables (typically PV) and energy efficiency (including CHP), such as sales tax exemptions and corporate tax credits. For DERs on the utility side of the meter, many states, including New York, California, and Hawaii, offer FITs as a way to encourage the deployment of DERs.

5.3.3 Current Incentive Programs used in New York

This year, the PSC has launched an initiative, Reforming the Energy Vision (REV), to encourage deeper penetration of DERs, engage end-users, promote efficiency and wider use of distributed resources, as well as meet the challenges of aging infrastructure and severe weather events.[155] The PSC Chair, Audrey Zibelman, has outlined a goal to decentralize the grid and engage consumers, allowing DERs to play an active role in grid management.[156] Via the REV initiative, the PSC aims to accomplish six core objectives, including:[157]

1. improving customer knowledge;
2. market animation;
3. system-wide efficiency;
4. system reliability and resiliency;
5. fuels and resource diversity; and
6. carbon reduction.

Under the current framework, the regulatory changes will be addressed in two tracks: The first track will examine the role of distribution utilities in enabling market-based deployment of DERs to promote load management and greater system efficiency, including peak load reductions. The second track would examine changes in current regulatory, tariff, and market designs and incentive structures to better align utility interests with the policy objectives.

In addition, in January 2014, the State published a draft State Energy Plan, describing several new and on-going initiatives, policies, and programs to meet State and local energy goals.[158] Figure 5-16 highlights initiatives within this plan that touch on DERs and align with objectives in the REV.

New York State Initiative	Description
Build Smart NY	This initiative, aimed at reducing energy consumption in State buildings with 20% by 2020, includes a benchmarking energy-use study and the development of energy master plans for Albany, Buffalo, Rochester, Syracuse, and Yonkers.
Charge NY	Supporting the installation of more than 3,000 public and workplace charging stations over five years, this program aims at making electric vehicles (EVs) more economically viable and easy to use in New York.

155 http://www3.dps.ny.gov/W/PSCWeb.nsf/ArticlesByTitle/26BE8A93967E604785257CC40066B91A?OpenDocument
156 http://www.restructuringtoday.com/public/13625.cfm
157
http://www3.dps.ny.gov/W/PSCWeb.nsf/ArticlesByTitle/26BE8A93967E604785257CC40066B91A?OpenDocument

158 See http://energyplan.ny.gov/Plans/2014.aspx for more details.

New York State Initiative	Description
Cleaner Greener Communities	This program is designed to empower New York's ten regions to create more sustainable communities by funding smart growth practices. It has two phases; the first phase, which is completed, was to create regional sustainability plans. The program is now during its second phase and is selecting smart development projects for integrated, sustainable solutions.
Energy Efficiency Portfolio Standard	The PSC established an energy efficiency goal to reduce New Yorkers' electricity usage 15% of forecast levels by the year 2015, with comparable results in natural gas conservation.
NY Energy Highway	An initiative to upgrade and modernize New York's electric grid for increased capacity and flexibility, including the development of an Energy Management Control Center. In addition, the PSC is developing an Indian Point Contingency Plan.
NY Green Bank	A green bank is a public or quasi-public financing institution that provides low-cost, long-term financing support to clean, low-carbon projects by leveraging public funds through the use of various financial mechanisms to attract private investment. The Connecticut Clean Energy Finance and Investment Authority is the first state-level green bank, which was created in 2000 by the Connecticut Legislature. In January 2013, Governor Cuomo called for the establishment of a $1 billion New York Green Bank to attract private sector capital to clean energy system, and increase overall capital availability through financial support options such as credit enhancement, project aggregation, and securitization.
NY-Sun	A public-private partnership making solar technology more affordable by reducing balance-of-system solar costs and expanding incentive programs for solar deployment.
ReBuild NY	In the wake of Superstorm Sandy and other extreme weather events, this program focuses on reliability and resiliency of the electric power supply. Actions include building redundancies into the fuel delivery system and strengthening PSC's regulatory and enforcement oversight.
ReCharge NY	A Statewide economic development initiative focused on retaining and creating jobs by providing financial certainty to growth industries through long-term contracts of low-cost power.
Regional Greenhouse Gas Initiative	A cooperative effort among Northeast and Mid-Atlantic states to cap and cost-effectively reduce greenhouse gas emissions from the power sector.
Renewable Portfolio Standard (RPS)	A policy created to increase the amount of electric energy that is derived from renewable sources, such as solar and wind, to 30% by 2015.

Figure 5-16. New York State Energy Initiatives under the Draft State Energy Plan

Source: 2014 Draft New York State Energy Plan

In parallel, NYSERDA administers several incentive programs targeting renewables, energy efficiency and sustainability. Sample programs related to DERs include:

- **Solar PV Program Financial Incentives.** The program provides incentives to customers wishing to install new grid-connected Solar Electric or PV systems. Residential incentives are capped at 25 kW of capacity and commercial incentives are capped at 200 kW.[159] Customers with system capacities greater than these caps are only eligible for funding up to their corresponding capacity cap. As of June 2014, the individual project incentive rate is $1 per Watt up to the first 50kW of system size. Additionally, a second tier incentive of $0.6 per Watt is available for systems greater than 50kW up to 200kW.[160]

- **Solar Thermal Incentive Program.** New York State provides financial incentives to qualified customers for installing solar thermal systems. Individual incentives are paid at a rate of $1.5 per kWh for Non-RPS funding based on estimated displaced electrical usage.[161] The incentive is capped to 80% of the base (existing) thermal load. and is expected to cover 15-20% of the installed cost for a solar thermal system.[162]
- **CHP Performance Program.** Customers with CHP systems with a capacity of 1.3 MW or more that provide summer peak demand reduction are eligible for the CHP Incentive Program.[163] These incentives are paid based on the summer peak demand reduction in kW, energy generation in kWh, and fuel conversion efficiency achieved by the CHP system on an annual basis over a two-year measurement and verification period. Incentive rates are presented in the figure below.

Base Incentives	Upstate	Downstate**
Electricity Generation	$0.10 x kWh	$0.10 x kWh
Peak Demand Reduction*	$600 x kW	$750 x kW

Figure 5-17. CHP Incentive Program

**kW is summer peak demand reduction, not installed capacity*
***Electric and/or Gas Utility customers paying into the System Benefits Charge within the following counties: Bronx, Kings, Nassau, New York, Queens, Richmond, Suffolk and Westchester*

Source: NYSERDA 2014[164]

CHP Systems may receive up to 30% bonus incentive above the base incentive if they meet certain criteria, including projects that serve critical infrastructure, projects within a load service area of particular interest by Consolidated Edison called a Targeted Zone, and projects that exhibit superior performance. The maximum incentives (base and bonus incentives combined) per CHP project are capped at the lesser of $2,600,000 or 50% of total project cost.

- **CHP Acceleration Program.** The CHP Acceleration Program provides incentives for the installation of CHP systems by approved CHP system vendors in the size range 50 kW – 1.3 MW.[165] The maximum incentive per project, including bonuses, is $1,500,000.[166]

In addition to state-wide initiatives, several cities within New York have energy plans in place or under development. For example, in 2011, the New York City government published a city energy plan with the

159 NYSERDA, May 2014, https://www.nyserda.ny.gov/-/media/Files/FO/Current%20Funding%20Opportunities/PON%202112/2112summary.pdf
160 Viewed June 2014, https://www.nyserda.ny.gov/Energy-Efficiency-and-Renewable-Programs/Renewables/Solar-Technologies/PV-Funding-Balance.aspx
161 NYSERDA, https://www.nyserda.ny.gov/-/media/Files/FO/Current%20Funding%20Opportunities/PON%202149/2149alldocs.pdf
162 Ibid.
163 NYSERDA, Combined Heat and Power (CHP) Performance Program. Available online at: http://www.nyserda.ny.gov/Energy-Efficiency-and-Renewable-Programs/Commercial-and-Industrial/CI-Programs/Combined-Heat-and-Power.aspx. Last updated June 13, 2014.
164 Ibid.
165 NYSERDA, Combined Heat and Power (CHP) Acceleration Program. Available online at: http://www.nyserda.ny.gov/-/media/Files/FO/Current%20Funding%20Opportunities/PON%202568/2568AllDocs.pdf. August, 2013.
166 Ibid.

explicit goal to "build a greener, greater New York by reducing energy consumption and making our energy supply cleaner, more affordable, and more reliable."[167] It highlights some key challenges in New York City: reliability, emissions, limited real estate, aging infrastructure, and limited transmission capacity into the city. While a large portion of the plan targets energy efficiency measures, particularly around buildings and lighting, many of the goals outlined in the plan can be addressed with DERs. For instance, building efficiency can be improved with CHP units, the carbon foot print for hospitals or university campuses can be reduced with energy efficiency or PV, and constrained transmission and distribution lines can be relieved with on-site peak generation. Initiatives in the NYC Energy plan relevant to DER are highlighted in Figure 5-18.

New York City Initiative	Description
NYCEEC - The New York City Energy Efficiency Corporation - to provide energy efficiency financing and information	NYCEEC is a not-for-profit corporation intended to make energy efficiency financing less risky for lenders and more accessible to property owners. NYCEEC is capitalized with federal stimulus funding and organized to partner with the commercial lending industry and philanthropic sources.
The Mayor's Carbon Challenge	In 2007, Mayor Bloomberg issued a challenge to the city's largest universities and hospitals to match the City's goal of reducing carbon emissions 30% in ten years. The challenge is now expanded to include other sectors and higher targets. DER can be a solution for many campuses to meet this goal.
I N I T I A T I V E 1 3 To "Encourage the development of clean distributed generation"	A goal to develop 800 MW of clean DG, including CHP, on city-owned sites. In addition, the city seeks to • Streamline the permitting and interconnection process for DG on private building sites via a centralized website for permit application and tracking • Improve coordination of electric and gas distribution planning to help ensure adequate gas supply and access to demand response markets for DG • Advocate for ratepayer funded incentives for DG
I N I T I A T I V E 1 4 To "Foster the market for renewable energy in New York City"	The City has several efforts under way: • Solar property tax abatement • Expanded "net metering" rules • Online tool to determine the potential for generating solar power on rooftops • PV monitoring system to analyze coincident peak generation • Small wind projects on city land (landfills)
I N I T I A T I V E 1 7 To "Develop a smarter and cleaner electric utility grid for New York City"	The City will deploy an Energy Enterprise Metering System (EEMS) in thousands of its buildings. This real-time information system will facilitate the integration of clean DG, including EVs. Efforts include • Peak load management increased from 17 MW to 50 MW • Microgrid pilots in Long Island City and Brooklyn Army Terminal.

Figure 5-18. New York City Energy Initiatives under the State Energy Plan

[167] For additional detail, see http://nytelecom.vo.llnwd.net/o15/agencies/planyc2030/pdf/planyc_2011_energy.pdf

Source: *The City of New York 2011*[168]

5.3.4 Emerging Trends in Incentives and Policy Focus

Traditionally, incentives have been structured as direct subsidies, such as investment and production tax credits, with the goal for renewables, energy storage and other alternative energy resources to gain a foot hold in established energy markets. Recently, however, new approaches to supporting the transformation in the energy industry are emerging. Initiatives like the New York Green Bank help move the market by providing viable financing options while performance-based incentives, such as the CHP Performance Program, tie DER performance targets to system-wide objectives such as peak-shaving.[169] New tariff designs, such as the Austin Energy Value of Solar tariff, aim to take a system-view in compensating the owner of distributed PV such that benefits to the grid from DER as well as integration costs are evaluated in a market context.[170]

Traditionally, incentives have been structured as direct subsidies. Recently, however, new approaches to supporting DERs are emerging.

In a related development, NYSERDA is implementing the MW Block program with the goal to provide more certainty and transparency to the industry regarding incentive levels. The MW Block program concept is also intended to account for regional market differences and signal to the industry the intention to transition away from direct cash incentives. NYSERDA filed a design concept and funding plan for the MW Block on January 6, 2014, which was then approved in a NY PSC order on April 24, 2014.[171] The MW Block program includes a statewide capacity goal of 3,000 MW, and differentiates three distinct regions in the State: Long Island, New York City metropolitan area, and the rest of the state (ROS). The program addresses three separate market segments:

- Systems up to 50 kW in size (small);
- Systems greater than 50 kW up to 200 kW (medium); and
- Systems greater than 200 kW up to 2 MW (large).

In the proposed program design, the incentive will be a capacity based standard offer incentive for small and medium sized systems, and a performance-based incentive for large systems.[172]

Another recent development is the approval of a contingency plan for the retiring Indian Point Energy Center (IPEC), which in part relies on demand-side resources. In November 2013, the PSC approved the IPEC Reliability Contingency Plan, where 2,040 MW of nuclear generating capacity (roughly the equivalent to 20% of NYC base load) is assumed to retire by 2015.[173] In addition to transmission and generation projects, the plan calls for 100 MW of peak demand reduction through targeted demand response and energy efficiency programs and 25 MW of CHP capacity. The demand reduction effort focuses on reducing system peak demand through a range of technologies, including thermal storage (i.e. ice), electricity storage (i.e. batteries), HVAC, lighting/LED, and fuel switching. The programs would be administered by Consolidated

[168] Available online at: http://nytelecom.vo.llnwd.net/o15/agencies/planyc2030/pdf/planyc_2011_energy.pdf

[169] http://greenbank.ny.gov/; http://www.nyserda.ny.gov/Energy-Efficiency-and-Renewable-Programs/Commercial-and-Industrial/CI-Programs/Combined-Heat-and-Power.aspx

[170] http://austinenergy.com/wps/portal/ae/about/news/press-releases/2013/new-value-of-solar-rate-takes-effect-january

[171] http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=17612

[172] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={EDB54E42-13EA-4817-8F5C-8E3165D78919}

[173] CASE 12-E-0503, ORDER ACCEPTING IPEC RELIABILITY CONTINGENCY PLANS

Edison and NYSERDA, and a cost allocation and recovery plan was filed on February 3, 2014. The total cost for the 125 MW of proposed energy efficiency, demand response and CHP projects is estimated at $285 million. Of this, the 25 MW Expanded NYSERDA CHP Program is expected to be $66 million, broken down into:

- $40 million for customer incentives;
- $16 million for Outreach Assistance Contractor activities; and
- $10 million for administrative functions such as NYSERDA staff salaries and State Cost Recovery Fee and Program.

The energy efficiency and demand response budget totals $219 million, with the following targets by technology type:

- **Thermal Storage.** 15 MW
- **Battery Storage.** 12 MW
- **DR Enablement.** 8 MW
- **Building Management Systems.** 9 MW
- **Chiller/HVAC.** 13 MW
- **Lighting.** 27 MW
- **Steam Chiller.** 16 MW

The NYSERDA MW Block Program and the IPEC Reliability Contingency Plan suggest an increased focus on the value that DERs can deliver to the grid in addressing reliability, environmental and efficiency needs.

5.4 Example Case Studies of Customer Economics

As noted earlier, the economics of DER will vary significantly per customer due to differences in technologies, applications, policies, and incentives shaping the capital and operational costs and benefits. To highlight some of this variation and to illustrate how these factors affect project outcomes, DNV GL developed and gathered information on sample use cases. Additionally, New York-specific use cases are currently being developed separately by NYSERDA, DNV GL and others.

5.4.1 Photovoltaic Solar and Tariffs

A 2012 study by NREL explored how the value of PV varies according to:[174]

- Building types (and associated load profiles)
- Electricity rates and
- PV size relative to building load.

Figure 5-19 illustrates how the value of PV to a customer can change with changes in rates, for the same load profile and PV installation. Penetration refers to the PV percentage share of the building load. PV value is calculated as the change in a customer's energy bill (assuming least cost rates with and without PV) in

[174] NREL, 2012. For more cases and information on the case presented here, visit: http://en.openei.org/wiki/Impact_of_Utility_Rates_on_PV_Economics_-_Digital_Appendix

dollars divided by PV production in kWh.[175] This study assumes a net metering arrangement where customers are compensated at the retail rate for energy produced by the PV unit, up to 100% of the building's electricity usage.

Overall, the study finds that rates can have a significant effect on the customer value of PV. In particular, NREL observed from the cases it ran across 207 rate structures, 77 locations and 16 commercial building types that location is a significant factor in driving differences in solar value. Furthermore, electricity prices and rates, rather than solar resource characteristics, is what makes location significant. According to NREL, their solar value results varied by a factor of over ten even though solar resources in the United States vary by less than a factor of two.[176]

Furthermore, the study finds that, on average, flat energy-only rates resulted in the highest value for solar. Demand charges with flat rates reduced the value received, as did tiered rates with demand charges. (Demand charges on time of use rates, however, increased solar value compared with energy-only time of use rates).

Figure 5-19 shows results for a hospital building in Phoenix, Arizona and in New York City. The two rates without demand charges, SC2-I and SC2-II fare the best, with the time of use rate (SC2-II) improving in value as the size of PV increases. In Arizona, the flat energy rate (SOLAR-3) has more value with greater PV penetration though it is initially negative at lower PV sizes, where the standard flat energy and demand charge (E-32 L) succeeds. These results reflect another finding from the study – flat rates, often with higher energy charges, must have sufficient displaced production from PV to make switching to that rate cost-effective.

175 The study looks at bill savings and PV production, and does not explore impacts on system cost and financing in the analysis.

176 NREL, 2012

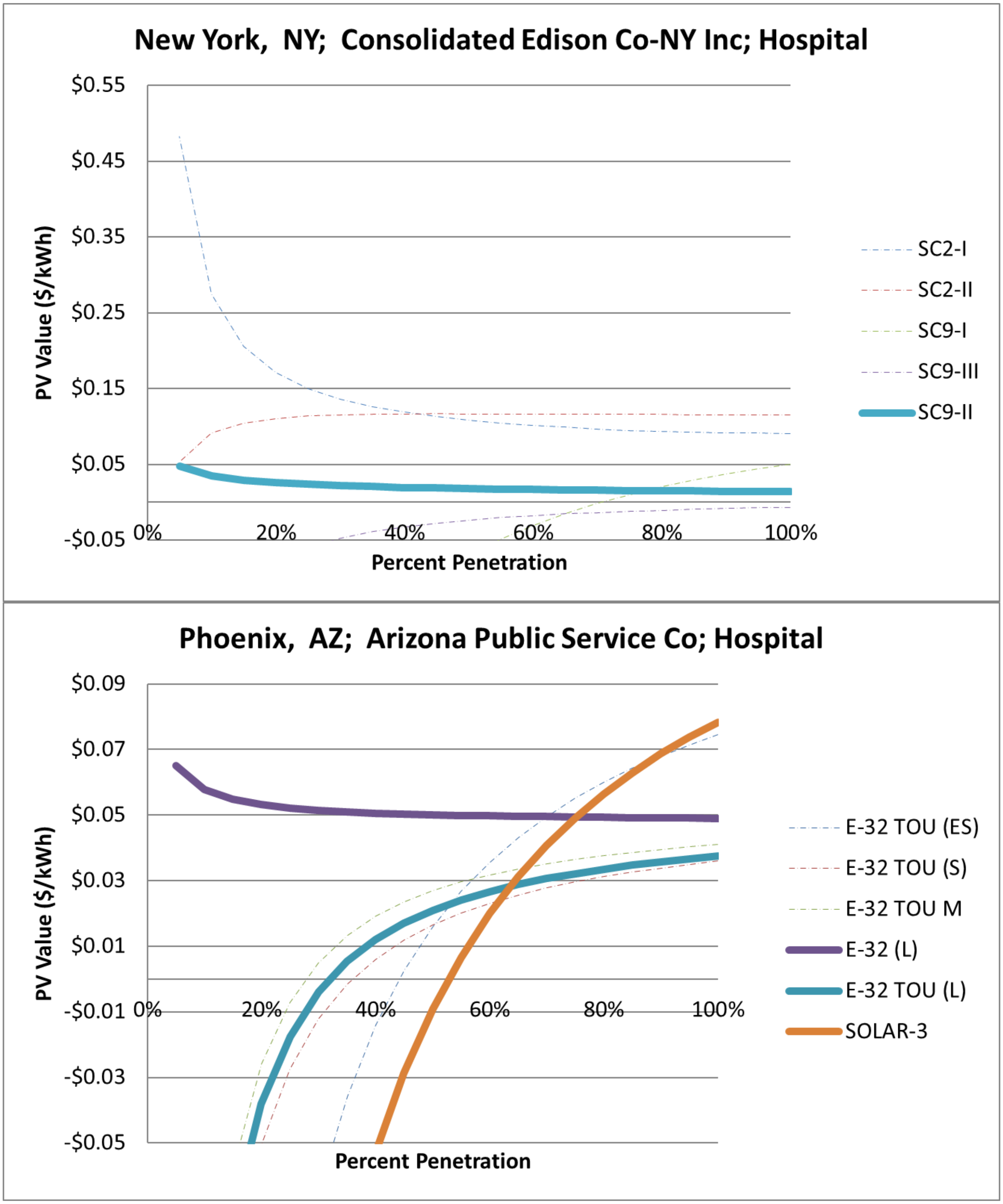

Figure 5-19. Variation in Value of PV by Tariff and Location for Two Sample Cases

Source: NREL 2012

Figure 5-20 depicts the rate structures for those rates evaluated in Figure 5-19.

Utility	Rate	Flat Seasonal	Demand	TOU	Tiered	Average Price	Average Solar Value	Applicability (kW)
Arizona Public Service Co	E-32 TOU (ES)			✓				0-20
	E-32 TOU (S)		✓	✓		$0.116	$0.101	21-100
	E-32 TOU M		✓	✓		$0.124	$0.106	101-400
	E-32 (L)	✓	✓			$0.086	$0.079	400 and Up
	E-32 TOU (L)		✓	✓		$0.102	$0.040	400 and Up
	SOLAR-3	✓				$0.158	$0.115	0 and Up
Consolidated Edison Co-NY Inc	SC2-I				✓			0-10
	SC2-II			✓				0-10
	SC9-I	✓	✓			$0.238	$0.107	10-1,500
	SC9-III	✓	✓			$0.163	$0.092	10-1,500
	SC9-II	✓	✓			$0.089	$0.054	1,500 and Up

Figure 5-20. Evaluated Rates with PV

Source: NREL 2012 (Digital Appendix)

5.4.2 Energy Storage and Photovoltaic Solar

DNV GL developed a case study to illustrate potential cost-effectiveness of a PV-storage combination serving the primary function of electricity bill management. In particular, this scenario has storage and PV servicing a common area within a multi-family residence building, which has a sizeable share of the total building peak load. The main functionalities of storage include peak shaving, energy, and solar PV time arbitrage. DNV GL used its software, the Microgrid Optimizer (MGO), to estimate optimal dispatch of storage for maximizing revenue.

Figure 5-21 and Figure 5-22 summarize case input assumptions. Three levels of installed cost of storage are tested in this case study. Incentives considered for this case study include direct rebates on PV and storage investments, income tax credits, and Modified Accelerated Cost Recovery System (MACRS).[177]

Parameter	Unit	Value
Peak demand (2013)	kW	22.5
Capacity factor of PV (without derating or losses)	%	23.92%
Storage technology	—	High energy Li-Ion
Rated power	KW	5
Discharge duration at rated power	hours	2
Round trip storage efficiency	%	87.0%
Installed capacity of PV	kW	50

Figure 5-21. PV and Storage Case Unit Characteristic Assumptions

[177] Direct rebate is considered as taxable income on the first year, and the calculations for Internal Rate of Return (IRR) are done with and without direct tax rebate. Income tax benefit is calculated as a tax credit based on the total capital cost, applied to first year only. The new accelerated cost recovery system which is only applicable to renewable generation assets, allows for greater accelerated depreciation over longer time periods. In this case study, MACRS is calculated based on accelerated depreciation term of 5 years applied only to solar investment over 5 years. It is applied to the total capital cost.

Parameter	Unit	Value
Installed cost of storage	2013 $/KW	3, 000 to 4,500
Storage system O&M cost	2013 $/KW	$20
Installed cost of PV	2013 $/KW	$5,440
PV O&M cost	2013 $/KW	25
Cost of debt	%	7.49%
Federal income tax rate	%	35%
Direct rebate on storage	2013 $/KW	1800
Direct rebate on solar PV	2013 $/KW	350
Accelerated depreciation term for storage	years	5
Accelerated depreciation term for solar PV	years	5
Income tax rebate on solar PV	%	30%
Income tax rebate on storage	%	22.50%

Figure 5-22. PV and Storage Case Unit Cost and Incentive Assumptions

The tariff simulated represents a time of use tariff in the San Diego Gas and Electric territory (SDGE AL-TOU) which includes energy rates that vary by time of day and season, and includes demand charges.

Figure 5-23 summarizes the results for scenarios of various battery technology costs with and without incentives. It is shown that in this configuration, only cases with low and medium storage costs that benefit from the incentive credits have a net present value (NPV) of greater than zero and are cost-effective. Internal rate of return (IRR) drops significantly for the cases without incentives.

Scenario Characteristics				Installation			Incentives					Financial Results	
Configuration	Customer type	Primary function	Storage cost	Facility peak demand	Installed storage	Installed PV	SGIP	CSI	FITC PV	FITC Storage	Acc dep	IRR	NPV
Storage and Solar PV dc-coupled	Common area meter of multi-family residence	Demand and energy charge reduction	Low - $3000/KW	22.5	5 KW, 10 KWhr	5 KW	YES	YES	YES	YES	YES	13.12%	$4,277
			Med - $3500/KW									10.24%	$2,340
			High - $4500/KW									5.99%	($1,535)
			Low - $3000/KW				NO	NO	YES	YES	YES	4.97%	($2,710)
			Med - $3500/KW									3.47%	($4,648)
			High - $4500/KW									1.01%	($8,523)

Figure 5-23. Sample Results Summary for Energy Storage and PV Support of Electricity Bill Management

These results indicate that the role of incentives is significant for investment in this particular DER setting and customer. Cost-effectiveness, in this particular circumstance, requires incentives such as direct rebate and tax credits to help with the capital expenditures. Additional details for this case study are provided in the Appendix.

5.4.3 Energy Storage and Market Participation

DNV GL also developed a case study to illustrate potential revenues from energy storage participating in wholesale markets, and to explore the role of incentives on project cost-effectiveness. The scenario uses DNV GL software to estimate optimal bidding patterns for energy, regulation up, regulation down and spinning reserves in the California ISO market.[178] Figure 5-24 outlines assumed battery characteristic in the scenario.

Parameter	Unit	Value
Rated power	kW	1,000
Energy capacity	kWh	3,800
Round trip storage efficiency	%	84.5

Figure 5-24. Case Study Battery Technology Characteristics

To illustrate the impact of wholesale market prices on cost-effectiveness, two scenarios are considered: a Low Price scenario and a High Price scenario.[179] The Low Price scenario uses the same price profile as the High Price scenario, adjusted downwards.[180] Compared to High Price scenario, annual average prices for the Low Price scenario for day-ahead energy, regulation, and spinning reserve are lowered by 27%, 37%, and 79%, respectively. Figure 5-25 outlines the annual average prices for the High Price and Low Price scenarios.

Parameter	Annual Average Price ($/MW)	
	High Price scenario	Low Price scenario
Energy	67.74	49.36
Regulation up	25.65	16.15
Regulation down	13.88	8.74
Spinning reserves	25.54	5.39

Figure 5-25. High Price and Low Price Scenarios

Annual revenues from providing energy and ancillary services with a storage device, and under the High and Low Price scenarios, are shown in Figure 5-26.

[178] Battery degradation is not incorporated as a factor for consideration in the bidding behavior.

[179] DNV GL developed the prices under the High Price scenario as a projection of 2020 prices in the California ISO using PLEXOS modelling of the California ISO system. The projection is not intended to reflect forecasts of California ISO or New York ISO prices as much as reflect potential future time series of market prices.

[180] Average 2012 prices in New York ISO for day-ahead energy, regulation and spinning reserve were used to adjust the High Price scenario data downwards. To calculate 2020 average values, 2012 average prices were escalated with an annual escalation rate of 2% to represent 2020 prices. The prices were also inflated with inflation rate of 2% to reflect prices in 2013 dollars. The High Price scenario hourly prices were then adjusted so that their average would be the 2020 average prices calculated in the previous step.

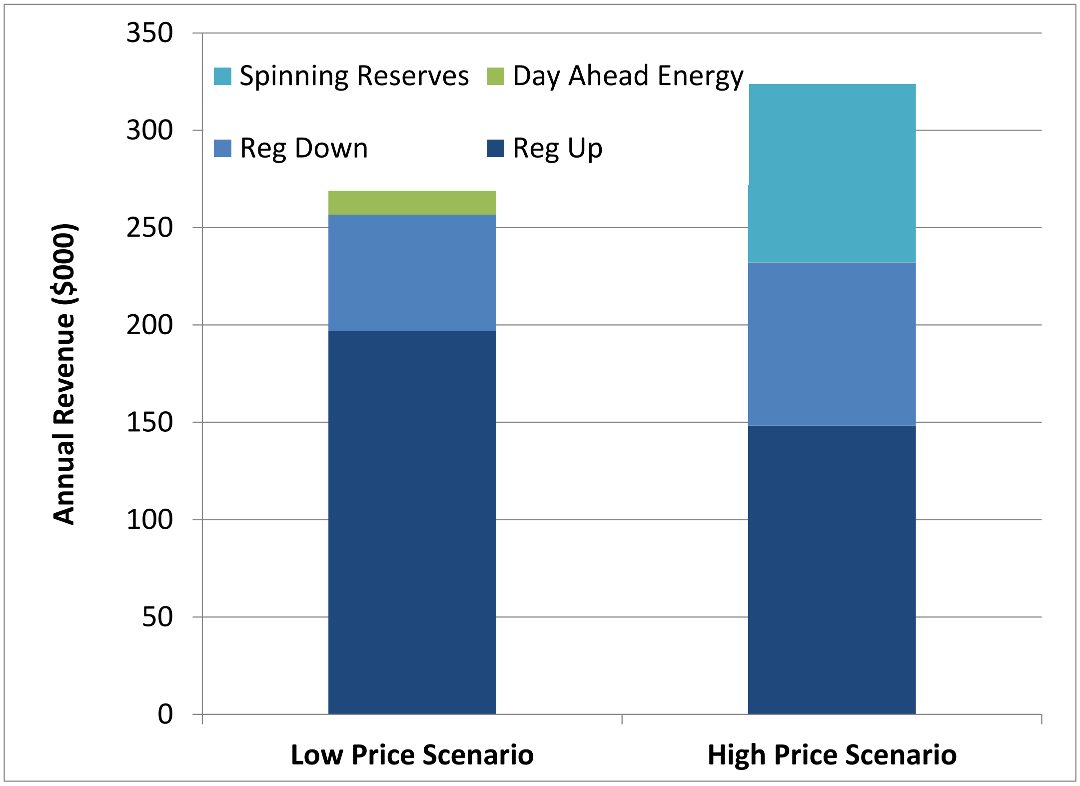

Figure 5-26. Sample Annual Revenue from Energy Storage Participation in the California ISO Markets

Under the High Price Scenario, Regulation Down and Regulation Up constitute the majority of the revenues (46% and 26% respectively), with Spinning Reserves revenue making up the remainder, 28%. Regulation Down and Regulation Up also constitute the majority of the revenue in the Low Price Scenario, at 73% and 22%, respectively. However, Day Ahead Energy revenues constitute the remaining 5% instead of Spinning Reserves.

Figure 5-27 provides a summary of the financial results per price scenario, along with other scenarios that vary storage costs ($3,000/kW to $4,500/kW total installed) and available incentives (with and without direct rebates or income tax credits). In the High Price case, the revenue potential from market participation proves to be cost-effective even under higher estimates of technology cost. In the Low Price scenario, cost-effectiveness is dependent on cost or incentives. Most importantly, the price scenario has a high impact on the cost-effectiveness assessment for energy storage. Reducing the regulation up and down prices by about 37% reduces the internal rate of return by more than 50%.

Scenario Characteristics			Incentives		Financial Results	
Wholesale prices scenario	Storage cost ($/KW)	Installed Storage (KW, KWhr)	Storage Direct Rebate	Income Tax Credit	IRR	NPV
High Price Scenario	Low - $3000/KW	1 MW, 3.8 MWhr	YES	YES	44.84%	$2.506
	Med - $3500/KW				30.26%	$2.118
	High - $4500/KW				17.21%	$1.343
	Low - $3000/KW		NO	YES	17.12%	$1.336
	Med - $3500/KW				13.45%	$0.948
	High - $4500/KW				8.37%	$0.173
	Low - $3000/KW		NO	NO	11.30%	$0.661
	Med - $3500/KW				8.30%	$0.161
	High - $4500/KW				4.04%	($0.839)
Low Price Scenario	Low - $3000/KW	1 MW, 3.8 MWhr	YES	YES	24.28%	$1.173
	Med - $3500/KW				16.06%	$0.785
	High - $4500/KW				7.57%	$0.010
	Low - $3000/KW		NO	YES	7.51%	$0.003
	Med - $3500/KW				4.89%	($0.385)
	High - $4500/KW				1.10%	($1.160)
	Low - $3000/KW		NO	NO	3.31%	($0.672)
	Med - $3500/KW				1.05%	($1.172)
	High - $4500/KW				-2.29%	($2.172)

Figure 5-27. Sample Results Summary for Energy Storage Participation in the California ISO Markets

Ultimately, the scenarios show the importance of future wholesale market prices on unit cost-effectiveness, and reliance on financial incentives or cost reductions without those incentives. Additional details for this case study are provided in the Appendix.

6 TREATMENT OF DERS

6.1 Market and Business Rules and Practices around DER

Under the authority of FERC, ISO/RTOs operate competitive electricity markets.[181] Broadly, these markets deliver energy, ancillary services and capacity to customers within their footprints.[182] Ancillary services serve the function of helping to balance the delivery of electricity supply and demand in real time, while capacity markets help ensure investments are made to ensure adequate supply to serve peak loads. In their role, ISO/RTOs work with their stakeholders to define market and business rules for all market participants, ensuring nondiscriminatory access. In addition to managing markets that deliver services, ISO/RTOs are also responsible for managing the transmission system. Here, ISO/RTOs ensure the reliability of the bulk grid and help plan for expansion regionally. In addition to market rules, rules and processes around interconnection are another means to help ensure successful grid operations and planning.

The following sections provide an overview of market participation opportunities for DERs across different ISO/RTOs, as well as the rules and requirements for that participation. While ISO/RTOs do not have explicit rules for DERs in their markets, existing rules provide the means for participation of both generation and non-generation resources. Such rules currently define the ways in which DERs can integrate with the grid at the wholesale level.

6.1.1 Interconnection and Authorities

The interconnection process, and related technical, contractual, metering, and rate rules is the process by which a generator connects to the grid. Which authorities oversee this process and the manner in which they treat resources depend on:

- **Point of interconnection.** Whether the assets are connecting directly into the transmission grid, the distribution grid or behind the customer meter.
- **Asset size.** What the planned capacity is that will be interconnected.
- **DER application.** Whether the unit produces excess power, and whether and how it plans to interact with the wholesale market.

Generally, procedures for interconnection vary depending on whether resources are on the utility side of the meter or behind the meter.

At the wholesale level, the Federal Energy Regulatory Commission (FERC) set standards for the interconnection process in the Small Generator Interconnection Procedure (SGIP) and Small Generator Interconnection Agreement (SGIA).[183] Such processes are applicable only to assets connecting at the transmission level, participating in the wholesale market (regardless of interconnection location), or selling to a third party over a FERC-jurisdictional portion of the system.

In light of the increasing adoption of small generator resources and the continued focus by states and others on the development of DERs, FERC recently revised the SGIP to "ensure interconnection time and costs for Interconnection Customers and Transmission Providers are just and reasonable and help remedy undue

[181] The exception is ERCOT, which is not under the jurisdiction of FERC.
[182] CAISO does not operate a capacity market as other ISO/RTOs but rather works with entities in California to ensure long-term resource adequacy.
[183] See: http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp

discrimination, while continuing to ensure safety and reliability."[184] The revised SGIP includes, among other things, an adjusted eligibility threshold for the Fast Track process (from 2 MW to 5 MW) and also specifically includes energy storage devices. The *pro forma* SGIP describes the interconnection process and includes three alternative procedures for evaluating an interconnection request, namely:

- the Study Process, which can be used by any generating facility with a capacity no larger than 20 MW;
- the Fast Track Process for certified Small Generating Facilities no larger than 2 MW; and
- the 10 kilowatt (kW) Inverter Process for certified inverter-based Small Generating Facilities no larger than 10 kW.

With regard to energy storage, FERC outlines a general approach to assessing a storage provider's capacity. In particular, FERC recommends that for individual storage assets, transmission providers use the maximum capacity a unit is capable of delivering to decide whether and how to connect under the SGIP process. For assets combined with another resource, FERC recommends that transmission providers consider the capacity as specified on the interconnection request.

At the distribution level, interconnection procedures and standards are typically set by the state public utilities commission (PUC). While most states have state-wide interconnection policies, distribution operators may also have their own interconnection requirements which vary by territory and often depend on unit size. Overall, the interconnection process can involve an array of technical and regulatory requirements of various governing bodies and utilities.

The Standard Interconnection Requirements (SIR) procedures in New York were recently updated (February 2014) by the PSC for a more transparent and swift interconnection process for distributed generation below two MW. A "fast track" application process is available to distributed generation below 50 kW, or below 300 kW for inverter-based generators such as PV, with some exceptions such as underground interconnection. The PSC maintains a list of pre-certified equipment to further facilitate the process. For DERs and equipment not eligible for the expedited application, a Coordinated Electric System Interconnection Review (CESIR) is required for the utility to ensure that certain safety and reliability standards are met, and to identify any upgrades needed to the distribution system. The PSC process for Standard Interconnection Requirements for Small Generators is outlined in Figure 6-1.

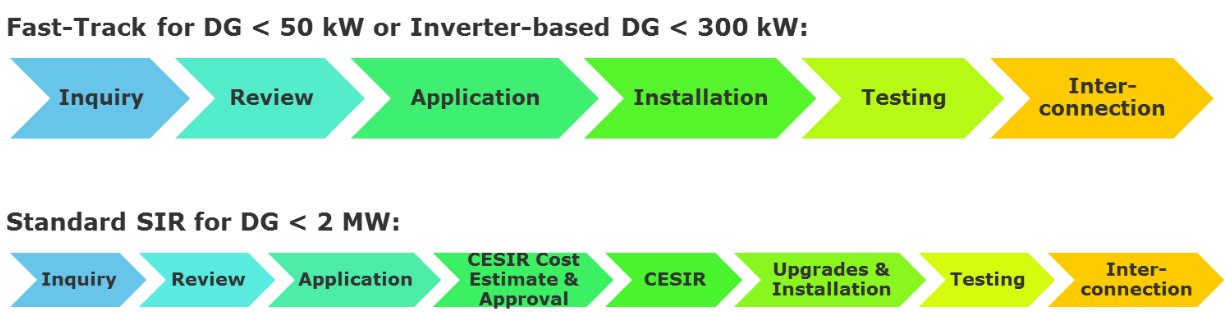

Figure 6-1: New York DG Interconnection Process

Source: NY PSC

[184] See: https://www.ferc.gov/whats-new/comm-meet/2013/112113/E-1.pdf

Interconnection requirements vary greatly across the United States and can effectively facilitate or discourage adoption of DERs. States that allow fast-track application processes for smaller systems, use a standardized agreement, and have few barriers to DG interconnection include:[185]

- Most North-Eastern States (including NY, PA, MA, NJ, ME);
- Several Western States (CA, OR, WA, NV, NM, CO, UT); and
- Many Mid-western States (including IL, IA, OH, IN).

In states where a state-wide interconnection standard is lacking (such as Arizona), or where safety or insurance requirements are rigorous or complex (such as Texas), the process to connect to the grid may be more cumbersome, time consuming, or costly for generation owners.

6.1.2 ISO/RTO Products Relevant to Distributed Energy Resources

Today, ISO/RTOs do not explicitly specify DERs as a resource category in their market rules. Rather, most DERs participate in the markets as either demand response resources, where they modify customer loads, or as production resources that inject power into the grid. Furthermore, rules for treatment of energy storage have also evolved recently. This section outlines demand response and energy storage-related market rules relevant to DERs, including requirements for participation. Rules for production assets are also relevant to DERs operating as generating assets, but are not detailed in this section.

Demand Response

Currently, the majority of behind-the-meter DERs that participate in wholesale markets do so as demand response resources, facilitating load reduction. This includes resources that have the flexibility to increase or decrease consumption in response to an economic and/or a reliability signal received from the system operator. Some of these resources use back-up generation to provide the service, switching their power supply from the grid to the distributed generation resource during demand response events. In those situations, there are various standards and rules across the regions on how to account for the production of the distributed generation resource, and how to calculate the baseline for performance and compensation analysis.

There are numerous ways in which dispatchable demand response can operate in a market; from responding to dispatch signals and being eligible to set the energy clearing price, to being a voluntary response resource, and taking the energy price in the market, to being a capacity or emergency resources only. Most ISO/RTOs have wholesale markets for Energy, Ancillary Services, and Capacity markets that are open to demand response resources.

Categories of demand response, which reflect their current usage in the ISO/RTO markets and by utilities, are illustrated in Figure 6-2.

[185] http://freeingthegrid.org/wp-content/uploads/2013/11/FTG_2013.pdf

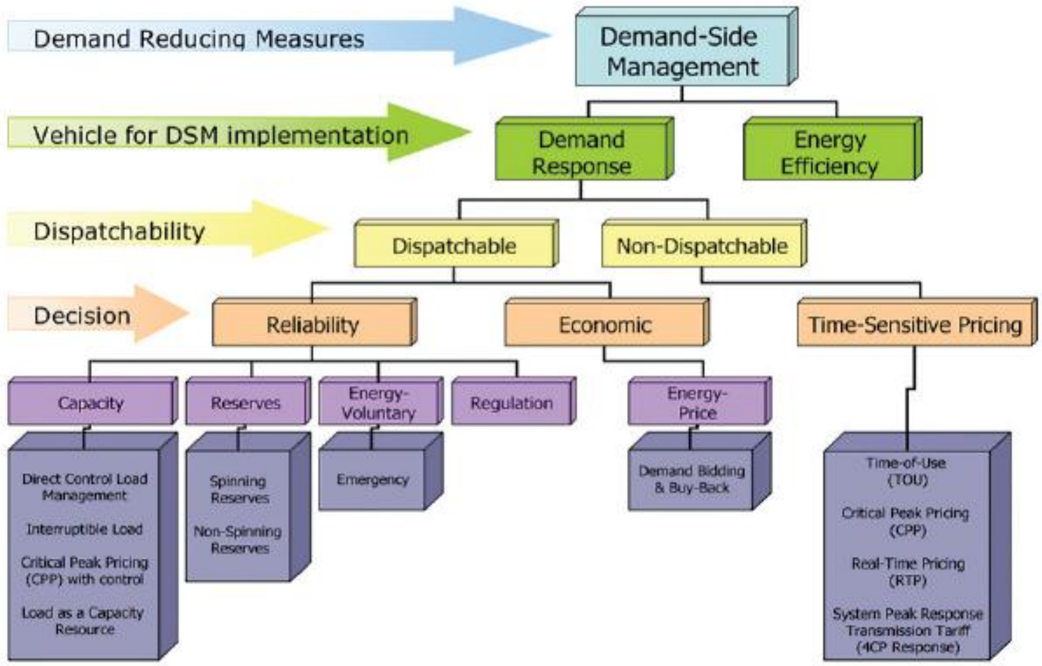

Figure 6-2: Demand Side Mangement Product Categories

Source: NERC 2011

Figure 6-3 outlines the wholesale markets in which demand response is eligible to participate. All markets allow demand response to contribute to a capacity or reserve product, and all but ERCOT allow demand response to participate in the energy markets. NYISO, MISO, PJM and ERCOT allow demand response resources to participate in regulation markets. CAISO is currently in the midst of developing their demand response products.[186] ISO-NE is evolving its approach toward integrating demand response into their energy and reserves market, with revisions expected by June of 2017.[187]

186 For more information, see: https://www.caiso.com/1893/1893e350393b0.html

187 For more information, see: http://www.iso-ne.com/key_projects/price_res_dmnd_res_mrkt/index.html

	Name	Advance Notification(s)	Ramp Period	Sustained Response Period	Recovery Period
CAISO	Proxy Demand Resource Product	Day-Ahead = Market Clearing (~ 1:00 PM) / Real-Rime = Resource Start-Time	Based on Resource Parameters	1 hour or resource's min run time	Based on Resource Parameters
	Proxy Demand Resource Product	Day-Ahead = Market Clearing (~ 1:00 PM) / Real-Rime = Resource Start-Time	10 Minutes	2 Hours (Maximum)	Based on Resource Parameters
ERCOT	Emergency Response Service --10 minutes	None	10 Minutes	As Dispatched / Recalled	10 Hours
	Emergency Response Service -- 30 minutes	None	30 Minutes	As Dispatched / Recalled	10 Hours
	ERS-10 or ERS-30 (different type of resource)	None	10 Minutes or 30 Minutes	As Dispatched / Recalled	N / A
	Non-Controllable Load Resources providing Responsive Reserve Service -- Under Frequency Relay	None	10 Minutes (Verbal) 30 Cycles (Relay)	As Dispatched / Recalled	3 Hours
	Controllable Load Resources providing Responsive Reserve Service	None	Continuous primary frequency response, similar to generator governor action; and 10 minutes (1 minute to release capacity to SCED)	As Dispatched / Following SCED Base Points until Recalled	N / A
	Controllable Load Resources providing Non-Spinning Reserve Service	None	30 minutes (20 minutes to release capacity to SCED)	As Dispatched / Following SCED Base Points until Recalled	N / A
	Controllable Load Resources providing Regulation Service	None	Effectively Immediate	Primary Frequency Response Continuous /	N / A
	Controllable Load Resources providing Energy via SCED Dispatch	None	5 minutes	5 minutes	N / A
ISO-NE	Day-Ahead Load Response Program for RTDR	Day-Ahead Market Clearing (~4:00 PM)	Effectively Instantaneous	As Scheduled / Dispatched	Not Monitored
	Day-Ahead Load Response Program for RTPR	Day-Ahead Market Clearing (~4:00 PM)	Effectively Instantaneous	As Scheduled / Dispatched	Not Monitored
	Real Time Price Response Program	None	Effectively Instantaneous	As Scheduled / Dispatched	Not Monitored
	Real Time Demand Response Resource	30 minute notification	30 Minutes	As Scheduled / Dispatched	Not Monitored
	FCM: On-Peak Demand Resources	Performance hours defined in Market Rule, known months or years in advance	Effectively Instantaneous	Summer: hours ending 14:00 to 17:00 Winter hours ending 18:00 to	Not Monitored
	FCM: Seasonal Peak Demand Resources	None	Effectively Instantaneous	As triggered	Not Monitored
	Real Time Emergency Generation Resource	30 minute notification	30 Minutes	As Scheduled / Dispatched	Not Monitored
	Dispatchable Asset Related Demand	None	Ramp rate included in energy offer	As Scheduled / Dispatched	As Scheduled / Dispatched
	Transitional Price Responsive Demand	Day-Ahead Market Clearing (~1:30 PM)	None	As Scheduled	Not Monitored
MISO	Demand Response Resource Type I (Energy)	Day-Ahead Clearing (~4:00)	5 Minutes	As Scheduled / Dispatched with 1 Hour (Minimum)	Not Monitored
	Demand Response Resource Type-I (Reserve)	Day-Ahead Clearing (~4:00)	10 Minutes	As Scheduled / Dispatched with 1 Hour (Minimum)	Not Monitored
	Demand Response Resource Type II (Energy)	Day-Ahead Clearing (~4:00)	5 Minutes	As Scheduled / Dispatched with 1 Hour (Minimum)	Not Monitored
	Demand Response Resource Type-II (Reserve)	Day-Ahead Clearing (~4:00)	10 Minutes	As Scheduled / Dispatched with 1 Hour (Minimum)	Not Monitored
	Demand Response Resource Type-II (Regulation)	Day-Ahead Clearing (~4:00)	Effectively Instantaneous	As Scheduled / Dispatched with 1 Hour (Minimum)	N / A
	Emergency Demand Response	None	Resource-Specific (Biddable Parameter)	As Scheduled / Dispatched	Not Monitored
	Load Modifying Resource	None	Resource-Specific (Biddable Parameter)	As Scheduled / Dispatched with 4 Hours (Minimum)	Not Monitored
NYISO	Day-Ahead Demand Response Program	Day-Ahead by 11 am	-	As Scheduled	Not Monitored
	Demand Side Ancillary Services Program	Day-Ahead by 11 am Real-time: 75 minutes	10 Minutes	As Scheduled / Dispatched	Not Monitored
	Demand Side Ancillary Services Program	Day-Ahead by 11 am Real-time: 75 minutes	-30 minutes	As Scheduled / Dispatched	Not Monitored
	Demand Side Ancillary Services Program	Day-Ahead by 11 am Real-time: 5 minutes	Effectively Instantaneous	As Scheduled / Dispatched	N / A
	Emergency Demand Response Program	Day-ahead advisory Day- of: 120 minutes	2 Hours	4 Hours (Minimum)	Not Monitored
	Installed Capacity Special Case Resources (Capacity Component)	Day-ahead advisory Day- of: 120 minutes	2 Hours	4 Hours (Minimum) [or 1 Hour for Test]	Not Monitored
PJM	Economic Load Response (Energy)	Day-Ahead Clears 4pm prior to operating day, RT dispatch up to 2 hours	Resource Specific	As Scheduled / Dispatched	N / A
	Economic Load Response (Synchronized reserves)	real time	10 Minutes	As Scheduled / Dispatched	N / A
	Economic Load Response (Day ahead scheduling reserve)	up to 2 hours	30 Minutes	As Scheduled / Dispatched	N / A
	Economic Load Response (Regulation)	None	Effectively Instantaneous	As Scheduled / Dispatched	N / A
	Emergency Load Response - Energy Only	2 Hours (Maximum)	1 Hour or 2 Hours (Participant Selected)	As Scheduled / Dispatched	N / A
	Full Emergency Load Response (Limited DR - Capacity Component)	2 Hours (Maximum)	1 Hour or 2 Hours (Participant Selected)	As Scheduled / Dispatched	N / A
	Full Emergency Load Response (Extended Summer DR - Capacity Component)	2 Hours (Maximum)	1 Hour or 2 Hours (Participant Selected)	As Scheduled / Dispatched	N / A
	Full Emergency Load Response (Annual DR - Capacity Component)	2 Hours (Maximum)	1 Hour or 2 Hours (Participant Selected)	As Scheduled / Dispatched	N / A
	Full Emergency Load Response (Energy Component)	2 Hours (Maximum)	1 Hour or 2 Hours (Participant Selected)	As Scheduled / Dispatched	N / A

Energy	Capacity	Reserves	Regulation

Figure 6-3. Demand Response Participation and Requirements for ISO/RTO Markets

Source: IRC 2014

Figure 6-4 depicts the sequence of events once a demand response call is issued. It starts from the advance notifications that are sent out to the resources (or the entities that interact with the ISO/RTO). The deployment period consists of the ramping period in which the resource starts to move to the required set-point, sustained response period in which the resource maintains its commitment level. Finally, the recovery period follows the sustained response, and lasts until the normal operation is resumed.

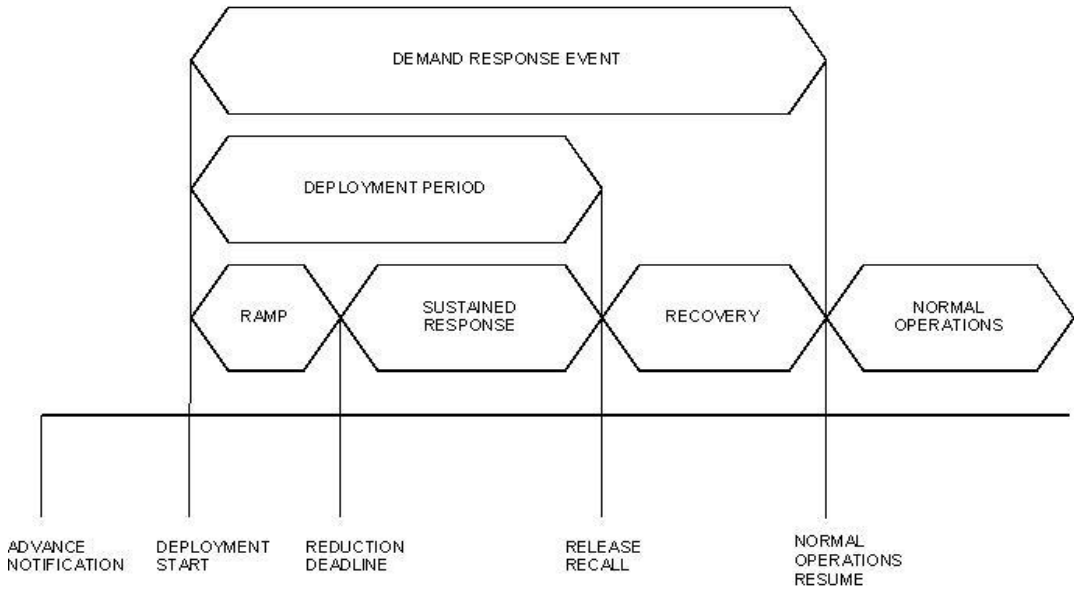

Figure 6-4. Demand Response Events Sequence

Source: LBNL 2013[188]

The requirements for the distinct elements of the events sequence vary across ISO/RTOs and programs:[189]

- **Advance Notification.** How far in advance the resource is notified of a demand response event mostly is aligned with the respective market timescale. Day ahead markets usually consider day-ahead notifications that vary based on the price clearing deadline, and other more frequent markets (such as real-time markets) or emergency programs could have 30-min to up to 2-hour in advance notifications. There are even some programs that do not send out any advance notifications to the resource.
- **Ramp Period.** Most ISO/RTO market products allow for a ramp period for the resource to reach the committed reduction. CAISO's energy market and PJM's Load Response in energy market, for example, determine the ramp period based on resource parameters. Meanwhile, other market products such as ERCOT's regulation and ISO NE's energy market consider immediate ramp periods for the resources. The longest ramp periods are found in NYISO's emergency and SCR programs that have a two-hour ramp period.
- **Sustained Response.** The required duration of response also varies by market product. Shorter resource response times could range around five minutes or less. Longer response times can be seen in many ISO/RTO markets that could last as long as one hour to more than four hours.
- **Recovery.** Most ISO/RTOs do not monitor the recovery period over which the resource returns to its pre-response state. In CAISO, however, this period is determined based on the resource parameters. In ERCOT's capacity market, a 10-hour recovery period is permitted, and a three-hour recovery period is permitted for non-controllable resources in the responsive reserve market.

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188 Adaptation of NAESB, Measurement and Verification Business Practice Standards for Demand Response, 2008. http://emp.lbl.gov/sites/all/files/napdr-measurement-and-verification.pdf

189 IRC 2014

In addition to rules around advanced notification, ramp period, sustained response and recovery, the wholesale markets also define minimum eligible size and minimum reduction amounts. Figure 6-5 identifies the minimum eligible size and reduction for participation in the markets, as well as which ones have telemetry and metering requirements.

	Acronym	Market	Minimum Eligible Size	Minimum Reduction	Metering Requirement	Telemetry Requirement
CAISO	PDR	Energy	100 kW	10 kW	Yes	No, unless over 10 MW
	PDR	Reserve	500 kW	10 kW	Yes	Yes
ERCOT	ERS-10	Capacity	100 kW	100 kW	Yes	No
	ERS-30	Capacity	100 kW	100 kW	Yes	No
	ERS Weather-Sensitive	Capacity	500 kW	500kW	Yes	No
	Load Resource (RRS-UFR)	Reserve	100 kW	100 kW	Yes	Yes
	Load Resource (RRS-CLR)	Reserve	100 kW	100 kW	Yes	Yes
	Load Resource (NSRS-CLR)	Reserve	100 kW	100 kW	Yes	Yes
	CLR (Reg)	Regulation	100 kW	100 kW	Yes	Yes
	CLR - Energy Only	Energy	100 kW	100 kW	Yes	Yes
ISO-NE	DALRP / RTDR	Energy	100 kW	100 kW	Yes	No
	DALRP / RTPR	Energy	100 kW	100 kW	Yes	No
	RTPR	Energy	100 kW	100 kW	Yes	No
	RTDR	Capacity	100 kW	1 kW	Yes	Yes
	OP	Capacity	100 kW	1 kW	Yes	No
	SP	Capacity	100 kW	1 kW	Yes	No
	RTEG	Capacity	100 kW	1 kW	Yes	Yes
	DARD	Reserve	1 MW	1 kW	Yes	Yes
	TPRD	Energy	100 kW	1 kW	Yes	Yes
MISO	DRR-I	Energy	1 MW		Yes	No
	DRR-I	Reserve	1 MW		Yes	No
	DRR-II	Energy	1 MW		Yes	No
	DRR-II	Reserve	1 MW		Yes	No
	DRR-II	Regulation	1 MW		Yes	Yes
	EDR	Energy	100 kW		Yes	No
	LMR	Capacity	100 kW		Yes	No
NYISO	DADRP	Energy	1 MW	1 MW	Yes	No
	DSASP-10	Reserve	1 MW	1 MW	Yes	Yes
	DSASP-30	Reserve	1 MW	1 MW	Yes	Yes
	DSASP-Reg	Regulation	1 MW	1 MW	Yes	Yes
	EDRP	Energy	100 kW	100 kW	Yes	No
	SCR	Capacity + Energy	100 kW	100 kW	Yes	No
PJM	Economic Load Response	Energy	100 kW	100 kW	Yes	No
	Economic Load Response (Synchronized reserves)	Reserve	100 kW	100 kW	Yes	No
	Economic Load Response (Day ahead scheduling reserve)	Reserve	100 kW	100 kW	Yes	No
	Economic Load Response	Regulation	100 kW	100 kW	Yes	Yes
	Emergency Load Response - Energy Only	Energy	100 kW	100 kW	Yes	No
	Full Emergency Load Response (Limited DR)	Capacity	100 kW	100 kW	Yes	No
	Full Emergency Load Response (Extended Summer DR)	Capacity	100 kW	100 kW	Yes	No
	Full Emergency Load Response (Annual DR)	Capacity	100 kW	100 kW	Yes	No
	Full Emergency Load Response	Energy	100 kW	100 kW	Yes	No

Figure 6-5: Minimum Size and Reductions by ISO/RTO Market

Note: This table reflects minimum aggregation amounts though the reductions could be achieved by individual resources of smaller sizes.

Source: IRC 2014

Energy Storage

Energy storage has participated in ISO/RTO markets for a number of years. Rules for participation vary by ISO/RTO. However, many have made modifications to market rules in recent years. Two notable changes include:

- Rule adjustments to include non-generating or limited energy resources; and
- Modifications to payment approaches in ancillary markets based on performance.

The latter modifications were prompted by FERC Order No. 755, issued in October, 2011, which requires that ISO/RTOs develop new rules for compensation of frequency regulation resources based on what is often termed a "pay-for-performance" approach.[190] The approach establishes a two-part payment for resources. The payments are based on the amount of capacity that is set aside to provide regulation service (including the marginal unit's opportunity cost) and on the performance during the provision of the service, or "movement," that reflects the amount of frequency regulation service provided. The approach to implementation has varied slightly across ISO/RTOs.

In terms of rule adjustments to include non-generating or limited energy resources, in 2009, NYISO created a class of resource known as Limited Energy Storage Resources (LESRs), and modified its Automated Generation Control (AGC) software to help maximize the use of this form of storage by managing its "state of charge" to allow it to follow both up and down dispatch. The main benefit of LESRs is the speed of their response to dispatch, not the duration of that response. The "limited" aspect of LESRs reflects the limited amount of time for which they can sustain energy output. LESRs ability to respond rapidly to control signals and continually recharge makes them a valuable resource for Regulation Service. NYISO completed its implementation of pay-for-performance compensation scheme in June of 2013.

CAISO has developed a category of resources known as non-generating resources (NGR). Within the category of NGR are LESRs and dispatchable demand response (DDR). Each has the option to participate in regulation energy management (REM). Here, regulation capacity is evaluated based on what it can serve continuously within 15 minutes. LESR can provide service while charging and while discharging. Like a generator, NGR participating in REM (NGR-REM) must meet 10 minute ramping requirement. NGR-Non-REM resources are subject to the same CAISO requirements as traditional generators. The effect is that limited duration assets, such as some forms of energy storage, have the ability to provide service to regulation markets without necessarily needing 30 to 60 minutes of continuous participation and can be rated at capacity based on a fifteen minute interval. The intent behind this change was to facilitate the participation of dispatchable demand response and energy storage in the wholesale markets.[191] CAISO completed its implementation of pay-for-performance in June 2013.

In 2009, FERC approved tariff changes by MISO which created a Stored Energy Resource (SER) category and a new dispatch method for such resources. This change removed the requirement for the provision of 60 minutes of continuous energy, and helped to manage unit state of charge on a five minute basis. Such modifications allow for short-duration (non-energy assets) storage assets to successfully offer regulation services into the market. MISO completed its implementation of pay-for-performance in December of 2012.

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[191] California ISO, Non-Generator Resource – Regulation Energy Management Implementation Plan Second Edition, March 2012.

PJM also created new rules relevant to storage, creating a separate signal for fast-response resources such as storage and enabling limited energy resources to participate in the market. PJM completed its implementation of pay-for-performance in October of 2012.

The rules for energy storage participation in the ERCOT market are evolving. In 2011, the Texas Legislature enacted storage legislation that classified energy storage as generation assets which entitles them to interconnect, obtain transmission service and sell electricity in the wholesale markets.[192] It also requires owners to register resources with the PUCT, unless registered with FERC. Currently, an ERCOT Energy Storage Working Group is finalizing a Nodal Protocol Revision Request that will develop a definition of an Energy Storage Resource and specify the values needed ("caps and floors used in the mitigation and make-whole calculation processes") for market integration as required by other generation resources.[193] Recently, ERCOT has been piloting energy storage as a Fast-Responding Regulation Service (FRRS). FRRS is a form of Regulation Service that requires resources to respond within a set number of cycles of an instruction or triggering event.[194] Discussions about the formalization of these rules are still underway.[195] Additional relevant decisions in recent years include the determination by the PUCT that wholesale storage is exempt from transmission service rates. In addition, the energy used to charge storage devices is to be bought at wholesale rates, though auxiliary energy consumed in support of the storage asset is to be purchased at retail rates.[196]

Rules for ISO-NE are under evaluation as FERC has required further modifications to ISO-NE proposals to date.[197] ISO-NE has plans to finalize its implementation of pay-for-performance by October of 2014.[198]

6.1.3 Precedence for Application of DERs in the Markets

In many markets DER assets must elect to operate as a demand response resource, a production resource or storage resource. The following highlight rules on DER participation in the markets. In general, generators must comply with the U.S. EPA's Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (RICE) rules as well as local rules, such as applicable DEC rules in New York State. In addition, ISO/RTOs have established processes through which conventional resources must go to enrol. These processes are designed to share information with the ISO/RTOs to enable ISO/RTOs to incorporate these resources into their planning frameworks and to confirm interconnection agreements, telemetry and metering among other agreements

NYISO

In NYISO, there are certain restrictions on the use of on-site generation for reliability programs, such as the ICAP/SCR program. A Local generator that is normally operating to partially serve its Load may participate in the program with incremental capacity that is available to operate at the direction of the NYISO in order to reduce the remaining Load being supplied from the transmission or distribution system. Any incremental capacity in excess of the total host load is not eligible to sell into the NYISO markets. However, excess energy may be eligible to be sold to the local distribution utility through a retail tariff. The resource with a

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[192] TEX. UTIL. CODE. ANN. §§ 35.151 – 152 (Vernon 1998 & Supp. 2011) (PURA)

[193] For more information, see: http://www.ercot.com/mktrules/issues/nprr/551-575/560/index#background

[194] For more information, see: http://www.ercot.com/mktrules/pilots/frrs/index

[195] For more information, see: "Consolidated Working Document (5-6-14)", ERCOT Primary Frequency Response , Working Document – 5-6-14

[196] See Sandia 2013 and http://www.puc.texas.gov/agency/about/commissioners/anderson/pp/Infocast_Storageweek_040313.pdf

[197] For more information, see: http://energystorage.org/system/files/resources/esa_motion_4_10_14.pdf

[198] For more information, see: http://www.iso-ne.com/regulatory/ferc/filings/2014/feb/er12-1643-___-2-3-14_qtrly_reg_mrkt_progress_rpt.pdf

local generator should have an integrated hourly meter that is either installed to measure the output of the generator or interval metering of the total net load.

PJM

PJM does not distinguish between demand response with and without distributed generation, nor does it offer credit for demand response for any excess injection beyond the meter load (i.e., no credit is provided to a resource when it is not acting as a load reducing resource).[199] Though measurement and verification for demand response resources backed up by distributed generation is different than resources without distributed generation, the market rules regarding participation of such resources is no different.

Participation in the capacity market is defined by peak load contribution. Capacity tags for retail customers, based on summer usage coincident with PJM's peak, determine how much capacity customers can offer into the market. For customers with distributed generation, the capacity tag is influenced by operation of the unit during the measurement period of the previous summer. Therefore, offerings to the market would need to be in excess of the load as modified by any DER active behind the meter when the capacity tag was determined. The determination of this capacity tag is the responsibility of the associated distribution operator and not PJM.

ERCOT

Like many ISO/RTOs, ERCOT does not define DER as its own category. Types of resources that participate in ERCOT's markets include: Generation resources that are transmission connected, and load resources that are connected at distribution voltage. Load resources must be registered with ERCOT to participate in the market and their interconnection is handled by the transmission/distribution company. Some load resources provide demand response with the support of back-up generation. Load resources are eligible to provide ancillary services if they are registered and pass the qualification test. The majority of load resources providing ancillary services provide responsive reserves. ERCOT does not have any specific requirements regarding the treatment of back-up generation behind the meter of load resources.

Distributed generation (DG) is a defined category of resource in ERCOT which consists of resources below 10 MW and that are connected at distribution voltage. ERCOT allows the direct participation of DG in several markets. DG interconnection agreements are set up with the service provider (transmission and distribution company) and DG resources are required to be registered and represented by a qualified scheduling entity (QSE) to participate in the market. Resources above 10 MW are connected at the transmission level and participate as a generation resource for which separate rules and requirements apply. As DG not registered as a generation resource appears as an offset in load, it gets paid as a load resource. Load resources in ERCOT are paid at the load zone locational marginal price rather than the nodal price. The settlement is the same as loads on the load weighted average basis across the load zone.

CAISO

DERs can participate in the CAISO markets in three ways: as a conventional resource; as a NGR (see Section 6.1.2); or as a proxy demand resource (PDR). PDRs are effectively demand response resources that shed load in response to the ISOs direction. Conventional resources or NGR must go through the New Resource Implementation Process (NRI) to enroll.[200] For PDR resources that are less than 10 MW in size or

[199] PJM Manual 14D, Appendix A: Behind the Meter Generation Business Rules. For more information, see: http://www.pjm.com/~/media/documents/manuals/m14d.ashx

[200] http://www.caiso.com/Documents/OlivineReport_DistributedEnergyResourceChallenges_Barriers.pdf

that do not have telemetry requirements (such as would ancillary service resources), the process is much simpler. These resources are generally not modeled by the CAISO and metering, rather than telemetry, is often sufficient for CAISO purposes. (Section 6.2 and Section 6.3 describe metering and telemetry requirements for demand response in CAISO's markets).

6.1.4 Challenges for Application of DERs in Electric Markets

As the grid evolved around centralized generation, adjustments to the current framework for power supply dispatch and delivery may be necessary to realize the potential benefits of increased DER penetration and use. The following sections highlight some issues around DER integration which likely need further consideration.

Variability

As observed in Section 3, DERs have the potential to significantly alter load profiles. This, in turn, can lead to increased variability of net load beyond traditional drivers of load variability, such as day type (weekday versus weekend or holiday versus workday), weather, or other major events. DER type and application influence the variability of net load. For example, cloud cover can significantly impact the net production profiles of a customer with PV where no resource exists, such as energy storage or smart inverters, to smooth out the profile.

In addition, without a clear means to predict how DER net load profiles might vary over time, it is feasible that DERs can lead to not only more variability, but also load forecast error. In some cases, variability among resources can be correlated, depending on the application. For example, where storage is applied to PV applications, the resource's charging and discharging profiles would be impacted by variability in the PV profile. In addition, the net resulting variability of a profile can be influenced by multiple drivers at once – an example being where multiple applications of DERs or multiple DER types are used at a given site. Figure 6-6 summarizes causes for variability by resource type.

Resource	Variability Drivers
PV	Solar radiation, atmospheric conditions and PV technology type
CHP	Temperature, conforming load, or prices (where CHP could be applied to price management applications or could be price-responsive)
Distributed storage	PV smoothing requirements (where storage is applied to PV integration applications) or prices (where storage could be applied to wholesale programs or price management applications)
Microgrids or customers with multiple assets	Temperature, conforming load, prices, or PV smoothing requirements

Figure 6-6. Variability Drivers by Resource Type

Source: Derived from DNV GL 2012

The challenge of potentially increased variability from DERs may be exacerbated by the increased variability of centralized supply, such as non-dispatchable wind or solar, and of increased variability of loads. For example, EVs could add variability to load given the potentially large difference between on and off-charging loads, particularly where quick, high power charging is conducted. Commute time and traffic congestion could also add uncertainty to the load profiles. Further research is needed to understand EV load behavior.

Figure 6-7 outlines initial examples of load variability by resource type. These estimates were based on future scenarios of DER adoption in California, using 1-minute PV profiles used in the CAISO LTPP 2020 Environmentally Constrained Case and simulating distributed storage used for PV integration and CHP used for both traditional thermal following operations or also responding to price.[201] While PV has the greatest variability, CHP, distributed storage and microgrids have the potential to increase variability across the one-minute, five-minute and hourly time horizons.

Resource	1 Minute Profile	5 Minute Profile	Hourly Profile
PV	146%	143%	143%
CHP	12%	20%	20%
Distributed storage	18.3%	18.2%	NA
Microgrids or customers with multiple assets	NA	307.7 MW, with min. and max. values of 1,514.4 MW & -417.7 MW	322.8 MW, with min. and max. values of 1,514.4 MW & -417.7 MW

Figure 6-7. Volatility or Standard Deviation/Average

Source: Derived from DNV GL 2012

Ultimately, DERs can increase the dynamics of load, potentially supporting grid needs by providing flexibility. However, the means to predict or react to such variability will be important for successful grid integration. Ultimately, more research is needed to identify the potential for increased load variability due to DERs, and the factors relevant to their variability.

Short-term Forecasting

The unique load shapes that DERs enable, and the added complexity of multiple, new influencing factors can present unique challenges to forecasters. Historically, load has been estimated using historical load data and weather information. Today, load forecast modelling is done with greater sophistication, and forecasts are calculated with greater frequency and in smaller intervals. Furthermore, forecasts for centralized wind and solar have been integrated into system models. However, additional elements may need to be incorporated into load forecasts to successfully predict load with the higher penetration levels of DERs. As with centralized variable energy supply resources such as wind, DERs can have both the underlying variability and uncertainty that contributes to forecast error. More information about net load drivers, the inherent variability in these drivers (such as PV production), and the way in which net load responds to these drivers may help improve load forecasting.

CAISO reported that their load forecasts were being affected by distributed generation, especially distributed solar.[202] Germany also experienced greater day ahead forecast errors, due largely to distributed PV. The problem reached to an extent where in September 2010 grid operators had to activate all of its contracted operating reserves for several hours.[203]

Despite the current challenges associated with DER variability and forecasting, several initiatives could help mitigate the challenges. In particular, increased DER monitoring could potentially reduce forecast error by updating forecast models with current information. Increased monitoring could also provide more information on the underlying drivers of variability in net loads, facilitating predictions of net load.

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201 DNV GL, 2012. For more information, see: http://www.caiso.com/Documents/FinalReport-Assessment-Visibility-ControlOptions-DistributedEnergyResources.pdf

202 GE Energy, 2012. Available online at: http://pjm.com/~/media/committees-groups/task-forces/irtf/postings/pris-task3b-best-practices-from-other-markets-final-report.ashx

203 KEMA 2011. Available online at: http://www.energy.ca.gov/2011publications/CEC-400-2011-011/CEC-400-2011-011.pdf

Furthermore, increased control, or incorporation of DERs into the market, could help reduce variability by allowing ISO/RTOs not only to see the resources, but to actively dispatch them as well.

As a result of Germany's experience with day ahead forecast errors associated with solar PV in 2010, regulators and grid operators implemented improved PV forecasting tools at the transmission and distribution levels.[204] Efforts to reducing forecast error in solar production have been growing in the U.S., however, methods are still being developed and approaches have not developed as fully as for wind forecasting. CAISO has recently taken steps to improve load-forecasting capabilities. Their revised load-forecasting tool incorporates additional input streams, including data on weather forecasts, and conditions such as wind speed, temperature, barometric pressure, and solar irradiance.[205] CAISO is also incorporating renewable forecasts that include behind-the-meter distributed energy resources.[206]

Greater visibility and control ultimately increase the information that the system operator has to work with – allowing operators to prepare flexible resources for addressing aggregate variation in the load profile in a manner similar to approaches for integrating centralized variable supply resources. There are additional challenges around DER visibility and control, however. Some of these are addressed in the metering and telemetry sections (Section 6.2 and 6.3). In addition, there are the challenges of incorporating DERs into the market (whereas all centralized supply resources are required to enroll. Incorporating DER operations into the market directly may ease the ability to forecast behavior, as information about changes in loads would be more readily available. For example, information about the demand response resources that are dispatched by ISO/RTOs can be incorporated back into the real time load forecasts. In addition to facilitating ISO/RTO direct modelling of such resources, and incorporation to dispatch algorithms, market participation means such resources can also get compensated for their contribution.

Greater visibility or control of distributed energy resources ultimately increases the information that the system operator has to work with – allowing operators to prepare flexible resources for addressing aggregate variation in the load profile in a manner similar to approaches for integrating variable supply.

Market Price Dynamics

DERs can significantly modify loads, and with controlled operations, potentially through dispatched commands or financial incentives, they can offer increased flexibility and resilience by expanding the resources available to grid operators. However, increased incorporation of these assets into wholesale electric markets requires careful consideration as their loads may create inadvertent system dynamics if not properly accounted for by system operators.

[204] Ibid.

[205] CAISO and NERC 2013. Available online at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf

[206] Ibid.

Working with the NYISO, DNV GL explored the impact on market dynamics of dispatchable load, price responsive load, and customers who self-optimize against day ahead prices. DNV GL's analysis indicated that imbalances between supply and demand, caused in part by not having complete information about demand, could lead to fluctuations in price, supply, and demand. This behavior occurred where demand was responding to price independently on its own and no feedback was provided to market operators about how demand was behaving, or would likely behave in response to price changes. In particular, imbalances caused by forecast errors could create reactions in price which, in turn, could cause continued fluctuations in price, supply, and demand. As demand becomes more difficult to predict, such as with the presence of self-optimizing customers deploying various DERs, the effect of the fluctuations could be exacerbated.

Demand responding to price, with no feedback or price elasticity information available to market operators, can result in imbalances between supply and demand which in turn can lead to fluctuations in price, supply and demand.

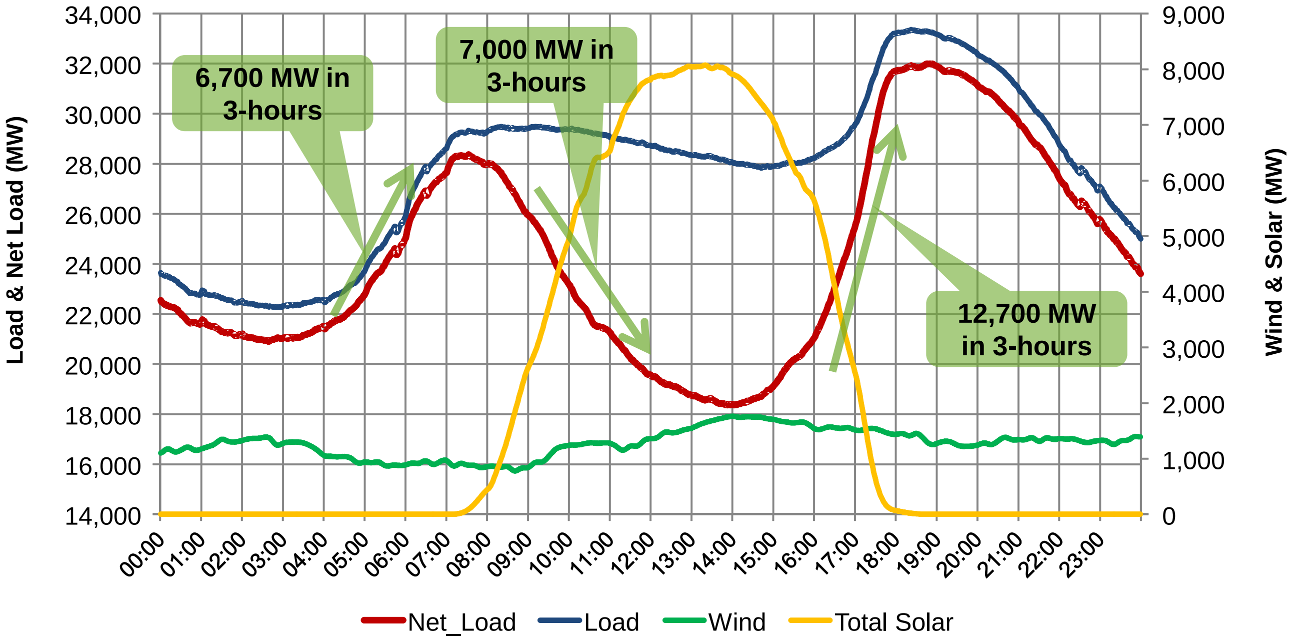
Notably, dispatchable demand response initiated by the grid operator did not create the same dynamics because it was scheduled and known to the grid operator. This emphasizes the potential benefits of "being in the market." Furthermore, the generation portfolio mix influenced the market dynamic outcomes. The elasticities of both supply and demand determined how large imbalances between supply and demand became over time.

The ability to incorporate demand response resources into the market may help limit forecast errors and minimize the creation of price spikes. Alternatively, the ability to estimate price response or have greater visibility of a resource could help reduce market imbalances.

Ramping and Coincidence

DERs have the potential to offset investments in generation, transmission and distribution. However, the coordination of DERs with loads will determine which local or system upgrades or additions can be deferred. In addition, the generation portfolio mix will determine the net effect of aggregate net load reductions. In California, the portfolio mix is projected to consist of a sizeable portion of renewable energy, including wind and solar, of which a sizeable portion is distributed solar. Currently, the capacity of non-dispatchable resources in CAISO ranges from 12,000 MW to 14,000 MW.[207] Going forward, the renewable portfolio standard is targeting the development of renewables such that 33% of load served by utilities will be provided by renewable resources.[208] As a result, the CAISO projects that 3,000 MW of intrahour load following resources will be needed, along with 13,000 MW of continuous ramp-up capability within a 3-hour time period.[209] Figure 6-8 illustrates the expected renewable mix, net load, and flexible resource requirements in CAISO.

[207] NERC, 2013. For more information, see: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf
[208] Ibid.
[209] NERC 2013



Net Load = Load - Wind - Solar

Figure 6-8. Load, Wind, and Solar Profiles: Base Scenario

Source: NERC 2013

In addition to ramping requirements, there is concern for potential periods of over-generation. Figure 6-9 illustrates potential conditions for over-generation, where net load drops below the total production level of non-dispatchable resources on the system. This would occur potentially on days of low demand and high non-dispatchable production.

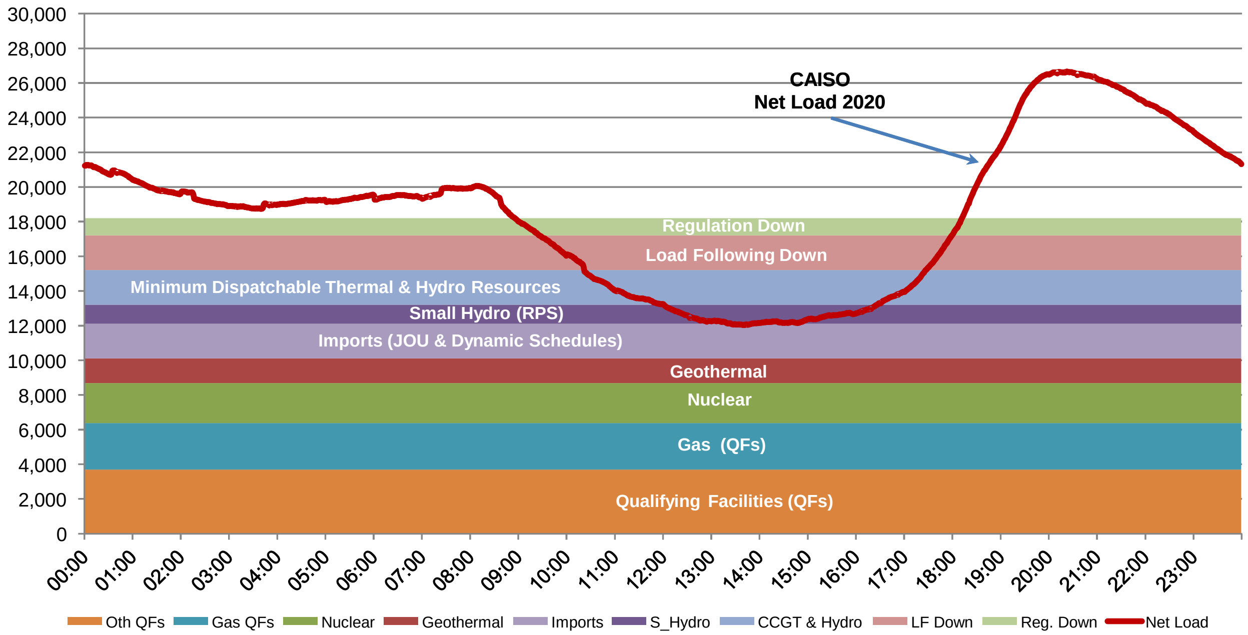


Figure 6-9. Potential Over-Generation Conditions: Base Load Scenario

Source: NERC 2013

The same challenge of over-generation was recently faced by German grid operators. In 2013, wholesale electricity prices dropped negative such that generators were paying grid operators to take their supply. Demand was low and variable energy supply was high – solar and wind power produced more than half of the load. Prices went negative to encourage cutbacks and to protect the grid from becoming unstable. In addition, during 2010, German transmission system operators had to impose curtailments on supply resources almost daily to protect grid reliability.[210]

The extent of variable energy resources (distributed or centralized) in New York may not ultimately match that of California or Germany, but the issue of DER coincidence remains, and should be studied in order to understand the benefits or challenges created by DER on the system.

Ancillary Service Implications

Increased volatility and forecast uncertainty from DERs could result in the need for additional ancillary service resources. Flexible, quick-response resources under ISO/RTO dispatch help meet imbalances caused by deviations from expected conditions (stemming from forecast errors), or help react to planned but rapidly changing system conditions (such as fast-paced upward or downward ramps in non-dispatchable resources). The form of these ancillary services may vary depending on the mix of DERs, mix of centralized generation, and ISO/RTOs preferences regarding approaches to integration.

To date, there has been limited publicly available research done on the potential resource requirement needed under different scenarios of DER adoption (such as scenarios of various DER types, total penetration, and level of integration into the markets) and scenarios of ISO/RTO generation mix. While some studies have been done on the potential for individual DERs to provide ancillary services, few to no studies are available that discuss the ability of DERs to meet ancillary services under aggregated scenarios of DER

[210] KEMA 2011. Available online at: http://www.energy.ca.gov/2011publications/CEC-400-2011-011/CEC-400-2011-011.pdf

adoption or ISO/RTO generation mix. In 2012, DNV GL conducted a study of the impact of DER on load following and regulation requirements under future scenarios of centralized variable generation and DER adoption.[211] The study also explored the role of ISO/RTO visibility into the resources on system load following and regulation needs. Figure 6-10 provides a sample of this study's results. Numbers represent MWs of required load following and regulation, attributed to different types of DER. Additional detail on the methodology and scenarios analyzed is available in the report. However, the results underscore two important findings:

1. DER types contribute differently to ancillary resource requirements, due to differences in their variability and impact on forecast uncertainty. These, in turn, can depend on their applications and the specific DER technologies themselves

2. Increased visibility of DERs by ISO/RTOs could potentially help mitigate ancillary resource requirements

Profile	Load Following Down		Load Following Up		Regulation Up		Regulation Down	
	Visibility	No Visibility	Visibility	No Visibility	Visibility	No Visibility	Visibility	No Visibility
All DER	4753	5683	4652	5079	749	760	1083	1084
All except PV	4214	4799	4538	4844	549	550	790	791
PV Contribution	539	884	114	235	200	210	293	293
All except Demand Response	4364	5026	4518	5002	749	759	1082	1083
Demand Response Contribution	389	657	134	77	0	1	1	1
All except Distributed Storage	4613	5213	4528	4816	673	673	1040	1040
DES Contribution	140	470	124	263	76	87	43	44
CHP	No Appreciable Differences							
SOC								
PEV								

Figure 6-10. Contribution to California Load Following and Regulation Requirements for each DER Profiles, High DER Penetration Case

Note: DES = distributed energy storage, SOC = self-optimizing customers; PEV = plug-in electric vehicle

Source: DNV GL 2012[212]

[211] DNV GL, 2012. For more information, see: http://www.caiso.com/Documents/FinalReport-Assessment-Visibility-ControlOptions-DistributedEnergyResources.pdf

[212] Available online at: http://www.caiso.com/Documents/FinalReport-Assessment-Visibility-ControlOptions-DistributedEnergyResources.pdf

Indirect Impacts on Energy Prices and Centralized Generation

With enough market penetration, DERs, in conjunction with other centralized renewable supply, can potentially affect wholesale prices and other sources of supply. Figure 6-11 illustrates, for example, how DERs might reduce load or increase supply, altering market clearing prices. The impact of distributed renewables and centralized renewables on other centralized generation is being observed already in Germany. In particular, peak hour prices dropped significantly between 2008 and 2013, with the increment above baseload prices dropping from €14 in 2008 to €3 in the first half of 2013.[213] Furthermore, others estimate a 27% decrease in wholesale power prices overall between 2012 and 2013.[214] Part of the cause for this reduction is the coincidence of wind and solar with demand (affecting peak prices) and the fact that the marginal cost of distributed PV resources is little to zero.[215] The net effect of centralized and distributed renewables has been the reduction in load and the increase in supply with low marginal costs.

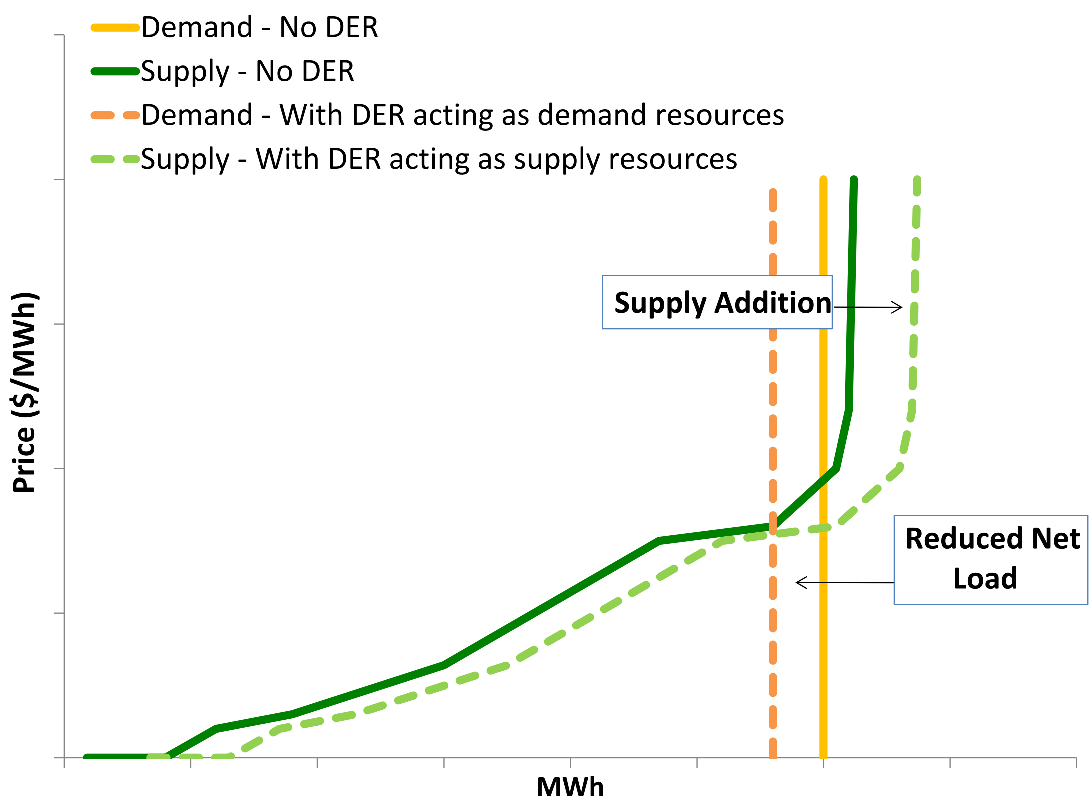


Figure 6-11. Sample Illustration of Increased Supply and Reduced Demand

As a result, revenues that traditional generators relied upon to provide load-following service may no longer be sufficient to maintain operations. Bloomberg New Energy Finance estimated that 30-40% of conventional power stations owned by RWE, a German utility, are losing money.[216] Another German utility, EnBW,

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[213] *How to lose half a trillion euros: Europe's electricity providers face an existential threat*. The Economist, Oct 12th 2013. Available online at: http://www.economist.com/news/briefing/21587782-europes-electricity-providers-face-existential-threat-how-lose-half-trillion-euros

[214] Energy Innovation, "Tale of Two Cities," Viewed 2014.Available online at: http://energyinnovation.org/wp-content/uploads/2013/09/Reflections-on-Germanys-Energy-Transition.pdf

[215] While German markets prioritize wind generation over other resources, it is likely that such resources would be dispatched in priority anyway given their low marginal costs of production.

[216] *How to lose half a trillion euros: Europe's electricity providers face an existential threat*. The Economist, Oct 12th 2013. Available online at: http://www.economist.com/news/briefing/21587782-europes-electricity-providers-face-existential-threat-how-lose-half-trillion-euros

estimates that earnings from electricity generation will fall by 80% between 2012 and 2020.[217] While subsidies for PV are driving a lot of the solar adoption in Germany, and while the cost of production from PV is greater than average wholesale prices, estimates are that even without subsidies, PV adoption and its effects on the wholesale market will continue. In particular, because PV production offsets retail rates for customers, customers often look to the retail prices, rather than wholesale prices in deciding on adoption. In effect, distributed PV production is being adopted on a different basis from the wholesale generation resources it is competing against in the market, even where the resources are not actively enrolled in the market with bids. PV production at low cost by customers allows it to 'beat out' other resources in the wholesale market. Recently, in the U.S., Barclays downgraded the electric sector of the U.S. high-grade corporate bond market based on its forecast of long-term challenges to utilities based on solar energy.[218]

While the reduction in wholesale prices is beneficial for wholesale power consumers, there remains the concern over whether the remaining portfolio mix can satisfy the requirements for ancillary services needed to operate the grid reliably.[219] Figure 6-12 illustrates the composition of a sample supply summer curve for New York. Many of the higher-cost assets also tend to be those with greater ramping capability. For example, the average ramp rate of a U.S. combined cycle gas turbine is 15 to 25 megawatts-per-minute while that of a typical coal plant is 3 megawatts-per-minute.[220]

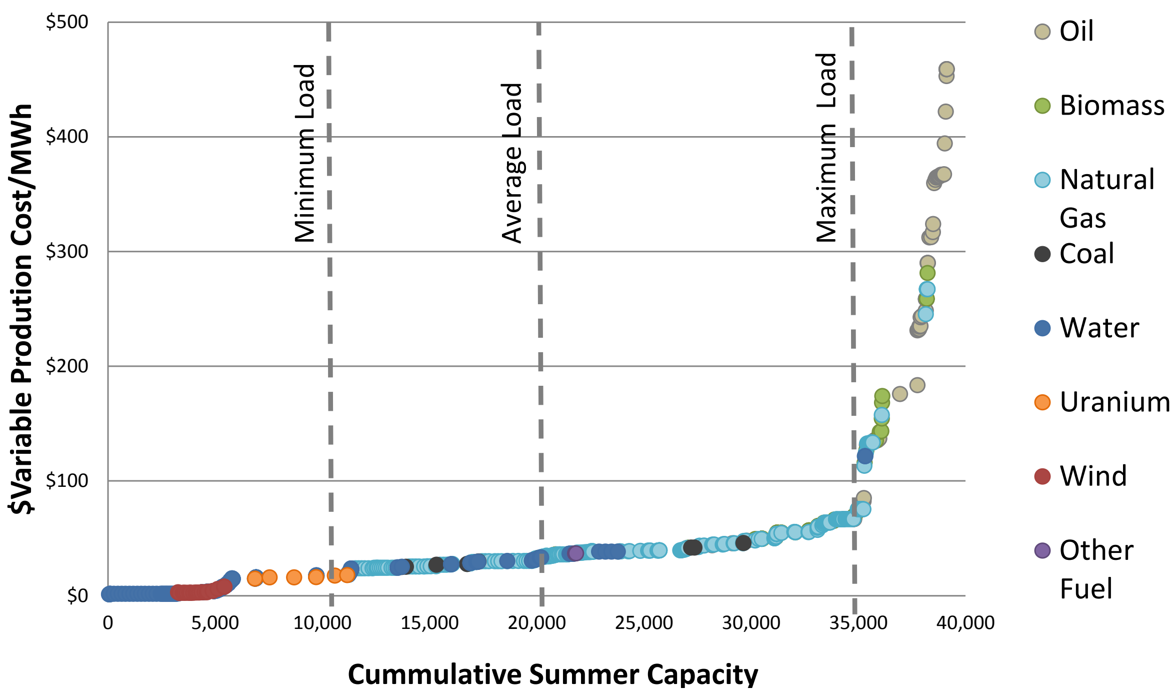

Figure 6-12. Sample Supply Curve by Resource Type

Source: SNL Financial LLC

217 Ibid.

218 For more information, see: http://blogs.barrons.com/incomeinvesting/2014/05/23/barclays-downgrades-electric-utility-bonds-sees-viable-solar-competition/

219 CAISO and NERC 2013. http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf

220 Reflects the average vintage of U.S. coal plants (38 years) than modern coal plants. Available online at: http://www.iea.org/publications/insights/CoalvsGas_FINAL_WEB.pdf

Additional studies are needed to estimate upcoming ancillary needs, under the changing mix of resources and loads, and to estimate the capability of market resources (either demand or supply) in meeting those needs.

Long-term Planning and Capacity

In many markets, demand response resources are successfully being used to provide resource adequacy. For example, PJM has met roughly seven to nine percent of its unforced capacity requirements between 2014 and 2017 with demand response resources.[221] DERs have the potential to support long-term capacity needs through demand response, power production, or both. However, some needs expressed in this area include:

- Greater consideration by transmission providers regarding non-transmission alternatives (NTAs), including demand response, distributed generation, storage, and microgrid deployment, in transmission planning,[222]
- The development of approaches for defining the capacity value of DERs, particularly distributed variable resources,[223] and
- Greater understanding of factors influencing the price sensitivity of demand-side or DER capacity resources, and the potential implications for the availability of such capacity resources over time.

FERC Order No. 1000 requires that transmission providers give consideration to NTAs in their planning processes.[224] However, a 2013 report by RMI identifies potential challenges for cost recovery in this process and the need to develop the capability to evaluate the impact of NTAs.[225]

With regard to the defining the capacity value of DERs, in 2012, the CAISO proposed a new methodology to assign resource adequacy deliverability to distributed generation resources.[226] This methodology would define how load serving entities might count procured distribution-connected generation towards their resource adequacy requirements.

The price-sensitivity of capacity resources is particularly interesting for DERs as these resources are likely to be more transient than centralized assets which have larger, long-term capital expenditures to layout for investment. Furthermore, DER load reductions or production delivered to the grid are often competing with customer interests in serving its own, primary operations. System Operators like the NYISO are required by NERC to plan to serve all loads under normal and post-contingency operations over a long-term (10 year) planning horizon.[227] Transmission elements and large generators have long lives and are generally relied upon for the next ten years, with adjustments for new entrants and retirements that are required to go through structured interconnection or retirement processes. In comparison, DERs are customer-sited and may enter or exit on short notice or no notice. This could create considerable uncertainty regarding

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221 PJM RPM Base Residual Auction Results, Available online at: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/20120518-2015-16-base-residual-auction-report.ashx

222 J. Newcomb, V. Lacy, L. Hansen, and M. Bell with Rocky Mountain Institute, Distributed Energy Resource: Policy Implications of Decentralization, 2013. For more information, see: http://americaspowerplan.com/site/wp-content/uploads/2013/09/APP-DER-PAPER.pdf

223 NERC has issued recommended practices for approaches to defining capacity value for variable resources in 2011. For more information, see: http://www.nerc.com/files/ivgtf1-2.pdf However, while such approaches have been applied to centralized wind resources, entities still are developing approaches to distributed variable energy resources.

224 http://www.raponline.org/document/download/id/6533

225 J. Newcomb, V. Lacy, L. Hansen, and M. Bell with Rocky Mountain Institute, Distributed Energy Resource: Policy Implications of Decentralization, 2013.

226 http://www.caiso.com/informed/Pages/StakeholderProcesses/DeliverabilityforDistributedGeneration.aspx

227 NERC TPL Standards (http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United States)

transmission security and resource adequacy for the bulk system. Assessments on the implication of differences in price sensitivity are needed. For example, greater price sensitivity may mean that such resources are available on relatively short notice in times of intense need. Alternatively the question is whether competing economic forces might result in lower-than-predicted turn out in given years.

6.2 Metering

Any dispatchable resource that directly participates in a wholesale market, regardless of the market structure, must comply with dispatch signals received from the ISO/RTO and must be metered in order to be compensated for the service it is providing. Metering systems can also potentially be used for communications of dispatch instructions as well as for settlement. For demand response resources, a baseline demand is typically calculated to determine the amount of demand response that can be provided in any given hour. Changes in demand are compared to this baseline and measured and verified through a procedure established by the system operator. (Additional discussion on measurement and verification is provided in Section 6.4).

Each ISO/RTO has a set of rules and standards for metering and communication requirements and accuracy for behind-the-meter resources such as load curtailment, load modifiers, and production resources in their respective markets. Most metering requirements include five-minute or 15-minute interval meters, and may require 1-minute granularity for certain products. Telemetry typically ranges from four to six-second real time metering with continuous two-way communication. After-the-fact metering depending on the capacity of the resource and the market in which it is participating is a popular alternative to telemetry. Section 6.3 provides further detail on telemetry.

Resources that do not participate directly in wholesale markets, but are enrolled in programs offered by their local utilities or balancing authorities might be dispatched by those entities. If so, they are subject to metering and communication requirements established by the local providers.

6.2.1 Metering Technologies

Metering Technologies

Metering technologies have evolved significantly over the past decades. Traditional meters, including mechanical and electromechanical meters, are still used today in many regions, but are limited in their ability to provide interval data to utilities. Advanced electric meter technology, including solid-state electronic meters, automatic meter reading (AMR) and advanced metering infrastructure (AMI), are creating the capability to store data in intervals, digitize instantaneous voltage and current and support power factor and reactive power measurements. AMR has allowed for remote readings and AMI has allowed for two-way communications.

Some of the features found with of advanced meters include:

- **Data storage and time-stamp capabilities.** Meters can record and store interval time-series data on energy, demand, and other power metrics, such as voltage, current, etc.
- **Diagnostic capabilities**. The storage of time-series data for additional power metrics can help grid operators monitor system performance and raise flags where values dip below normal ranges (this can be done manually or via algorithms that automatically raise alarms). Such data can also be stored and transmitted for longer-term studies.

- **Two-way communications**. In addition to storing data, many smart meters have the ability for two-way communications, which allows for the dispatch of signals to meters and the transmittal of data from meters.
- **Multiple modes of communication**. most meters have capabilities from traditional phone modem to networked connections and wireless options. In addition, some meters allow for multiple communication options and include an ability to be a communications hub for other devices such as gas or water metering devices.

6.2.2 Communication Architectures and Design Factors

The communication systems behind advanced meters can be configured a number of ways. Common approaches include:

- **Third Party Private Networks.** Private networks owned by a third party. Owners might include, for example, aggregators, merchant generators, or building owner/operators, etc.
- **Utility Distributed Automation Network.** Utilities might also have a private network that is used for multiple applications such as distribution automation applications or other substation communications. Such networks may consist of a combination of owned hardware and wireless technologies
- **Utility Advanced Metering Infrastructure Network.** A network dedicated to AMI is another possibility. These private utility networks might use proprietary or standard wireless technology to communicate with meters for reading, pricing tables, or outage information. Such networks can be used for validation and remuneration purposes for paid demand response resources and for resources that respond to dynamic rates. Utility AMI design is assumed to already have addressed these requirements and the data can be used for model development as well, although the responsibility for that model development between the utility, the ISO, and an aggregator remains an open question. In the event that demand response and dynamic pricing resources are on real time prices the interval resolution and data retention of the utility AMI systems would require validation for this purpose. Two major considerations with this option, are cost and network capacity limitations.
- **Customer Internet.** Communication systems may also leverage systems used by customers. For example, a system might make use of a customer’s wired or wireless internet connection at a DER site provided by public local internet provider. Such a system could be used to carry communications to an end use device, such as a demand response-enabled appliance.
- **Public Carrier**. Systems might use wireless data coverage provided by public carriers such as AT&T, Verizon, or Sprint.
- **Broadcast.** Radio communication is another viable option, particularly where a binary action is called for (such as first-generation HVAC or agricultural demand response programs or hot water heater control programs).

Selection of these options depends on cost constraints and system needs. Common communication systems criteria include:

- coverage (if wireless communications);
- capacity/ delivered bandwidths;
- latencies;
- statistical availability;
- reliability; and
- cost.

For wireless systems, considerations may also include criteria for other measures of resource efficiency, such as available spectrum, spectral efficiency and frequency re-use. For mission or operationally-critical communications, considerations may include criteria for communications or information-security. For example, some common carrier or public network communication systems might be considered for controlling and monitoring DERs, due in part to cost efficiencies and ease of use. However, depending on the applications, such networks might not be acceptable due to security concerns. Communications and information security protection (i.e. device/user authentication, message integrity, and data confidentiality), along with protection against denial of service (DoS), vary widely among the network options. Such security and protection features may be equally important or perhaps more important considerations than criteria of coverage, capacity, and cost alone.

Figure 6-13 illustrates the communications architectures according to their polling time and coverage.

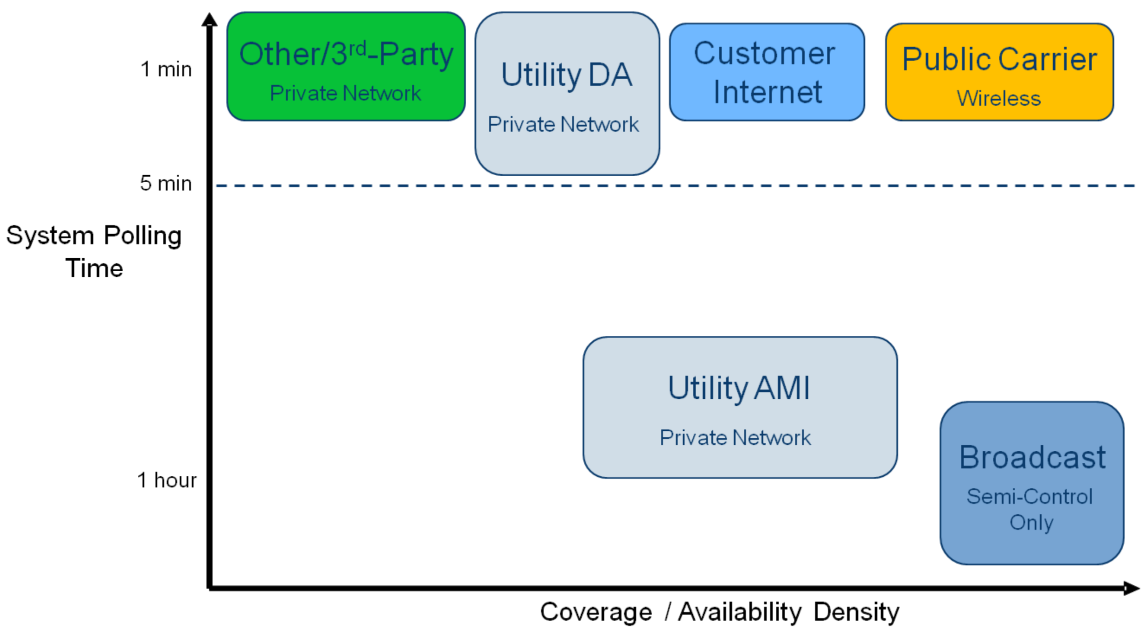

Figure 6-13. Relative Polling Times and Coverage by Communication Architecture

Source: California ISO, DNV GL 2012

In principle, there exists a wide-range of wired and wireless communications options capable of meeting the needs of various DER monitoring and control strategies, and DER deployment/disposition, in both licensed and unlicensed frequency bands using public as well as privately-owned networks. A more complete definition of the services and service requirements that drive the communications needs is necessary to select a communications architecture infrastructure.

For DER supplying grid support and employing advanced control strategies, it is useful to characterize telemetry solutions in terms of operating and control scenarios that drive the communications needs.

For DER supplying grid support and employing advanced control strategies it is perhaps more useful to characterize telemetry solutions in terms of operating and control scenarios that drive the communications needs. Figure 6-14 provides examples of DER application scenarios, estimated communications requirements (including frequency of communications occurrence or latencies and data rates), and suitable communications technologies/solutions. It is one example of how design around applications for DER might shape communications and data requirements.

DER Scenario	Key features & Services	Communications Timescales (occurrence or latencies, data rate)	Suitable technologies/Communications solutions	Notes
Interval Metering, power quality, outage & restoration reporting only	5- or 15-minute interval and power quality data	Metering: Once per 8 or 12 hours; <10kb per reading, <1 kbps; Outage/restoration: <1 kbps	AMI (unlicensed 902-928 Mhz mesh, licensed NB P-MP, WiFi, ZigBee, PLC, cellular) (two-way comms); customer portal or ZigBee SEP 1.1/2.0 /WiFi in-home display	Smart metering w/o DR or DLC
DR	Forward Price signals, real-time CPP events	Minutes/hrs; <1kbps data rate	AMI (unlicensed 902-928 Mhz mesh, licensed NB P-MP, WiFi, ZigBee, PLC, cellular); ZigBee SEP 1.1/2.0 or WiFi to loads/devices (two-way comms)	HVAC (Smart Thermostat), water heaters, washers, refrigerators, VSDs; comms requirements slightly more than above
Direct Load Control	Load control signals	Tens of seconds - minutes; < 1 kbps, often less than 100 bps	FM subcarrier, pager (one-way communications), cellular	HVAC, water heaters
Real/Reactive Power Supply: PV/Wind with or w/o battery storage, IEEE1547/UL 1741 inverters without autonomous voltage regulation, limited ride-through	Generation, Inverter & Battery status, PF setting, ramp, scheduling, disconnect, etc.	seconds – minutes; <10 kbps data rates, 100kb - Mb over several hours	AMI (unlicensed 902-928 Mhz mesh, licensed NB P-MP, cellular); ZigBee SEP 1.1/2.0 or WiFi to loads/devices (two-way comms)	Centralized, Utility monitoring & control of reactive power support, monitoring of real power delivery (net metering), energy generation, battery state/available capacity

DER Scenario	Key features & Services	Communications Timescales (occurrence or latencies, data rate)	Suitable technologies/Communications solutions	Notes
Real/Reactive Power Supply: PV/Wind with or w/o battery storage, Smart Inverter with autonomous voltage regulation, and ride-through	Generation, Inverter & Battery status, PF setting, ramp, scheduling, disconnect, etc.	Minutes - hours; <10 kbps data rates; 100 kb over several hours	AMI (unlicensed 902-928 Mhz mesh, licensed NB P-MP, cellular); ZigBee SEP 1.1/2.0 or WiFi to loads/devices (two-way comms)	Centralized, Utility monitoring of real and reactive power support and real power delivery (net metering), energy generation, battery state/available capacity
Transactive Energy, with Smart inverter and autonomous voltage regulation	Forward and current Price tenders, bids, signals, real-time regulation events, supply and demand forecasts	seconds – minutes; 10s - 100s of kbps data rates, 1 – 10 Mb over 24 hours	Broadband connections (wired or 3G/4G cellular)	Hierarchical; Utility is a party to every transaction
Non-hierarchical Transactive Energy	Forward and current Price tenders, bids, signals, real-time regulation events, supply and demand forecasts	seconds – minutes; 100s - 1000s of kbps data rates, 1 – 10 Mb over 24 hours	Broadband connections (wired or 3G/4G cellular)	Multi-Party transactive;

Figure 6-14. Considered DER Scenarios, Estimated Communications Requirements, and Suitable Communications Technologies/Solutions

6.2.3 Current Meter Usage

The primary use of metering at the utility level is for financial settlements. Utility requirements for metering are varied, and often they are tied to the financial settlements negotiated between customers with DERs and the grid. There are well established precedents for using meter data for financial settlements at the utility level for distributed generation such as CHP and PV, related to net metering, FIT or other special tariffs (see Section 5). In recent years, the advancement of metering technologies has made it possible for utilities to communicate with customers via meters or to collect data on a range of time intervals. In turn, such advancements have allowed utilities to use advanced metering for purposes beyond billing, such as for grid operations. For example, some utilities are looking for advanced metering systems to help manage dynamic conservation voltage reduction controls. These advanced meters are also supporting customer participation in the wholesale markets. Figure 6-15 illustrates the functionalities and applications enabled by advanced meters for utilities. Although this chart is focused more on functionalities and applications for utilities, similar technology trends enable the participation of DER in ISO/RTO markets. The stack starts from the early applications that did not require high frequency data, real-time connections, or two-way capabilities. Most basic mechanical meters which did not have data storage and communication capabilities were still sufficient for such functions. As applications such as price responsive programs or central-dispatch-based participation are considered, real-time communication capabilities become more important. As such, more advanced meters were required to enable interval metering and remote communications. Although electro-mechanical meters could meet hourly metering and daily access requirements with some other auxiliary equipment, their cost with the associated upgrades were prohibitive. Advanced electric meters and smart meter technologies are at the high end of spectrum and provide a high level of accuracy, fine granularity of interval metering, and a means of storing interval data along with one-way and two-way communications using local area network (e.g., radio frequency and power carrier line) and wide area network.

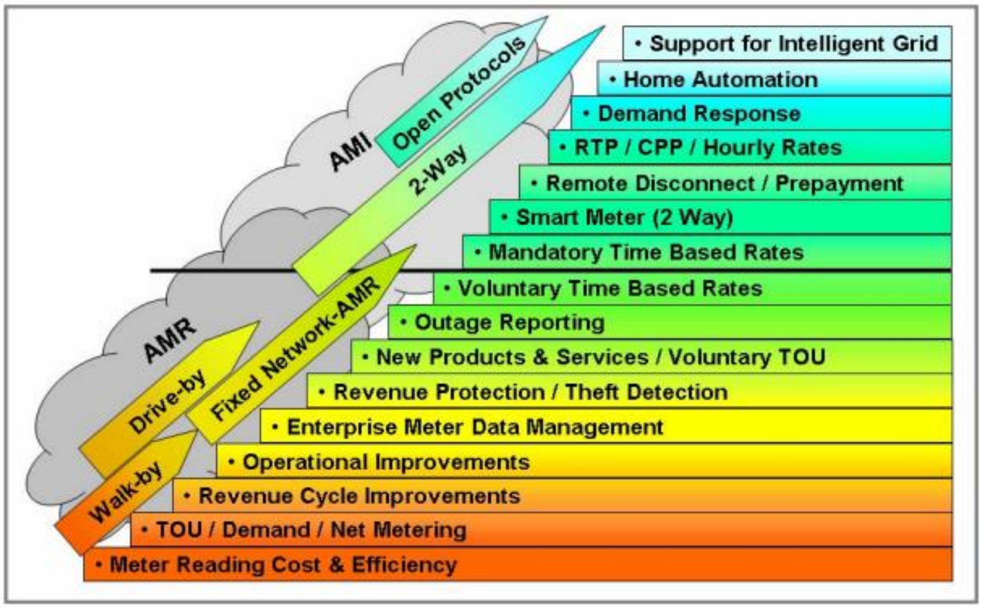

Figure 6-15: AMI Functionality

Note: TOU = time of use, RTP = real time pricing, CPP = critical peak pricing

Source: Itron 2008[228]

The prevalence of smart meters has grown significantly over the past few years. Figure 6-16 illustrates advanced meter deployment between 2010 and 2012 in total numbers and as a percentage of total customer accounts.

[228] Available online at: https://www.itron.com/PublishedContent/Impact%20of%20AMI%20on%20Load%20Research%20and%20Forecasting.pdf

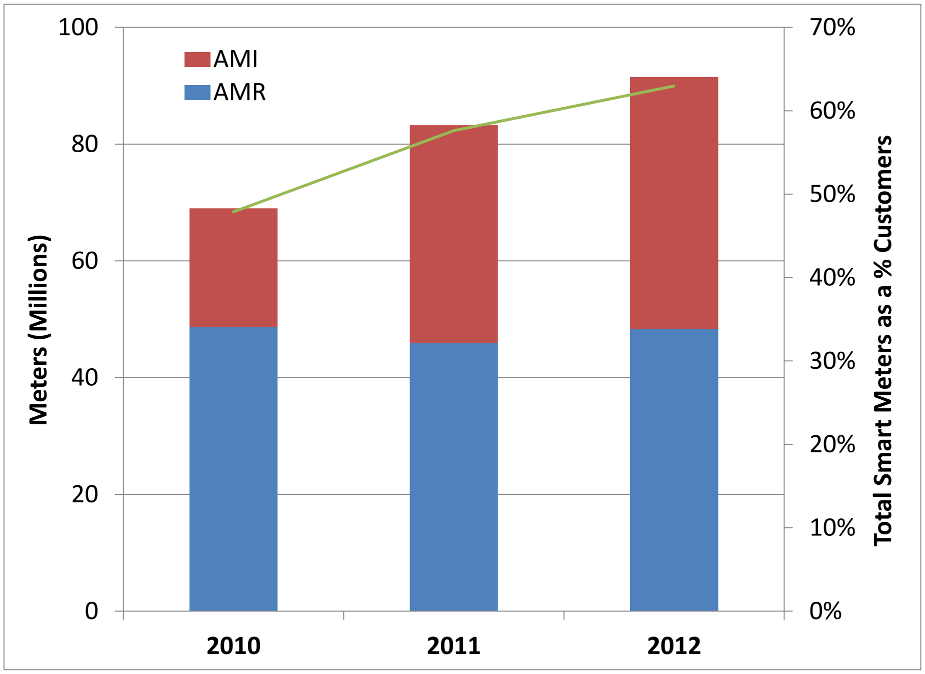

Figure 6-16. Advanced Meter Deployment

Source: Derived from EIA Electric Power Annual 2013

Apart from supporting alternative pricing or tariff schemes or supporting billing functions, grid management opportunities can also be supported by advanced metering. Sample applications include:

- Demand response enrollment, dispatch, measurement and verification and settlement;
- Load forecasting and planning;
- Voltage optimization or conservation voltage reduction;
- Outage management; and
- Asset benchmarking and optimization.

More utilities are contemplating the idea of incorporating this data into their operational and controls procedures. Though not required for implementation of conservation voltage reduction (CVR), many utilities are investigating the use of AMI data for CVR control schemes. Close monitoring of critical voltage points at customer sites can serve as input to control schemes that dynamically adjust voltage reductions, allowing systems to push the limits of their voltage control and maximize savings while maintaining power quality.

Apart from CVR or voltage management schemes, meter data can also help with improving load forecasting algorithms. The critical element with respect to forecasting and load research is the timely collection of interval data. AMI systems enable the capture of interval data for all customers, however, the challenge is to configure them such that they can collect and store interval data on a consistent basis for all customers.

The following benefits load forecasting and load research by using AMI:

- Availability of interval data for all customers: Before AMI, interval data were available for large customers with interval data recorders and for the statistical sample of load research customers. With AMI, interval data will be collected for all customers.
- Data collection on a near real-time basis compared to longer time periods such as daily or monthly
- Continuous process of data collection: Interval data for all customers will be flowing through the data collection system with minimal lag time.

6.2.4 Meter Requirements

Currently, DG uses its distribution meter to net meter. This facilitates the export of power to the grid, though financially it is compensated by a utility as a reduction in the energy demand of the facility. DERs are generally required to have metering that serves both utility and wholesale market purposes where the resources are explicitly being used and enrolled in the markets. However, this is not necessarily the case for generators supporting demand response in some markets. Behind-the-meter generation can be used to support demand response, which can avoid the ISO/RTO metering requirement depending on the ISO/RTO requirements.

6.2.4.1 ISO/RTO Metering Requirements

All wholesale demand response programs require metering, but requirements regarding reporting deadlines, measurement intervals, and allowable accuracies, differ by ISO/RTO and by market product. Current ISO/RTO meter data communication requirements play a strong role in financial settlements of demand response in the markets. Metering data is essential for measurement and verification, which in turn can also support enrollment and planning of demand response resources. The following sections highlight demand response markets across different ISO/RTOs along with their metering requirements. ISO/RTO rules and requirements for programs often change over time. The summaries provided here reflect information provided by the ISO/RTO Council as of February 2014.[229]

New York ISO

Hourly interval metering is required by the NYISO for all demand response programs. Figure 6-17 outlines the metering requirements for demand response resources participating in the New York ISO market. All metering equipment must meet appropriate ANSI C12.1 standards at a minimum.

[229] Available online at: http://www.isorto.org/Documents/Report/20140304_2013NorthAmericanWholesaleElectricityDemandResponseProgramComparison.xlsx

Acronym	Name	Market	Minimum Eligible Size	Minimum Reduction	Metering Requirement	Meter Accuracy	Meter Data Reporting Deadline	Meter Data Reporting Interval
DADRP	Day-Ahead Demand Response Program	Energy	1 MW	1 MW	Yes	+/- 2%	Event Day + 55 Days	1 Hour
DSASP-10	Demand Side Ancillary Services Program	Reserve	1 MW	1 MW	Yes	+/- 2%	Instantaneous, plus Scheduled Day + 55 Days	1 Hour
DSASP-30	Demand Side Ancillary Services Program	Reserve	1 MW	1 MW	Yes	+/- 2%	Instantaneous, plus Scheduled Day + 55 Days	1 Hour
DSASP-Reg	Demand Side Ancillary Services Program	Regulation	1 MW	1 MW	Yes	+/- 2%	Instantaneous, plus Scheduled Day + 55 Days	1 Hour
EDRP	Emergency Demand Response Program	Energy	100 kW (per Zone)	100 kW (per Zone)	Yes	+/- 2%	Event Day + 75 Days	1 Hour
SCR	Installed Capacity Special Case Resources (Capacity Component)	Capacity + Energy	100 kW (per Zone)	100 kW (per Zone)	Yes	+/- 2%	Event Day + 75 Days	1 Hour

Figure 6-17. NYISO Demand Response Markets and Metering Requirements

Note: On May 21, 2014, the NYISO made a compliance filing that would change the metering requirements shown here.[230]
Additional information about telemetry requirements is available in Section 6.3, and in the complete version of the IRC table partially cited here.

Source: IRC 2014[231]

California ISO

Figure 6-18 lists the demand response-related requirements for metering in CAISO's markets. The current CAISO requirements for metering and telemetry stipulate direct telemetry and direct metering by the CAISO of individual resources. These rules, however, may also change. In 2013, the CAISO began a stakeholder process to evaluate the expansion of metering and telemetry options to support emerging business models and to find lower cost alternatives.[232] This effort will focus on alternative architectures that could provide comparable, secure, and reliable data acquisition, communication, and response from dispatchable demand response resources.

[230] See FERC Docket ER14-2006.
[231] A copy of the full IRC table is available online at: http://www.isorto.org/Documents/Report/20140304_2013NorthAmericanWholesaleElectricityDemandResponseProgramComparison.xlsx
[232] For more information se: http://www.caiso.com/informed/Pages/StakeholderProcesses/ExpandingMetering-TelemetryOptions.aspx

Acronym	Name	Market	Minimum Eligible Size	Minimum Reduction	Metering Requirement	Meter Accuracy	Meter Data Reporting Deadline	Meter Data Reporting Interval
PDR	Proxy Demand Resource Product	Energy	100 kW	10 kW	Yes	± .25 %	Event Day +7 Business Days (Estimate) / 43 Calendar Days (Final)	1 Hour for DA / 5 Minutes for RT
PDR	Proxy Demand Resource Product	Reserve	500 kW	10 kW	Yes	± .25 %	Event Day +7 Business Days (Estimate) / 43 Calendar Days (Final)	5 Minutes

Figure 6-18: CAISO Demand Response Markets and Metering Requirements

Source: IRC 2014

ERCOT

Load resources must be registered with ERCOT to participate in the market and their interconnection is handled by the transmission/distribution company; 15-minute interval metering is required for such resources. DG resources in ERCOT are required to have 15-minute interval metering. Figure 6-19 outlines demand response metering requirements in ERCOT.

Acronym	Name	Market	Minimum Eligible Size	Minimum Reduction	Metering Requirement	Meter Accuracy	Meter Data Reporting Deadline	Meter Data Reporting Interval
ERS-10	Emergency Response Service --10 minutes	Capacity	100 kW	100 kW	Yes	± 2 %	Contract Period End + 35 Days	15 Minutes
ERS-30	Emergency Response Service -- 30 minutes	Capacity	100 kW	100 kW	Yes	± 2 %	Contract Period End + 35 Days	15 Minutes
ERS Weather-Sensitive	ERS-10 or ERS-30 (different type of resource)	Capacity	500 kW	500kW	Yes	± 2 %	Contract Period End + 35 Days	15 Minutes
Load Resource (RRS-UFR)	Non-Controllable Load Resources providing Responsive Reserve Service -- Under Frequency Relay Type	Reserve	100 kW	100 kW	Yes	± 2 %	Monthly	15 Minutes
Load Resource (RRS-CLR)	Controllable Load Resources providing Responsive Reserve Service	Reserve	100 kW	100 kW	Yes	± 2 %	Monthly	15 Minutes
Load Resource (NSRS-CLR)	Controllable Load Resources providing Non-Spinning Reserve Service	Reserve	100 kW	100 kW	Yes	± 2 %	Monthly	15 Minutes
CLR (Reg)	Controllable Load Resources providing Regulation Service	Regulation	100 kW	100 kW	Yes	± 2 %	Monthly	15 Minutes
CLR - Energy Only	Controllable Load Resources providing Energy via SCED Dispatch	Energy	100 kW	100 kW	Yes	± 2 %	Monthly	15 Minutes

Figure 6-19: ERCOT Demand Response Markets and Metering Requirements

Source: IRC 2014

ISO New England

As of the publication of this report, ISO New England requires that demand response resources have an interval meter with five minute data reported to ISO-NE, and each behind-the-meter generator is required to have a separate interval meter. For resources serving as Real-Time Demand Response Assets whose demand reductions are not achieved by DG but where there is a generator located behind the retail delivery point, participants must submit a single set of interval meter data representing the metered demand of the end-use facility. The set of data must include the Real-Time Demand Response Asset on the electricity network and a single set of interval meter data representing the combined output of all generation.

For Real-Time Demand Response Assets whose demand reductions are achieved by DG, participants are required to submit a single set of interval meter data representing the metered demand of the end-use facility that includes the Real-Time Demand Response Asset on the electricity network in the New England

Control Area and a single set of interval meter data representing the combined output of Distributed Generation associated with the Real-Time Demand Response Asset.

If a meter used is a distribution meter, ±0.5% accuracy for the meter data is required. Otherwise, the meter must either a revenue-quality meter that is accurate within ± 0.5% or a non-revenue quality meter with an overall accuracy of ± 2.0%. Figure 6-20 outlines the metering requirements for demand response resources in ISO New England.

Acronym	Name	Market	Minimum Eligible Size	Minimum Reduction	Metering Requirement	Meter Accuracy	Meter Data Reporting Deadline	Meter Data Reporting Interval
DALRP / RTDR	Day-Ahead Load Response Program for RTDR	Energy	100 kW	100 kW	Yes	± 2 % (± ½ % if meter is used for Distribution billing)	Monthly	5 Minutes OR 1 Hour
DALRP / RTPR	Day-Ahead Load Response Program for RTPR	Energy	100 kW	100 kW	Yes	± 2 % (± ½ % if meter is used for Distribution billing)	Monthly	5 Minutes OR 1 Hour
RTPR	Real Time Price Response Program	Energy	100 kW	100 kW	Yes	± 2 % (± ½ % if meter is used for Distribution billing)	Monthly	1 Hour
RTDR	Real Time Demand Response Resource	Capacity	100 kW	1 kW	Yes	± 2 % (± ½ % if meter is used for Distribution billing)	2.5 business days	5 Minutes
OP	FCM: On-Peak Demand Resources	Capacity	100 kW	1 kW	Yes	± 2 % (± ½ % if meter is used for Distribution billing)	Monthly	1 Hour
SP	FCM: Seasonal Peak Demand Resources	Capacity	100 kW	1 kW	Yes	± 2 % (± ½ % if meter is used for Distribution billing)	Monthly	1 Hour
RTEG	Real Time Emergency Generation Resource	Capacity	100 kW	1 kW	Yes	± 2 % (± ½ % if meter is used for Distribution billing)	2.5 business days	5 Minutes
DARD	Dispatchable Asset Related Demand	Reserve	1 MW	1 kW	Yes	± 1/2 %	1.5 business days	1 Hour
TPRD	Transitional Price Responsive Demand	Energy	100 kW	1 kW	Yes	± 2 % (± ½ % if meter is used for Distribution billing)	2.5 business days	5 Minutes

Figure 6-20: ISO NE Demand Response Markets and Metering Requirements

Source: IRC 2014

PJM

Figure 6-21 presents the metering requirements for PJM's demand response resources. Except for resources under direct control, demand resources must meet their distribution utility's requirement for accuracy or have a max error of 2%. Metering equipment can be either the same as that used for retail service, an independent customer-owned meter or a meter provided by an aggregator. On-site generation meter data can be used if the generation is used for demand reduction only and certified by the aggregator. All metering equipment must meet appropriate ANSI C12.1 and C57.13 standards at a minimum.

Name	Market	Minimum Eligible Size	Minimum Reduction	Metering Requirement	Meter Accuracy	Meter Data Reporting Deadline	Meter Data Reporting Interval
Economic Load Response (Energy)	Energy	100 kW	100 kW	Yes	± 2 %	Event Day + 60 Days	1 Hour
Economic Load Response (Synchronized reserves)	Reserve	100 kW	100 kW	Yes	± 2 %	Event Day + 1 Business Day	1 Minute
Economic Load Response (Day ahead scheduling reserve)	Reserve	100 kW	100 kW	Yes	± 2 %	Event Day + 1 Business Day	1 Minute
Economic Load Response (Regulation)	Regulation	100 kW	100 kW	Yes	± 2 %	Event Day + 1 Business Day	1 Minute
Emergency Load Response - Energy Only	Energy	100 kW	100 kW	Yes	± 2 %	Event Day + 60 Days	1 Hour
Full Emergency Load Response (Limited DR - Capacity Component)	Capacity	100 kW	100 kW	Yes	± 2 %	End-of-Month + 45 Days	1 Hour
Full Emergency Load Response (Extended Summer DR - Capacity Component)	Capacity	100 kW	100 kW	Yes	± 2 %	End-of-Month + 45 Days	1 Hour
Full Emergency Load Response (Annual DR - Capacity Component)	Capacity	100 kW	100 kW	Yes	± 2 %	End-of-Month + 45 Days	1 Hour
Full Emergency Load Response (Energy Component)	Energy	100 kW	100 kW	Yes	± 2 %	Event Day + 60 Days	1 Hour

Figure 6-21: PJM Demand Response Markets and Metering Requirements

Source: IRC 2014

MISO

Figure 6-22 presents the metering requirements for MISO's demand response resources.

Name	Market	Minimum Eligible Size	Minimum Reduction	Metering Requirement	Meter Accuracy	Meter Data Reporting Deadline	Meter Data Reporting Interval
Demand Response Resource Type I (Energy)	Energy	1 MW		Yes	Applicable State Jurisdictional Requirements	Event Day + 53 Days	1 Hour
Demand Response Resource Type-I (Reserve)	Reserve	1 MW		Yes	Applicable State Jurisdictional Requirements	Event Day + 5 Days	5 Minute
Demand Response Resource Type II (Energy)	Energy	1 MW		Yes	Applicable State Jurisdictional Requirements	Event Day + 53 Days	1 Hour
Demand Response Resource Type-II (Reserve)	Reserve	1 MW		Yes	Applicable State Jurisdictional Requirements	Event Day + 5 Days	5 Minute
Demand Response Resource Type-II (Regulation)	Regulation	1 MW		Yes	Applicable State Jurisdictional Requirements	When Cleared Day-Ahead, During Dispatch Day -- next Hour	1 Minute
Emergency Demand Response	Energy	100 kW		Yes	Applicable State Jurisdictional Requirements	Event Day + 103 Days	1 Hour
Load Modifying Resource	Capacity	100 kW		Yes	Applicable State Jurisdictional Requirements	Event Day + 103 Days	1 Hour

Figure 6-22. MISO Demand Response Markets and Metering Requirements

Source: IRC 2014

6.2.5 Metering Performance and Standards

Performance metrics for most meters can be summarized as follows:[233]

- **Accuracy.** Accuracy identifies the difference between measured and actual values. Accuracy estimates should reference specific calibration procedures, including equipment-traceability to National Institute of Standards and Technology (NIST) 2010 equipment and procedures.
- **Precision/Repeatability**. Precision/repeatability refers to the ability of a meter to reproduce the same result for multiple measurements conducted under the same conditions.
- **Turndown Ratio**. Turndown ratio refers to the ratio of flow rates over which a meter can maintain a given accuracy and repeatability. For example, a meter that can measure accurately from "X"

[233] DOE Federal Energy Management Program 2011, Available online at: http://www1.eere.energy.gov/femp/pdfs/mbpg.pdf

units/hr to “Y” units/hr has a turndown ratio of Y:X. A greater turndown ratio refers to a larger range over which a meter can accurately and repeatedly.

American National Standards Institute (ANSI) C12.1 is used for meter accuracy and design. ANSI C12.1 establishes the acceptable performance criteria for new types of AC Wh meters, demand meters, demand registers, pulse devices, instrument transformers, and auxiliary devices.[234] Acceptable in-service performance levels for meters and devices used in revenue metering are stated in the standards, and information on recommended measurement standards, installation requirements, test methods, and test schedules is included in ANSI 12.1.[235] ANSI C12.20, “establishes the physical aspects and acceptable performance criteria for 0.2 and 0.5 accuracy class electricity meters.”[236] In particular, it establishes acceptable performance criteria for electricity meters. Furthermore, accuracy class designations, current class designations, voltage and frequency ratings, test current values, service connection arrangements, pertinent dimensions, form designations, and environmental tests are also covered.[237]

Equipment used to certify meter performance must be traceable to the NIST.[238] Other relevant metering standards include those established by National Electric Code (NEC) for home electrical wiring, National Electrical Manufacturers Association (NEMA) and Underwriters Laboratories (UL) for enclosures and devices, and National Electric Safety Code (NESC) for utility wiring.[239]

6.3 Telemetry Requirements

Telemetry of grid resources enables system operators to monitor loads, generation, and other operational information to ensure reliable and stable operation of the power grid. Resources that offer to provide real-time products in wholesale electricity markets are usually required to have sufficient telemetry and communications capability to receive dispatch signals from the ISO/RTO. The requirements may vary by the size of resource and the type of market in which they participate. These rules continue to evolve and are being revised by system operators as more demand response participates in energy and ancillary services markets. Traditionally, metering has been mostly used for financial settlements and telemetry for operational and dispatch commands. However, as metering technologies improve, and as smaller assets such as DERs become more prevalent in wholesale markets, the distinction between the two roles has blurred. Some ISO/RTOs are beginning to investigate the necessary distinctions between the benefit of and the need for metering and telemetry of DERs. For example, in 2013, the CAISO began a stakeholder process to evaluate the expansion of metering and telemetry options to support emerging business models and to find lower cost solution alternatives.[240] The following section highlights some of the telemetry requirements currently established by ISO/RTOs.

6.3.1 Communication and Telemetry Requirements for DERs

In most ISO/RTOs, telemetry is required for participation in the regulation market, and some require telemetry for spinning reserves as well. Figure 6-23 captures the telemetry requirements for demand response resources across different ISO/RTOs for reserves and regulation markets. ISO/RTO rules and

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234 https://www.nema.org/Standards/ComplimentaryDocuments/C12-1-2008-C-and-S.pdf
235 Ibid.
236 https://www.nema.org/Standards/ComplimentaryDocuments/ANSI-C12-20-Contents-and-Scope.pdf
237 Ibid.
238 http://www.eei.org/issuesandpolicy/grid-enhancements/Documents/smartmeters.pdf
239 Ibid.
240 For more information se: http://www.caiso.com/informed/Pages/StakeholderProcesses/ExpandingMetering-TelemetryOptions.aspx

requirements for programs often change over time. The summaries provided here reflect information provided by the ISO/RTO Council as of February 2014.[241]

Region	Name	Minimum Eligible Resource Size	Minimum Reduction Amount	Aggregation Allowed	Telemetry Accuracy	Telemetry Reporting Interval	Other Telemetry Measurements	Communication Protocol	On-Site Generation Telemetry
CAISO	Proxy Demand Resource Product	500 kW	10 kW	Yes	± 2 %	1 Min Load to DPG; 4 sec DPG to CAISO EMS (resource to eDAC 4-Second eDAC to CAISO)	None	DNP3 or ICCP	No
ERCOT	Non-Controllable Load Resources providing Responsive Reserve Service -- Under Frequency Relay Type	100 kW	100 kW	No	± 3 %	2 Seconds	Multiple Data Points including UFR Status and Breaker Status	ICCP	N / A
ERCOT	Controllable Load Resources providing Responsive Reserve Service	100 kW	100 kW	No	± 3 %	2 Seconds	Multiple Data Points	ICCP	N / A
ERCOT	Controllable Load Resources providing Non-Spinning Reserve Service	100 kW	100 kW	Yes	± 3 %	2 Seconds	Multiple Data Points	ICCP	N / A
ERCOT	Controllable Load Resources providing Regulation Service	100 kW	100 kW	No	± 3 %	2 Seconds	Multiple Data Points	ICCP	N / A
ISO-NE	Dispatchable Asset Related Demand	1 MW	1 kW	Yes	± 2 % (± ½ % if meter is used for Distribution billing)	10 Seconds	None	DNP3	N / A
MISO	Demand Response Resource Type-I (Reserve)	1 MW		Yes	N / A	N / A	N / A	N / A	N / A
MISO	Demand Response Resource Type-II (Reserve)	1 MW		No	N / A	N / A	N / A	ICCP	N / A
MISO	Demand Response Resource Type-II (Regulation)	1 MW		No	Consistent with other ICCP Data	4 seconds	None	ICCP	Yes
NYISO	Demand Side Ancillary Services Program (DSASP-10)	1 MW	1 MW	Yes	Digital data: Maximum error of +0.1 percent of reading	6 Seconds	Regulation Flag, Base Load Interval, Calc Response MW, Beaker Satus	ICCP	Yes
NYISO	Demand Side Ancillary Services Program (DSASP-30)	1 MW	1 MW	Yes	Digital data: Maximum error of +0.1 percent of reading	6 Seconds	Regulation Flag, Base Load Interval, Calc Response MW, Beaker Satus	ICCP	Yes
NYISO	Demand Side Ancillary Services Program (DSASP-Reg)	1 MW	1 MW	Yes	Digital data: Maximum error of +0.1 percent of reading	6 Seconds	Regulation Flag, Base Load Interval, Calc Response MW, Beaker Satus	ICCP	Yes
PJM	Economic Load Response (Synchronized reserves)	100 kW	100 kW	Yes	N / A	N / A	N / A	N / A	N / A
PJM	Economic Load Response (Day ahead scheduling reserve)	100 kW	100 kW	Yes	N / A	N / A	N / A	N / A	N / A
PJM	Economic Load Response (Regulation)	100 kW	100 kW	Yes	± 2 %	2-4 Seconds	None	ICCP or DNP3	No

Figure 6-23. Demand Response Telemetry Requirements by ISO/RTO and Market Product

Source: IRC 2014

Accuracy requirements are typically different for revenue metering and telemetry; however, cost considerations might dictate the use of the same equipment for both functions. At the same time, the correct choice of equipment for telemetry purposes is vital to the performance of the system.

Given recent advancements in metering technology and growth in the number of smaller-sized assets participating in the markets, some ISO/RTOs are reconsidering their metering and telemetry requirements. As an example, MISO relaxed an initial requirement that demand response resources offering any ancillary service must have real-time telemetry when they determined that real-time telemetry was unnecessary for

[241] Available online at: http://www.isorto.org/Documents/Report/20140304_2013NorthAmericanWholesaleElectricityDemandResponseProgramComparison.xlsx

the provision of reliable spinning and non-spinning reserves.[242] The requirements associated with advanced metering, telemetry, and communication equipment and processes can be expensive. As the accuracy and interval frequency of the communication requirements increase, the cost of metering also increases. The share of telemetry costs relative to the total costs of capacity can therefore be greater for smaller assets like DERs as compared to traditional centralized generating assets. The challenge is to identify the rules that obtain the greatest telemetry benefits in terms of visibility, security and controllability of such resources, while balancing the cost and administrative activities.

The CAISO currently does not allow demand response resources to provide regulation or spinning reserves into its markets. However, there are on-going efforts to have these markets open to demand response resources in the near future. The regulation market is not open to demand response in ISO New England. However, pilot programs are underway to examine the ability to change this rule.[243]

6.3.2 Model Information and Telemetry Data

A fully operational integration of economic dispatch, and utilization for grid reliability of demand response and DERs require representation of the resources' operating characteristics in the form of computer models. Currently, modeling to represent demand-side resources for the type of operations needed for full-grid economic and reliability applications vary considerably. Unlike modeling for various types of power plants, which include parameters needed to determine operating modes, ramping capability, operating limits, cost curve, etc., best practices for modeling demand side resources are evolving. Also, unless DER assets are enrolled in the markets, or other means are available to obtain information about the assets, they may not be incorporated into ISO/RTO models. However, there are several modeling initiatives underway to facilitate incorporation of DR and DER into such applications as forecasting, unit commitment, economic dispatch and network analysis, which are important for full integration of these resources with grid operations. It is important to assess the available and applicable IEEE, IEC and other standards, and to classify DR and DER assets for modeling purposes. Moreover, as DERs provide more services to the grid (e.g., utilization of the DR and DER assets for supply of energy, ancillary services, flexibility reserves, and balancing energy), the necessity to incorporate assets' operational, dynamic response and cost characteristics into the economic dispatch of system operators becomes greater.

The electric power network was originally designed around central generation plants and the controls and communication processes were designed to accommodate that type of system. As such, this large system was created, and evolved, based on a unidirectional flow of energy. DER consists of different types of generation assets and energy storage. Many system operators and utilities still treat them as negative load on the system, however, as the penetration of these resources increases, treating them as negative load may not be sufficient. Monitoring and control of the distribution network may become challenging under a framework with a large amount of interconnected DERs. In particular, monitoring and control of multiple assets was not originally conceived under a centralized framework. A standard modeling framework to address DERs may become necessary. One important element of such a model model is the existence of standard communication protocols. The following sections summarize some existing protocols for data exchange and standardized information models.

[242] http://www.raponline.org/document/download/id/6597
[243] http://iso-ne.com/support/faq/atr/index.html

6.3.3 Industry Standards

Several industry standards that exist today are relevant to DERs. The following provides a brief highlight of relevant standards and standard-making bodies.

IEC Standards

IEC 61850-7-420 is a communication standard for DER systems defined by the International Electrotechnical Commission (IEC).[244] Defined as part 7-420 of the Communication Networks and Systems for Power Utility Automation, it is entitled, "basic communication structure for distributed energy resources logical nodes." IEC 61850 is a standard for the design of electrical substation automation and IEC 61850-7 defines the basic communication structure for substation and feeder equipment.

Figure 6-24 illustrates the various components of IEC 61850 and how they relate to other IEC models.

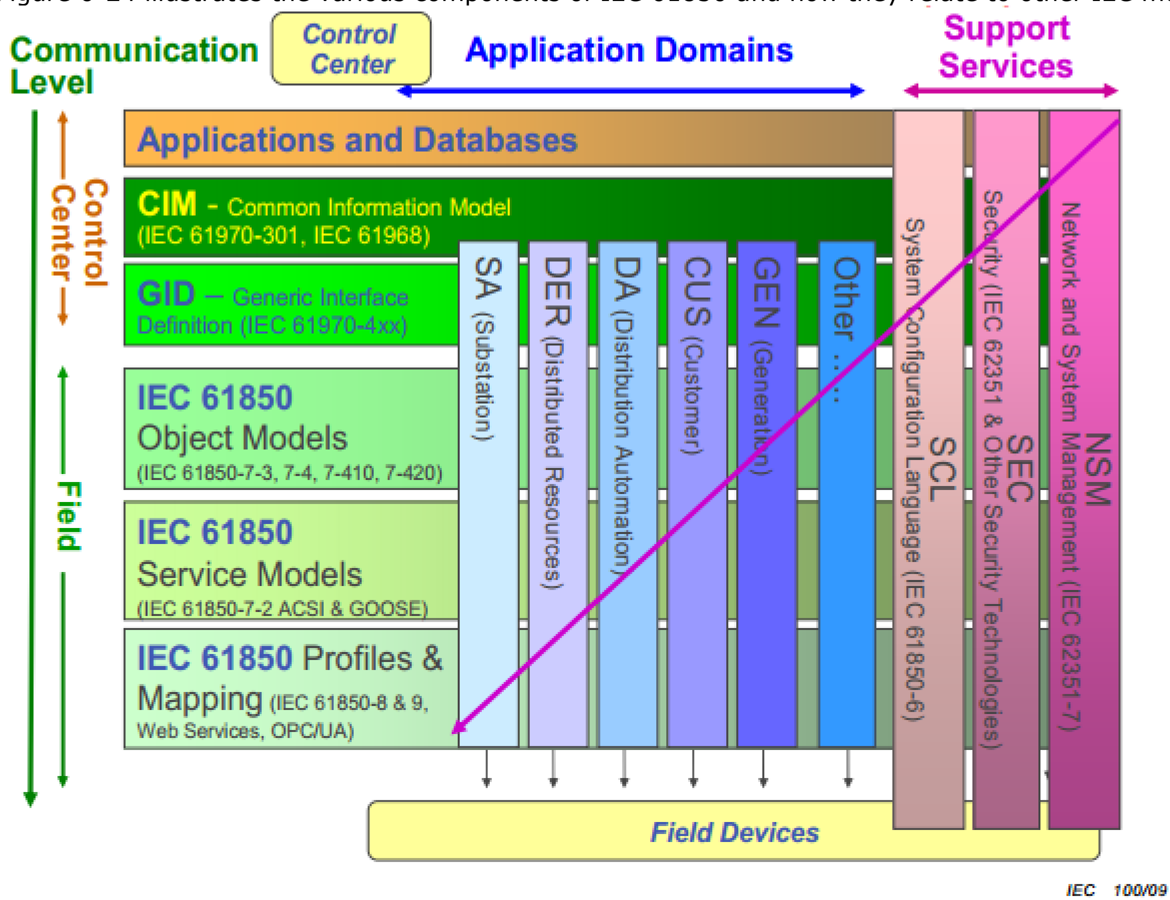

Figure 6-24. – IEC 61850 Modelling and Connections with CIM and Other IEC TC 57 Models

Source: http://webstore.iec.ch/preview/info_iec61850-7-420%7Bed1.0%7Den.pdf

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[244] Available online at: Basic Communication Sturcture for distributed energy resources logical nodes, part

NIST

In response to the Energy Independence and Security Act of 2007 (EISA), NIST developed a three-phase plan to coordinate development of a framework that includes interoperability protocols and standards for Smart Grid devices and systems.[245] This three-phase plan consisted of:[246]

1. Identification and consensus on Smart Grid standards;
2. Establishment of a robust Smart Grid Interoperability Panel that sustains the development of the many additional standards that will be needed; and
3. Development of a conformity testing and certification infrastructure.

Release 2.0 of the NIST Framework and Roadmap for Smart Grid Interoperability Standards details progress made in NIST's three-phase plan since 2009, when the Smart Grid Interoperability Panel was established.

NAESB

The North American Energy Standards Board (NAESB) develops and promotes standards for wholesale and retail natural gas and electricity markets. One of NAESB's services is to provide standards for measurement and verification of demand response and energy efficiency. With regard to metering and telemetry data, these standards cover:

- Metering requirements and accuracy for after the fact metering;
- Meter data reporting intervals;
- Telemetry requirements, accuracy, and intervals;
- Communication protocols;
- Demand Response and Energy Efficiency baseline estimation and adjustment; and
- Energy and demand reduction estimation.

OpenADR

OpenADR is an "open and interoperable information exchange model" for communicating price and reliability signals and which supports automated demand response.[247] OpenADR provides a non-proprietary, open standardized interface that allows electricity providers to communicate demand response signals directly to existing customers using a common language and existing communications such as the Internet. It is currently being developed in conjunction with efforts by NIST to develop Smart Grid standards.

6.4 Measurement and Verification

Traditional generators have a nameplate capacity as an indication of their generation potential; they typically rely on telemetry or metering data to measure and calculate production, settlements and transactions. By contrast, to identify demand response capacity, evaluators must estimate the difference between the load that *would* have been consumed and the load that was consumed during a demand response period. The same is true for behind-the-meter assets which act as load modifiers and may not be

245 http://www.nist.gov/smartgrid/upload/NIST_Framework_Release_2-0_corr.pdf
246 Ibid.
247 http://www.openadr.org/faq#3

independently metered – contributions must be estimated as the difference between a baseline load estimate and the net load that was actually observed.

Meaningful measurement and performance is important as it provides the basis for fair and transparent financial flows to and from market participants or ratepayers.

Measurement and verification (M&V) of demand response has evolved as the use of demand response has evolved – from emergency peak reduction purposes to energy or ancillary service resources. Methods for calculating the reduction have been defined in each jurisdiction and different methods may be appropriate for different purposes. However, meaningful measurement of performance is important as it provides the basis for fair and transparent financial flows to and from market participants and ratepayers. Further, belief in the fairness of the process and transparency of the results is the underpinning of market and stakeholder confidence.

M&V is used from enrollment to settlement of demand response and may also be used in planning processes. In the customer enrollment phase, the resource's capability needs to be determined, i.e. the 'unit capacity.' This is typically based on the peak demand or capacity of the equipment under control. For operations and dispatch, the expected performance of the resource needs to be evaluated, i.e. the 'available capacity.' This is often based on past history and can vary with weather, time of day, or other conditions. For financial settlements, the nominal reduction provided in each interval of an event needs to be calculated, i.e. the actual energy delivered. Typically, this is calculated from the difference between actual usage and an agreed upon baseline calculation, but may also be based on statistical sampling of a randomly selected control group in the case of mass-market aggregators. For planning purposes, it may be useful to project the future performance of an individual resource, based on its past performance relative to its capability, or estimate the impact of a program, product, or aggregated resource as a whole. Having the information necessary to measure and verify participation of demand response resources that are treated as supply is vital to an efficient market. Paying demand response for its ability to provide a reduction affects both loads and conventional suppliers: payments to demand response are allocated to the loads and unresponsive or phantom demand response displaces conventional supply resources. Figure 6-25 summarizes the use of M&V by grid operators.

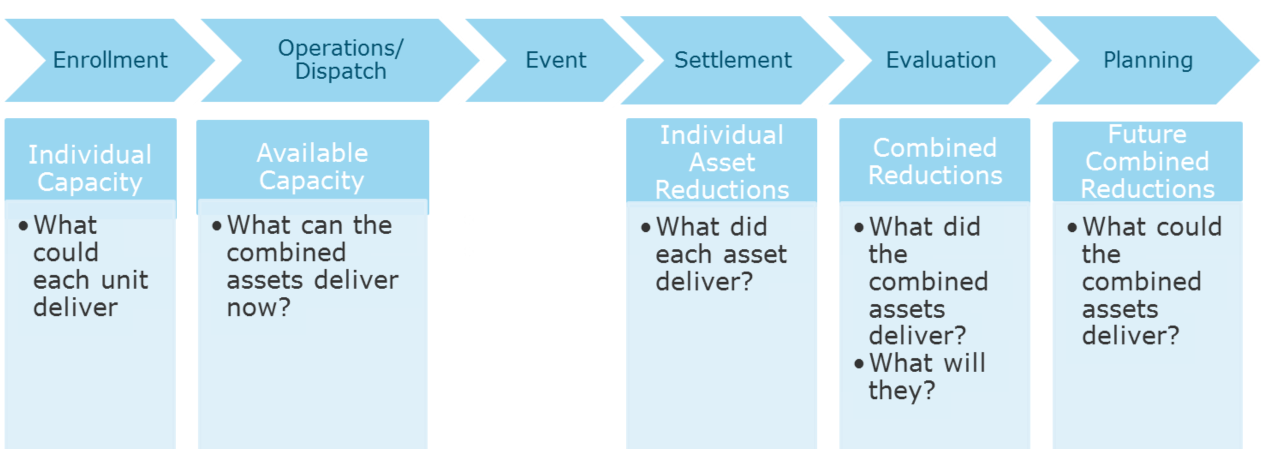

Figure 6-25. Use of Measurement and Verification for Demand Response Purposes

6.4.1 Enrollment Baseline Determination

The purpose of a performance evaluation methodology is to calculate the load reduction from a DER resource, i.e., what the load *would have been* had the DR event not happened, or the DER resource not operated. A common approach is to calculate a 'baseline', which is an estimate of the 'would-be' load in order to estimate the reduction that occurred. Figure 6-26 illustrates the baseline concept.

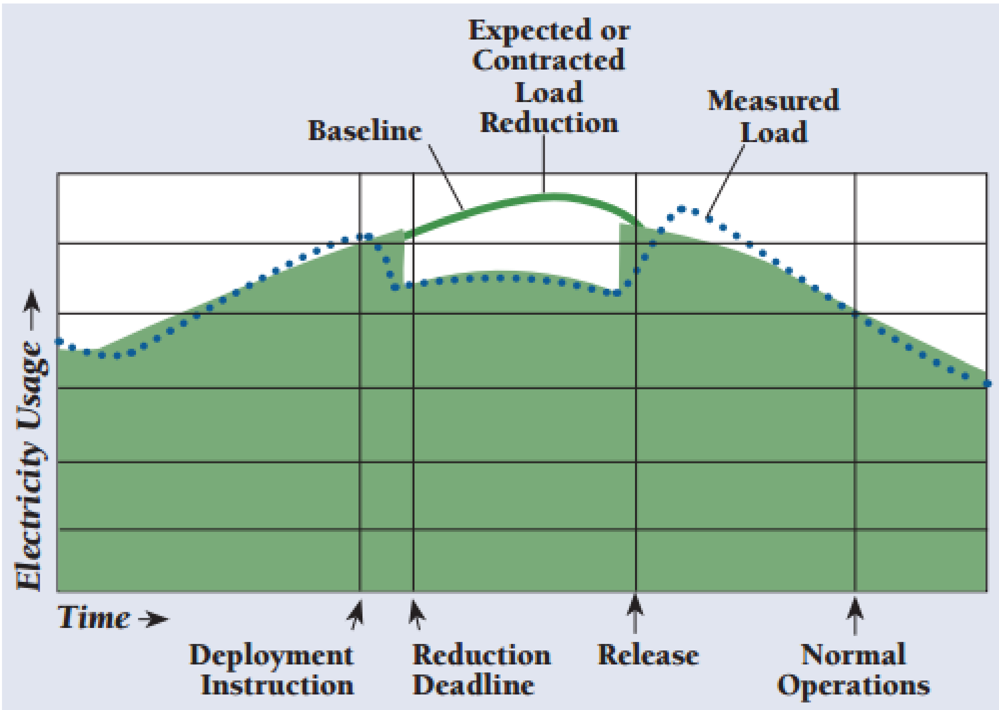

Figure 6-26. Demand Response Baseline Illustration

Source: NERC 2011

The ideal performance evaluation methodology is designed for accuracy, flexibility, reproducibility, and simplicity, among other features. In other words, it should provide an accurate estimate of the load so that demand response resources are credited only for load reductions associated with the event and baseline manipulation is minimized. The methodology should be flexible enough to allow for future resources, and take into consideration extraordinary circumstances such as excessively high load on event days and exclusions that may reduce the accuracy of the estimate. The baseline methodology also needs to be simple enough to be conveyed in a straightforward language so that the requirements and calculations are readily understood and can be reproduced by the demand response resource, aggregator and program impact evaluator. NAESB has outlined standards in common performance evaluation method types for demand response, including:

- **Maximum Base Load.** This is based solely on a demand resource's ability to maintain its electricity usage at or below a specified level during a demand response event.
- **Meter Before / Meter After.** The electricity demand over a prescribed period of time prior to deployment is compared to similar readings during the Sustained Response Period.
- **Baseline Type-I.** The baseline is based on a demand resource's historical interval meter data and may also include other variables such as weather and calendar data.

- **Baseline Type-II.** This baseline calculation uses statistical sampling to estimate the electricity usage of an aggregated demand resource where interval metering is not available on the entire population.
- **Metering Generator Output.** This method is based directly on the output of a generator located behind the demand resource's revenue meter.

Different methodologies are appropriate for different market services, as outlined in Figure 6-27.

Performance Evaluation Methodology	Valid for Service Type			
	Energy	Capacity	Reserves	Regulation
Maximum Base Load	✓	✓	✓	
Meter Before/Meter After	✓	✓	✓	✓
Baseline Type-I Interval Metering	✓	✓	✓	
Baseline Type-II Non-Interval Metering	✓	✓	✓	
Metering Generator Output	✓	✓	✓	✓

Figure 6-27: Demand Response Performance Evaluation Methodologies and Uses

Source: NAESB 2011

In addition, it may be appropriate to use different methods for the different processes throughout the deployment process, such as capacity measurement during enrollment versus reduction measurement for operations, settlement in retail versus wholesale markets, forecasting, and planning versus real-time estimates, etc.

Further, when a baseline approach is used, rules for how the baseline is calculated, i.e. which historical metering interval should be used as basis for the calculation and which days to exclude from the baseline estimate, must be determined. The most common type of baseline is the "*X* of *Y*" baseline, meaning, for example, that five out of the ten most recent weekdays are chosen for determining the baseline. Figure 6-28 describes in general terms some of the baseline methods across ISOs.

ISO	Average of	Out of
CAISO 10-in-10	10 most recent weekdays	10 most recent weekdays
ERCOT Mid 8-of-10	10 most recent weekdays, dropping highest and lowest kWh days	10 most recent weekdays
MISO 10-in-10	10 most recent weekdays	10 most recent weekdays
NYISO	5 highest kWh days	10 most recent weekdays
PJM	4 highest kWh days	5 most recent weekdays

Figure 6-28: Baseline Calculations across ISOs

Note: These are generalizations of the weekday baseline calculation. Weekend baselines are calculated in a similar nature, but generally require fewer days (e.g., 4 most recent weekend days).

Usually, some type of additional adjustment is still needed as the days chosen for a demand response event often are extreme load days, and recent days may not accurately capture the 'would-be' load of an event day. Figure 6-29 highlights some of the adjustments often used to estimate a baseline. Note that in this case, the unadjusted baseline (pink line) is well below the actual load, which would indicate that a reduction did not take place at all. This highlights some of the challenges with estimating baselines for performance evaluation and financial settlements.

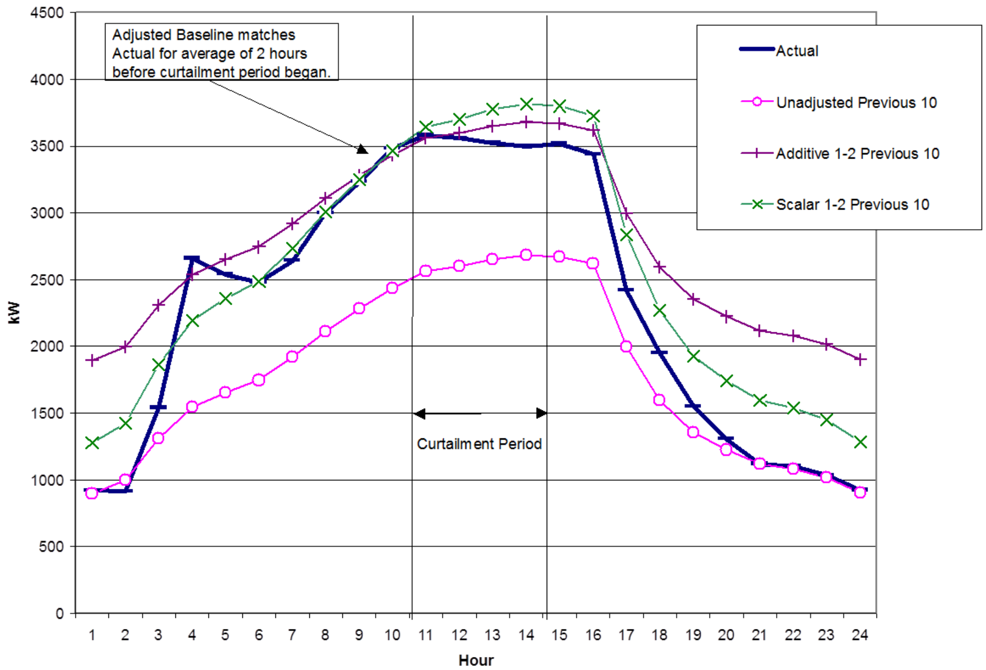

Figure 6-29: Baseline Estimation Examples

As noted in the previous Figure 6-27, a baseline methodology is not appropriate for providing regulation services. Instead, a "meter before/meter after" method is typically used because operators need real time monitoring to manage operations and dispatch accordingly.

7 REFERENCES

PLACEHOLDER FOR FINAL DRAFT

8 APPENDICES

PLACEHOLDER FOR FINAL DRAFT

About DNV GL

Driven by our purpose of safeguarding life, property and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our 16,000 professionals are dedicated to helping our customers make the world safer, smarter and greener.