February 7, 2014

FURTHER COMMENTS ON NYISO DER STUDIES

By NECHPI's Policy and Regulatory Committee

On Behalf of NECHPI, a 501(c)(6) corporation

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List of Acronyms and Abbreviations

501(c)(6)	Section 501(c)(6) of the IRC exempts business leagues
AutoDR	Automated demand response
CA	California
CAISO	California Independent System Operator
CEC	California Energy Commission
CHP	Combined Heat and Power and/or Clean Heat and Power
CHP Zones	CHP development zones established under State law or other criteria, possibly an ISO/RTO sub-zone
CO2	Carbon Dioxide
Commission	New York Public Service Commission
Con Ed	Consolidated Edison Company of New York
CPUC	California Public Utility Commission
CR (ERCOT)	Contingency reserve service
DER (s)	Distributed Energy Resource(s)
DG	Distributed Generation
DPS	NYS Department of Public Service
DR	Demand Response
DRMS	Demand Response Management System
EDGE	Electricity Distribution Grid Evaluator MODEL – A TOOL DEVISED BY RMI
EEPS	Energy Efficiency Portfolio Standard
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FFR (ERCOT)	Fast Frequency Response Service
FIT	Feed-In Tariff
Governor	NY Governor Andrew Cuomo
Green Bank	Innovative Financing Resource
ICAP	Installed Capacity Program
ICTI	Information/communications technologies
IP	Indian Point Nuclear Facility
ISO	Independent System Operator
ISO NE	ISO New England (an RTO)
kW	Kilowatt
kWh	Kilowatt-hour
LMP or LBMP	Location Based Marginal Price
LSE	Load Serving Entities
MISO	Midcontinent Independent System Operator
MW	Megawatt
MWh	Megawatt-Hour
NECHPI	Northeast Clean Heat and Power Initiative
NEM	Net Energy Metering
NERC	North American Electric Reliability Council
NOI	Notice of Intent (as in FERC NOI)
NOPR	Notice of Public Rule Making as in FERC NOPR
NOx	Criteria Pollutant for Nitrous Oxides
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator (an RTO)
NYSERDA	NYS Energy Research and Development Authority
NYSRC	NYS Reliability Council
OATT	Open Access Transmission Tariff
PFR (ERCOT)	Primary frequency response service

PJM	Pennsylvania Jersey Maryland Interconnection (an RTO)
PM10	Particulate matter concentrations less than 10 microns in diameter
Prosumerization	The trend for consumers to evolve from more passive and deterministic consumption patterns to more active ones.
PSC	New York Public Service Commission
PURPA	Public Utility Regulatory Policy Act of 1978
PV	Photovoltaic
RAP	Regulatory Assistance Project
REC	Renewable Energy Credit
RES	Renewable Energy Sources
RGGI	Regional Greenhouse Gas Initiative
RMI	Rocky Mountain Institute
RPS	Renewable Portfolio Standard
RR (ERCOT)	Up and down regulating reserve service
RTO	Regional Transmission Operator
SBC	System Benefits Charge
SCR	NYISO's Special Case Resources Program
SG	Smart Grid
SGIP	Self-Generation Incentive Program (SGIP)
SHP	Separate Heat and Power
SIR (ERCOT)	Synchronous inertial response service
SIR (NYS)	Standardized Interconnection Requirements
SMUD	Sacramento Municipal Utility District
SOx	Criteria Pollutant for Sulfur Oxides
SR (ERCOT)	Supplemental reserve service (SR)
SREC	Solar Renewable Energy Certificates
T&D	Transmission and Distribution
T&D Upgrade	Upgrade to transmission and distribution systems infrastructure.
Tranche	"Tranche" is used in this context to refer to a multi-staged process of bidding into a capacity market. Different values are ascribed to resources based on the capabilities the resource offers. The most highly valued resources are paid at the highest level.
Transactive Energy	the use of economic transactions to coordinate distributed energy resources to meet multiple generation, transmission and distribution objectives
VG	Variable Generation

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Executive Summary

Because of an increasing industry focus on the role of distributed energy resources ("DERs") in the evolution of the U.S. electricity grid to a 21st century power system, ***NECHPI[1] feels it is in its best interest to focus on supporting, and leveling the playing field amongst, all distributed-energy resources, with a focus on support for both the general class of distributed generation ("DG") assets as well as those for combined heat and power ("CHP" and/or "Clean Heat and Power") specifically during this critical development period*. *[Finding No. 1]***[2]

There are approximately 800 MW at 390 CHP installations between 50 kW and 50 MW in New York State. Since the start of NYISO operations an average of 20-+ MW has been added each year at approximately 250 sites averaging over 1 MW per site. With respect to interfaces with the bulk power system these resources have been mainly "gridlocked" for whatever reason, because of either internal design and operational constraints or external constraints, including difficulties with interconnection rules, onerous standby tariffs, and so on. There are over 5,800 MW of CHP of all sizes at 500 sites and additional technical potential for approximately 9,500 MW.[3]

Today, there is a particular focus of current initiatives on smaller-sized installations. While larger-sized opportunities may be more limited, the fresh focus on microgrids and district energy and a new focus on community-based projects is also providing a variety of opportunities for larger installations. If certain retail and wholesale market rules and regulations were changed, there would be significant potential for CHP to experience rapid growth going forward.

New York State where the New York Independent System Operator ("NYISO") situates is now one of the most exciting emerging markets for DERs of all stripes:

- Governor Andrew Cuomo, ("The Governor") has clearly set the stage for a dramatic scale-up of DERs in the state's energy mix. (Cuomo, Jan 14, 2014) He installed fresh leadership in key positions and launched a number of new initiatives. He is pushing the urgency in upgrading New York's electric grid with a $17 billion renewal plan; espousing a massive grid hardening and modernization effort; positioning New York State as a global leader in energy storage technology, including applications in grid storage, transportation and power electronics; extending the two-year-old NY-Sun Initiative by adding nearly $1 billion to the solar program; improving the Regional Greenhouse Gas Initiative ("RGGI"), with a goal of reducing power-plant pollution in the region by 15% by 2020; and advancing the deployment of community-based microgrid solutions with $40 million allocated to create at least 10 microgrids. This is a

[1] Northeast Clean Heat and Power Initiative (NECHPI) is 501(c)(6) business league functioning primarily in the seven northeastern states. Until 2012 it was simply a voluntary association. To be exempt, a business league's activities must be devoted to improving business conditions of one or more lines of business as distinguished from

[2] References throughout in italicized brackets *[Finding No. 1]* refer to *Findings* by NECHPI collected at pages 5-7.

[3] NECHPI employs data obtained from ICF International

significant move and will require substantial changes to both retail and wholesale markets to allow their integration into the electric grid.

- The New York State Public Services Commission ("PSC" or "Commission") is moving to change the regulatory paradigm and advance substantial changes to existing utility business models. (NY Public Service Commission, 2013) The Commission has launched a process against the timetable for expiration (and renewal/revitalization) of existing authorization of System Benefits Charges ("SBC"), the Renewable Portfolio Standard ("RPS") and the Green Bank to change the regulatory structure so that utilities are not only indifferent to how much power they sell but are able to receive incentives to support efficiency programs. The goal is to change the regulatory model so that distributed resource performance and incentives are not confined to narrow silos meeting limited single metric targets but are integrally bound to the utilities' business model. *The results, including active load management, active load bidding and expanded ancillary markets to recognize a fuller value of local resources, will necessarily effect and help shape the NYISO's evolving missions with distributed energy resources. [Finding No. 2]*

  In the order, the PSC stated that "…the time has come to manage the capabilities of customer-based technologies as a core source of value to electric customers. In addition, full integration of load management capabilities into energy supply and grid-management decisions will improve system-wide reliability, efficiency, and resiliency at just and reasonable rates for New Yorkers." (NY Public Service Commission, 2013) This is a highly significant statement as it focuses on managing loads, whether behind the meter and or in front of the meter close to loads such as microgrids and community-based solar. A bottoms-up approach to grid management is profoundly different from the existing centralized, top-down methodology and will have implications for how both the retail and wholesale markets and organized and managed.

  A vast effort is underway by the Department of Public Service Staff to produce a vision statement, assessment of objectives and means and to propose an adaptation and adoption plan to the Commission at a second session March 2014. It's findings, recommendations, and the ensuing Commission-approved plan will provide a significant context for the review of the NYISO consultant's DER report. For example, they can be expected to identify that NY's pending microgrids will require attention dealing with interconnection and standby rates. The later is a State regulatory issue. The former is both a State issue and potentially a NYISO issue.

  To fully implement, the NYISO/bulk system may require new tariffs and/or dispatch models, in order to integrate and value load optimization. Action by FERC may be required. Direct tariff changes will be further needed to accommodate demand response ("DR") and distributed generation ("DG"). Will further changes be needed indirectly to adjust to a less volatile bulk system? Will the system be less or more volatile with the greater interaction of distributed resources with loads, with each other and with the bulk power system? [Finding No. 3]

- The Indian Point Implementation Plan (Consolidated Edison and NYSERDA, 2014)recently filed in response to directives of the Governor and the Commission, is designed to achieve 125 MWs of permanent, peak-coincident electric load reductions by June 2016: 100 MWs through energy efficiency and demand reduction and 25 MWs through CHP.[4] The CHP incentives build upon CHP programs authorized for SBC 4th cycle in 2012, most notably for smaller packaged pre-qualified CHP systems in the 50 to 1,300 kW range. The prior program is available both upstate and downstate. The 25 MW increment applies in the Con Ed territory.

Building owners, building managers who are Con Ed electric customers and third-party developers acting on behalf of building owners and managers will be eligible for incentives based on their demand reduction for projects completed before June 2016. Measures eligible for incentives include, but are not limited to: thermal storage, battery storage, demand response enablement, building management systems, chiller/heating, ventilation and air conditioning, lighting and fuel switching. Customers will receive incentives for permanent reduction during or permanent shifting of electric load from peak demand hours. Installing equipment that enables customers to participate in the NYISO Installed Capacity Special Case Resources program via automated demand response for short-term curtailment of peak load will also be eligible under the program.

This is another step in the right direction to integrate DERs into the grid; however, wholesale market rules will need to be aligned to maximize participation of eligible resources, most particularly CHP.

- There are many other significant DER initiatives in the state, many managed and funded by NYSERDA. (NYSERDA, 2014) Many of the referenced efforts as well as others not listed above are being coordinated by NYSERDA (e.g., RPS oversight and the Green Bank implementation). *NYSERDA could provide a substantial resource to the NYISO as it addresses DER resources retail and wholesale market changes to ensure that policies, rules and regulations are aligned and maximized to support the integration of DERs into the generation, transmission, distribution and behind-the-meter infrastructure in a safe, reliable manner. NECHPI supports clear lines of communication between and among the NYISO, NYSERDA and the DPS/PSC. [Finding No. 4]*

- NYISO's DER initiative, in concert with NYS PSC's efforts, could fundamentally change both wholesale and retail electricity markets in the state, enabling the scale-up of DERs in a systematic, financially viable manner.

Across the country, both wholesale and retail power markets are in a state of flux, and the State of New York has its work cut out for it. As a clear and highly current example, solar renewable-energy certificate ("*SREC*") markets are extremely volatile at best and have experienced rapid cycles of both over- and under-supply across the markets where they exist. Net metering is the middle of substantial turmoil as utilities and solar industry stakeholders debate the merits or lack thereof of the program. Congress is in the throes of examining tax policy, and it is still unclear whether the federal tax incentives for wind will be extended, will remain in place for CHP and geothermal beyond 12/31/16 and/or will be extended for solar beyond 12/31/15. The uncertainty of the federal tax-incentive environment certainly makes obtaining long-term financing difficult on capital-intensive projects such as CHP, most

[4] The detailed implementation plan in response to Commission Order was filed at the PSC on February 3, 2014 with comments due on February 17, 2014. Implementation is already underway. NYSERDA's next CHP Expo is being held in NYC on February 26, 2014.

particularly if other incentives and revenue streams (e.g., from wholesale markets) are not available as they are for other DERs such as solar.

We at NECHPI believe the focus going forward in both wholesale and retail markets should be on establishing the specific costs and benefits of each DER and on developing and implementing market rules, tariffs and regulations which target a appropriate energy-resource mix to support a distributed future. CHP is a key resource in that mix, and incentives, rules and regulations should provide a means for it to take its proper place in the power system of the future. This is a brave new world of energy resources, which are distributed in nature, and how they are rolled out, integrated into the electric grid and supported by both wholesale and retail markets will be critically important to the grid's long-term health, resiliency, reliability and power quality. [Finding no. 5]

NECHPI's Findings and Observations

NECHPI's Policy and Regulatory Committee has extracted a group of findings and observations regarding the interests of its members and associate. They are cross-referenced to the page number on which they are discussed.

1. *NECHPI feels it is in its best interest to focus on supporting, and leveling the playing field amongst, all distributed-energy resources, with a focus on support for both the general class of distributed generation ("DG") assets as well as those for combined heat and power ("CHP" and/or "Clean Heat and Power") specifically during this critical development period. (p 1)*

2. *The results of the PSC's reformation of utility regulation, including active load management, active load bidding and expanded ancillary markets to recognize a fuller value of local resources, will necessarily effect and help shape the NYISO's evolving missions with distributed energy resources, including CHP. (p 2)*

3. *To fully implement the PSC's vision, the NYISO/bulk system may require new tariffs and/or dispatch models, in order to integrate and value load optimization. Action by FERC may be required. Direct tariff changes will be further needed to accommodate demand response ("DR") and distributed generation ("DG"), including various configurations of CHP and microgrids. Will further changes be needed indirectly to adjust to a less volatile bulk system? Will the system be less or more volatile with the greater interaction of distributed resources with loads, with each other and with the bulk power system? (p 2)*

4. *NECHPI strongly supports the efforts of State Policy as implemented by NYSERDA to facilitate CHP and believes that the NYSERDA could provide a substantial resource to the NYISO as it addresses DER resources retail and wholesale market changes to ensure that policies, rules and regulations are aligned and maximized to support the integration of DERs into the generation, transmission, distribution and behind-the-meter infrastructure in a safe, reliable manner. NECHPI supports clear lines of communication between and among the NYISO, NYSERDA and the DPS/PSC. (p 3)*

5. *We at NECHPI believe that the focus going forward in both wholesale and retail markets should be on establishing the specific costs and benefits of each DER and on developing and implementing market rules, tariffs and regulations which target a appropriate energy-resource mix to support a distributed future. CHP is a key resource in that mix, and incentives, rules and regulations should provide a means for it to take its proper place in the power system of the future. This is a brave new world of energy resources, which are distributed in nature, and how they are rolled out, integrated into the electric grid and supported by both wholesale and retail markets will be critically important to the grid's long-term health, resiliency, reliability and power quality. (p 4)*

6. *The electricity system of the future is likely to encompass an increasingly diverse and interconnected set of actors, with widely varying assets, behaviors, and motivations. The conversations are just beginning about how to integrate storage and microgrids, for example, and we believe that it is in NECHPI's interest if we recommend an approach that helps NYISO and the State of New York accommodate the full array of distributed-energy resources while we achieve our own goals along the way. (p 9)*

7. *We believe <u>a customer/load-centric approach to grid management</u> will be needed to ensure power reliability, security and revenue streams to support a future of significant levels of DERs. The growing complexity of DERs, on a stand-alone basis or in combination, being installed directly in front of and behind the meter are providing both challenges and opportunities to the marketplace: challenges in monitoring and optimizing the wide array of resources into a single, smart digital energy network and opportunities for solving grid reliability and peak-demand contingencies at local distribution and grid-node levels to boost system efficiency and maximize returns on investment for DER assets. [p 10]*

8. *In NECHPI's view, smart-grid platforms, such as microgrids, responsive-demand solutions and virtual power plants, are being developed to improve performance of critical DER assets to support business up-time, combat high and increasing energy costs, boost reliability of electricity service, realize significant responsive-DR potential and resolve generation capacity – customer load mismatches. Ultimately, we believe that integrated, end-to-end bidirectional information/communications technologies ("ICT") solutions, using logic-based, big-data grid analytics and advanced predictive technologies, will be key to the success of the 21st century power system. In particular, combining the different and complementary characteristics of distributed generation such as CHP and/or solar with energy storage, demand response and distributed intelligence will be essential in increasing the value of variable output generation in the energy market. Both wholesale and retail markets must adapt to these innovations, not only for individual DERs but also for their many likely combinations. (p 10)*

9. *NECHPI believes that wholesale and retail electricity markets are converging as a result of the increasing presence of DERs on the grid. (p 14)*

10. *NECHPI believes that CHP and energy storage represent DERs that have the most difficulty finding their established places in both retail and wholesale markets, though for very different reasons. CHP has a history, most particularly with utilities, which has not been altogether positive, and we believe this on-going issue has resulted in low participation rates in wholesale markets and has*

negatively affected how it is compensated in both wholesale and retail markets. Coupling Energy Storage with CHP (both thermal and electric) offers new opportunities that should not be rejected out of hand because "we don't do that." We further believe that this is the proper time to reassess the tariffs, market rules, regulations and policies that have accreted over time, are misaligned and have resulted in a diminished access to capital, functioning as deterrents to growth in spite of the numerous positives and glowing reports of CHP's renewed role in a resilient, flexible, and reliable grid as critical infrastructure. (p 18))

11. *Thus, NECHPI fully realizes that given each DER's unique characteristics, there will likely be no single approach to integrating DERs into market design. Instead, local contextual and site-specific factors will figure prominently in market designs that result in the coordinated deployment of centralized and distributed energy resources, as well as in the treatment of hybrid market actors such as microgrids, which represent a combination of DERs, including CHP. (pp 19-20)*

12. *NECHPI's Policy/Regulatory Committee has evaluated various approaches to valuing the costs and benefits of DERs and has found the DER definition of Rocky Mountain Institute ("RMI"), as a third-party independent evaluator, very useful. (p 19)*

13. *In NECHPI's estimation, RMI's approach is an excellent justification as to why CHP should be treated on an equal footing with other DERs and even given precedence in some cases (e.g., for critical infrastructure and resiliency). (p 22)*

14. *NECHPI believes that this confluence of factors will likely drive increased adoption of the full spectrum of renewable and distributed resources, including CHP, requiring a detailed understanding of DERs' benefits and costs in the context of a changing system. From this point, rational pricing structures and business models can be better aligned, enabling greater economic deployment of DERs and lower overall system costs for ratepayers. (p 24)*

15. *We also recognize the significant set of regulatory tariff issues being discussed by the Regulatory Assistance Project at NARUC'S Winter Meeting February 11. While targeting at State regulation they also should apply to NYISO-level and FERC jurisdiction. (p 25)*

16. *We view NYISO's role as helping to facilitate the dialogue between the Public Services Commission and utilities in the state to begin the evaluation of these alternatives in order to ensure that the underpinnings for the rollout of distributed energy resources are properly valued, supported and integrated with all of the policies and regulations in place or being revised, updated or considered for implementation. In addition, given the convergence of retail and wholesale markets because of the emergence of DERs and a grid driven by customer-driven resources, NYISO and the state's PSC will need to work closely together to ensure that rules and regulations are aligned and function smoothly together to support a rapidly evolving grid. (p 25)*

17. *NECHPI believes that many existing plants can be retrofitted with technologies to improve operational flexibility performance, including some CHP plants. In addition, other DERs, such as large pools of aggregated demand response, especially when combined with storage options, can provide low-cost, bi-directional flexibility on the demand side that can also be valuable in*

integrating variable renewable energy, particularly when compared to traditional, centralized generation. [p 27]

18. *NYISO is currently not an attractive wholesale market for CHP. NECHPI is very concerned about this. Enormous amounts of existing and potential CHP remain under-utilized. (p 30)*

19. *CHP participation in NYISO wholesale markets has decreased over the last three years because of changes in certain market rules, (e.g. the ICAP program), and NECHPI feels strongly that the ability to participate in the range of wholesale markets could greatly increase CHP's attractiveness to financing sources, in addition to the ability to receive Green Bank support. (p 30)*

20. *NECHPI avers that A-06 Operating Reserve Criteria substantially limits the ability of CHP to participate in and derive financial benefits from the ancillary-services market and needs to be reviewed. [p 31]*

21. *NECHPI recommends market mechanisms that support new approaches to CHP plant designs, flexibility in contracts and concrete recognition of the contribution of CHP resources to grid system stability and reliability. (p 31)*

22. *We urge the development of policies that allow the design of "oversized" CHP generation for a more dispatchable resource, as an example, and of possibly supporting utility joint ownership with third parties that are in designated locations where the benefits of CHP can be optimized. We believe this will be necessary if the role that CHP plays in the electric grid is to grow. Additionally, CHP sites serve as preferred locations to add any NYISO required peaking or black start resources, in that these sites are a more cost effective placement of these assets in that they are continuously active with close supervision and afford avoidance of duplicated siting, permitting, staffing, grid interconnection and other costs. (pp 31-32)*

23. *In addition, NECHPI recommends that NYISO's policymakers work with the State of New York to help enable the PSC to accomplish the following:*
    - *Expand resource design to include aggregation of multiple locations and zones into a single resource within reasonable limitations.*
    - *Allow behind-the-meter wholesale-market participation for CHP, when it is an on-site energy resource.*
    - *Establish a workable mechanism for CHP in resource adequacy and long-term procurement processes. As with utilities, NYISO does not include CHP in its loading order or its resource-adequacy and long-term planning processes. This economically disadvantages CHP in a significant fashion.*
    - *Going forward, take advantage of FERC's market-driven stances related to DERs and support the development of new market formulations for improved reliability and efficiency and energy/reserve procurement. A new market formulation under development by Sandia Laboratories represents energy and reserve products in terms of standardized contracts whose terms cover a broad range of system service needs, including power increments, ramp rates and energy capacity. These contracts are designed to provide transparent financial instruments for the pricing and procurement of energy and reserves*

in forward markets as well as blueprints for the physical deployment of energy and reserves in real time. To ensure a level playing field, all resources capable of satisfying system service needs, including CHP, can and should submit supply offers for the provision of these needs, regardless of their physical forms.

- *Establish a criteria to account for the efficiency of natural gas utilization, i.e., to avoid the use of natural gas in separate heat and power (SHP) generation where no more than 60% is converted to useful energy, and motivate the natural gas to be used in CHP where it can be converted to as much as 90% useful energy. This ought include an accounting of the CO_2 emissions from the combustion of the natural gas (and the credit for the avoided CO_2 from separate heating or cooling fuel as well).*

NECHPI believes that these changes are not as far in the future as one might suspect. It must happen sooner rather than later. The level of uncertainty in both generation and load is increasing rapidly. The provision of reserve will increasingly involve participation from both the supply and demand sides of the market. Not only will demand-side participation increase, but some resources, such as energy storage systems, will also blur the boundaries between supply and demand.

Further, the uncertainty of generation is increasing as a function of intermittent renewable-energy penetration. The uncertainty of load is increasing as a result of the emergence of demand-response resources. Taken together, this will entail new market designs that are standardized, transparent, and driven by market requirements, including those that are localized. CHP has a critical role to play in the emergence of this new market design but can only do so if it is integrated into NYISO's resource-adequacy and long-term planning processes. (pp 32-33)

24. *NECHPI believes that if the right contracting mechanisms are in place, projects could in theory be custom-built to provide the services of greatest need to the procuring entity and tailored to the operating environment and operational needs of the utility* and RTO/ISO. *(p.34)*

Distributed Energy Resources – Definition, Context and Trends

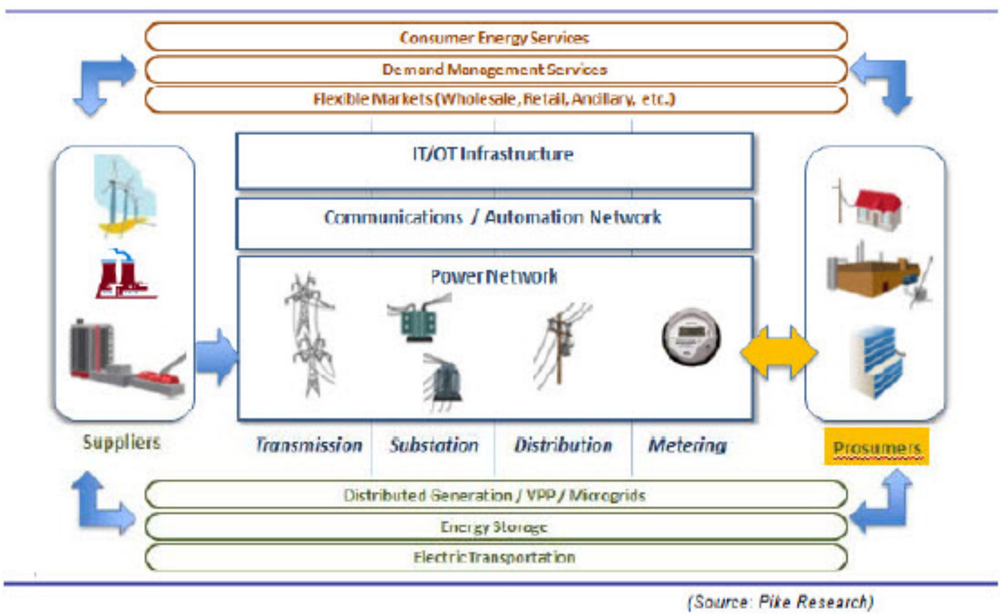
The antiquated U.S. grid was not built to handle the integration of distributed energy resources ("DERs"). The proliferation of DERs behind the meter and at the edge of electricity networks in particular is most likely one of the greatest technical challenges ever faced by the modern electricity industry. The grid's top-down architecture was not built to accommodate significant penetrations of DERs, let alone variable DERs.

DERs are defined by RMI as demand- and supply-side resources that can be deployed on both the customer side and utility side of the meter (e.g., shared community resources, microgrids and other localized energy-resource formats). (Rocky Mountain Institute, 2012)

They include distributed generation (solar, wind, CHP, geothermal and hydropower), distributed flexibility and storage (e.g., demand response, electric vehicles, thermal storage, battery storage), energy efficiency and distributed intelligence (e.g., communications and control technologies and advanced forecasting technologies).

The following is a depiction of the bi-directional (energy and information), increasingly complex 21st century power system in which DERs figure as key energy resources:

Figure 1 – Depiction of Bi-directional (Energy and Information) In 21st Century Power System



As a result, the electricity system of the future is likely to encompass an increasingly diverse and interconnected set of actors, with widely varying assets, behaviors, and motivations. The conversations are just beginning about how to integrate storage and microgrids, for example, and we believe that it is in NECHPI's interest if we recommend an approach that helps NYISO and the State of New York accommodate the full array of distributed-energy resources while we achieve our own goals along the way. [Finding No. 6] The following is a context for the approach.

The behaviors of many players must be aligned to match fluctuations of supply and demand in real time. Investments in distributed resources must be made with a view to all of the variations in specific locations and timeframes in the value and cost of the electricity supply. The roles of both grid operators and utilities in orchestrating these changes, particularly how distributed energy resources interact with its electric system, will be a critical factor in achieving favorable outcomes for all stakeholders.

A recent SmartGridNews Article summarizes the matter succinctly: "In our experience, by optimizing both supply side value buckets (e.g., energy, capacity, ancillary services) simultaneously with grid-based value buckets (e.g., improved reliability, voltage reduction, line loss mitigation, deferral of distribution assets, and dynamic dispatching of DG against intermittent wind/sun), utility pilot examples have already shown two to fivefold increases in cost savings from optimally tapping into the right mix of resources at a more granular level." (Osterhus, 2014) Thus, Osterhus argues there is an optimal mix of demand-side and supply-side resources for each circuit and a significant opportunity to yield a more valuable "bang for the buck" by intelligently targeting the right mix of resources to each circuit.

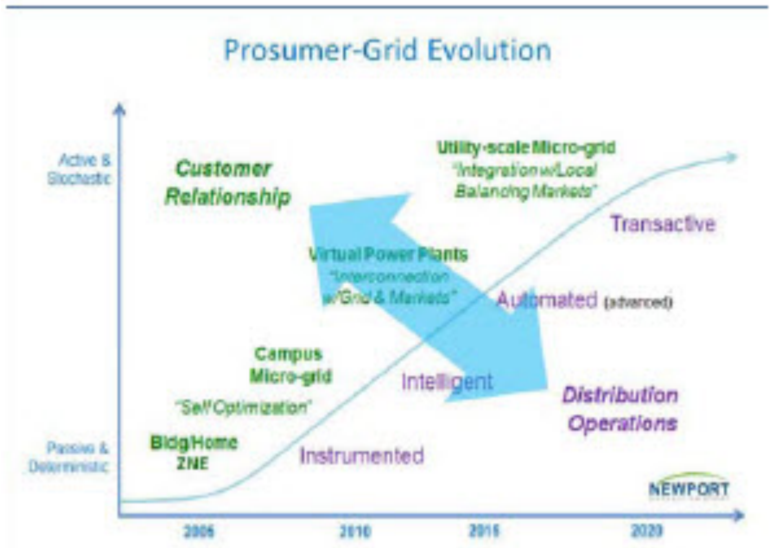
We believe a customer/load-centric approach to grid management will be needed to ensure power reliability, security and revenue streams to support a future of significant levels of DERs. The growing complexity of DERs, on a stand-alone basis or in combination, being installed directly in front of and behind the meter are providing both challenges and opportunities to the marketplace: challenges in monitoring and optimizing the wide array of resources into a single, smart digital energy network and opportunities for solving grid reliability and peak-demand contingencies at local distribution and grid-node levels to boost system efficiency and maximize returns on investment for DER assets. [Finding No. 7]

In NECHPI's view, smart-grid platforms, such as microgrids, responsive-demand solutions and virtual power plants, are being developed to improve performance of critical DER assets to support business up-time, combat high and increasing energy costs, boost reliability of electricity service, realize significant responsive-DR potential and resolve generation capacity – customer load mismatches. Ultimately, we believe that integrated, end-to-end bidirectional information/communications technologies ("ICT") solutions, using logic-based, big-data grid analytics and advanced predictive technologies, will be key to the success of the 21st century power system. In particular, combining the different and complementary characteristics of distributed generation such as CHP and/or solar with energy storage, demand response and distributed intelligence will be essential in increasing the value of variable output generation in the energy market. Both wholesale and retail markets must adapt to these innovations, not only for individual DERs but also for their many likely combinations. [Finding No. 8]

Prosumerization of the Electric Grid and Transactive Energy

A recent trend, which is a key result of the proliferation of DERs, is the "prosumerization" of the electric grid. Customers are evolving from more passive and deterministic consumption patterns to more active ones, managing the supply and delivery of electricity through a more transactive environment. What are the implications of this trend on both retail and wholesale markets?

Figure 2 – Prosumer-Grid Evolution



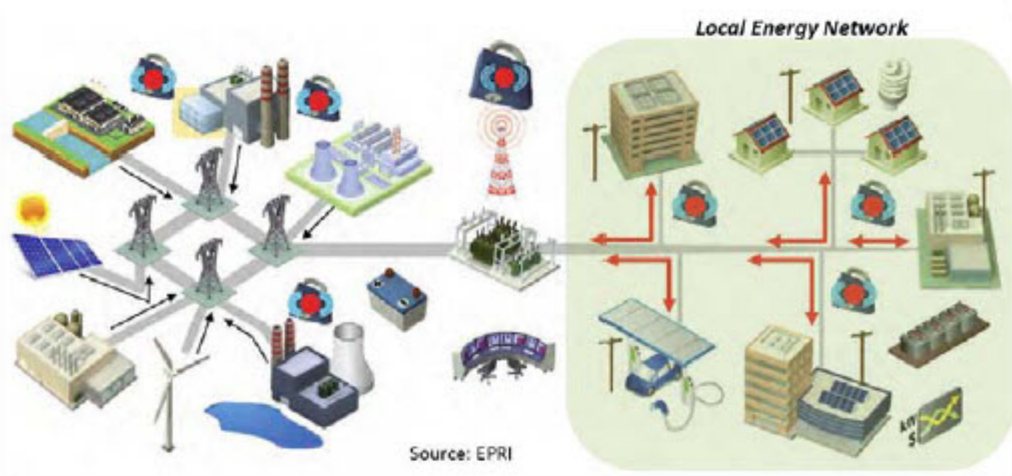
(Martini, 2013)

Transactive energy, which many industry analysts predict as forming the long-term underpinning of the 21st century power system, refers to the use of economic transactions to coordinate distributed energy resources to meet multiple generation, transmission and distribution objectives. It accomplishes that coordination using information regarding economic value across balancing markets and distributed grid-control systems, which results in the exchange of value signals among all participants, including customers.

The Emerging Smart Grid and the Integration of DERs

The following is a depiction of the emerging smart grid and the integration of DERs from the point of view of the customer.

Figure 3 – DR 2.0 The Future of Customer Response



(Martini, 2013)

DER technologies are considered disruptive by many electricity-grid stakeholders and have the potential to fundamentally change the marketplace. The potential DER threat cycle is as follows: lost kWhrs for utilities and stranded cost recovery unless rates increase; rate increases, in turn, incentivize the use of more DERs; and wholesale markets slow to align market rules, which may not appropriately compensate DERs. Perhaps the biggest challenge is that, while a wide variety of potential grid services have been identified, clear definitions of those grid services, and specific utility incentives and tariffs and ISO market rules to monetize DER benefits to the grid, have not been specified, much less implemented.

Interest in microgrids has accelerated; microgrids, enabling a simple to complex "building block" approach to balancing supply and demand, are viewed as a type of electric distribution system containing loads and a combination of DERs downstream of a substation that can be operated while connected to the main power network or while fully islanded.

There is a wide range of types of microgrids, from on-site, fully islandable solar storage to a campus environment with numerous types of generation and DER assets. The first of the two following charts represents a list of microgrid technologies, followed by a list of distributed energy resources found in microgrids. Again, the challenge for grid operators and utilities will be to have in place rules that allow for appropriate compensation of the resources.

Figure 4 – Microgrids and Distributed Energy Resource Management Software

Technology category	Examples
Dispatchable generation technologies	CHP, fuel cells, microturbines with heat exchangers, diesel gensets, utility grid energy purchases
Intermittent/limited generation technologies	Wind, solar (PV and thermal), biogas/biomass, hydropower, heat pumps (air/ground)
Demand side technologies	Absorption chillers, absorption refrigeration, natural gas chillers and boilers, lighting and office loads, other HVAC loads
Storage technologies	Batteries, flywheels, super-capacitors, thermal (precooling/preheating buildings)
Control technologies	Demand response, discrete load management, islanding switches, smart meters, solid-state power electronics, capacitor banks, Volt/VAR injection devices, storage technologies

Supply type	Description	Financial Value	Operational Value
Uninterruptible Power Supply	Intermittent generation to avoid power interruptions associated with grid outages.	Avoid financial losses associated with power interuption.	Significant increase in reliability.
Combined heat and power (CHP)	Base load generation AND thermal.	Offset electrical use, thermal use and demand charges through more efficient use of fuel's energy.	Significant increase in reliability.
Fuel cells	Base load generation.	Offset electrical use, thermal use and demand charges.	Significant increase in reliability.
Solar	Intermittent Generation (during day-time).	Offset demand charges during the day and electrical use, SRECs.	Decreases system reliability and introduces power quality issues.
Batteries	Firm generation, can be stationary or mobile (electric vehicles).	Reduce demand charges, subsidies.	Significant increase in reliability.
Geothermal or biomass	Base load electricity generation AND thermal applications.	Offset electricity use, thermal power demands and RECs.	Significant increase in reliability.
Demand type	**Description**	**Financial Value**	**Operational Challenge**
Load shedding: capacity program	Offerings in reduction in capacity when called.	Payment based on capacity qualified: represent the bulk of demand response markets to date.	Must reduce capacity when called.
Load shedding: Emergency Interruptible programs (EI)	Offering to reduce load during grid emergencies.	Payment based on capacity and energy reduced.	Limited since only called when there is a grid emergency.
Ancillary service markets	Offering energy and capacity into the ancillary service markets.	Significantly higher than capacity or EI programs per unit of curtailment.	Requires near real time bidding and curtailments.
Load shifting (e.g. precooling)	Precooling or the ability to shift the load to a non-peak time.	Reduced demand charge, and no fixed price program.	Infringing upon the comfort of building tenants.
Load into supply market	Offering 'negawatts' into wholesale energy market.	Greatest theoretical value, but no enabling regulatory framework yet implemented .	Lack of appropriate DERMS solutions.

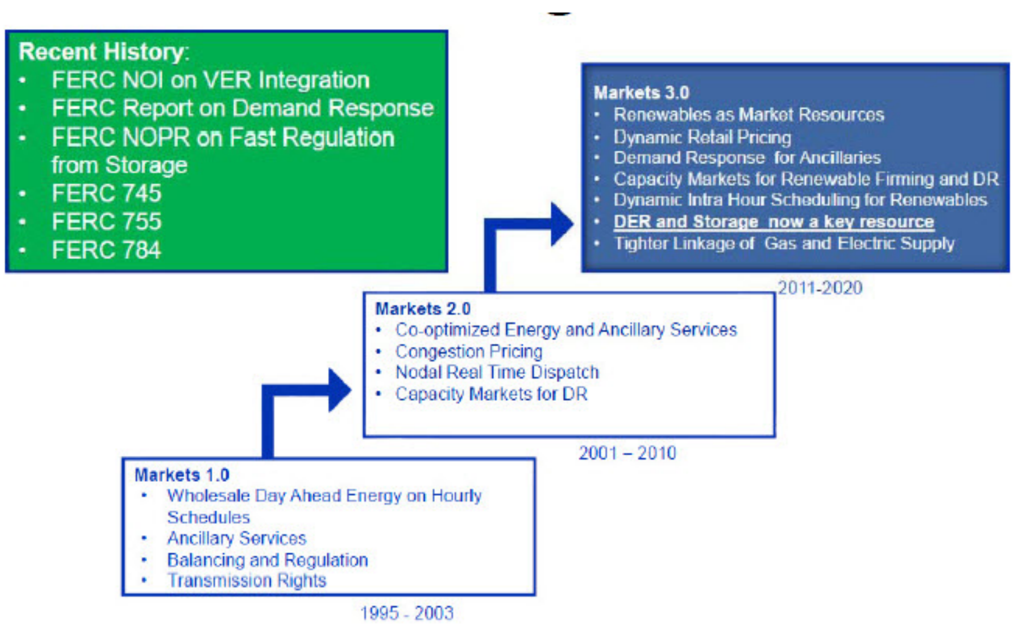
(Saviva, Ap 2013)

FERC Orders Propelling Forward DER Growth

The actual mix of DERs in specific markets will vary and be based on many site-specific, locational factors. However, whether stand-alone or aggregated loads or optimized through microgrids, all resources should be able to capture new, potentially lucrative revenue streams recently enhanced through FERC orders 719, 745, 755, 786, 794, and 1000, as well as state and other related policy incentives as appropriate for the particular geographic area/location. The expanding role of responsive-demand resources is particularly seen in markets characterized by volatility, high demand peaks and a lack of new transmission-level generation capacity. In some other areas, microgrids are seen as the ultimate reliable DR resource since islanding securely takes load off of the utility grid. VPPs are sometimes used interchangeably with microgrids, with VPPs allowing the tailoring of electricity supply and demand services for a customer or customers, maximizing value for both the energy user and distribution utility through software innovations and robust digital energy networks and access to wholesale power markets (peak capacity, economic energy and grid regulation services).

NECHPI believes that wholesale and retail electricity markets are converging as a result of the increasing presence of DERs on the grid. (Finding No. 9) The following is a depiction of the market evolution of this convergence:

Figure 5 – Markets 1.0, 2.0, 3.0



(Martini, 2013)

Requirement for Increase in Both Demand- and Supply-Side Flexibility Options

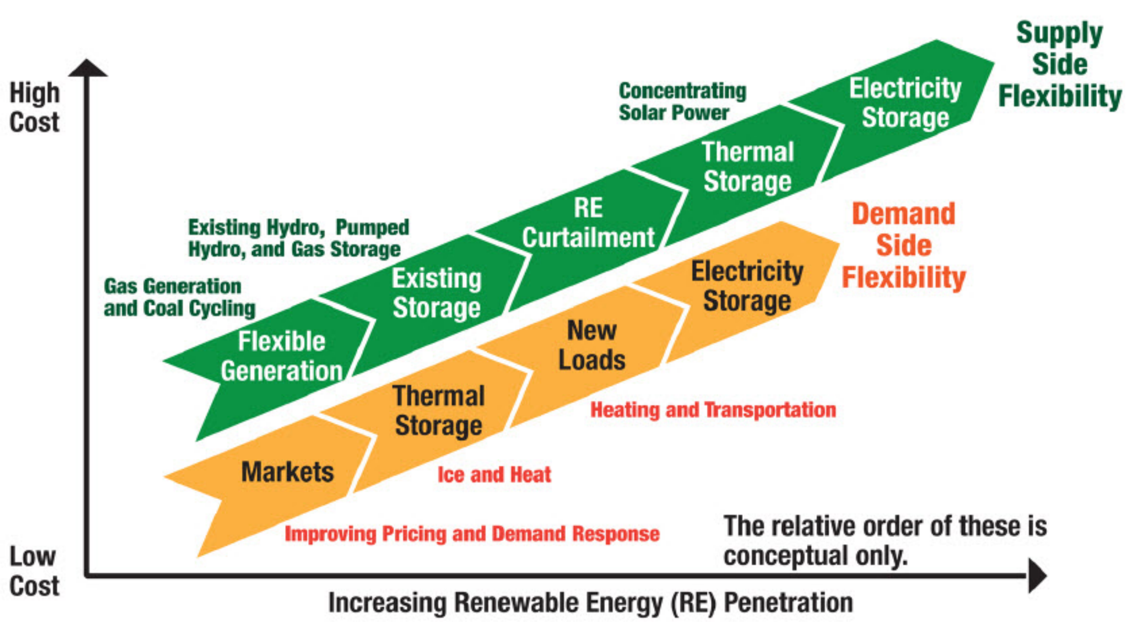
There is a significant need for a dramatic increase in both demand- and supply-side flexibility options in order to ensure that the grid maintains its reliability and power quality. System flexibility can be increased using a broad portfolio of energy resources:

- Flexible generators;
- Dispatchable resources such as some CHP;
- Demand resources such as interruptible loads;
- Demand-side management grid services (regulation, contingency, flexibility, energy, capacity, ramping);
- Controlled charging of electric vehicles;
- New transmission infrastructure;
- Geospatial diversity of the variable resources to smooth output; and
- Coordination of bulk power system operations across wider geographic areas.

All of these flexibility options should be employed and compensated for their contributions to the balancing and reliability of the grid.

The following chart demonstrates the range of grid stability services able to be provided by various distributed resources. Generation, Storage and DR can each provide unique services as well as those in common. As the market evolves, the question of which resource is best suited to provide which services will depend on certain market characteristics and what financial benefits are available (e.g., wholesale market rules, utility tariffs and available incentives and so on).

Figure 6 – Increasing Renewable Penetration



(Denholm, Jul 22, 2013)

Energy Storage as a Rapidly Emerging DER

Energy storage in particular has different cost/benefit profiles on a market-by-market basis. NYSERDA has studied this in New York State. (Brown, 2007) In general, EPRI has constructed a storage end-use potential benefits framework as follows:

ISO Markets

- Frequency regulation
- Spinning/non-spinning/supplemental reserves
- Ramping
- Black-start services
- Real-time energy balancing
- Energy-price arbitrage
- Resource adequacy

Variable Energy Resource Generation

- Intermittent resource integration: wind (ramp/voltage support)
- Intermittent resource integration: solar (time shift, voltage sag, rapid demand support)
- Supply firming

Transmission/Distribution Support

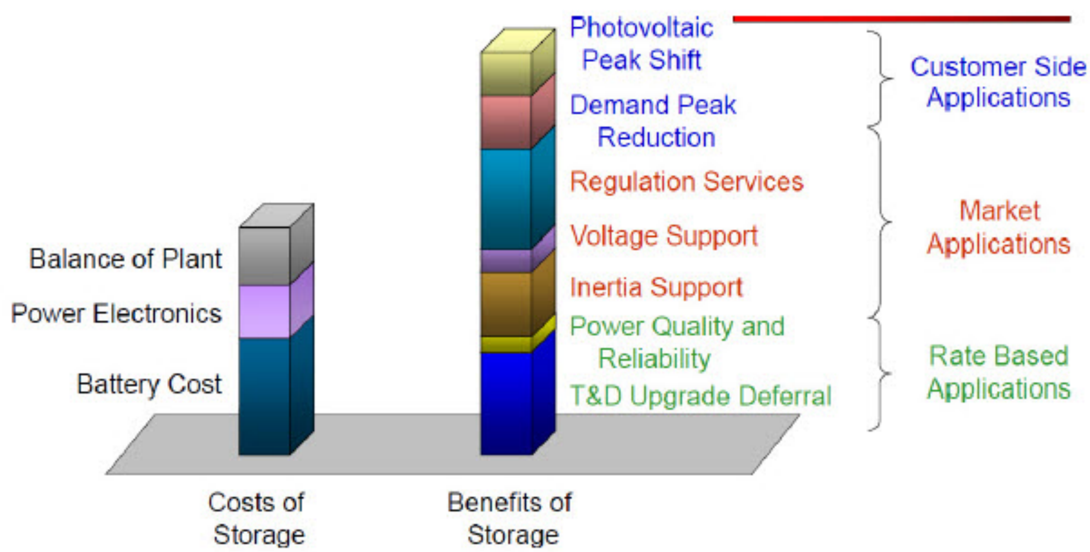
- Peak shaving: off-to-on peak energy shifting (operational)
- Transmission peak capacity support (upgrade deferral)
- Transmission operation (short-duration performance, inertia, system reliability)
- Transmission and distribution congestion relief
- Distribution peak capacity support (upgrade deferral)
- Distribution operation (voltage support/VAR support)
- Outage mitigation (e.g., microgrids)
- Energy surety/backup power
- Renewable energy integration

Customer/Behind-the-Meter

- Time-of-use/demand charge bill management
- Power quality
- Peak shaving (demand response)
- Time shifting (optimizing energy costs)
- Back-up power (UPS+)/business continuity
- Retail rate optimization

Critical to the economics of energy storage is the bundling of the most feasible and highest priority bundle of storage options providing the highest value. Depending on the market, some benefits have not yet been monetized or are highly site-dependent. The following shows the applications available but the benefits may vary greatly (EPRI).

Figure 7 – Electricity Storage Utility Applications



(Kamath, Sep 13, 2013)

Another key problem is that many of the above-listed "theoretical" benefits are still not compensated in most wholesale markets. The following is a list of services currently provided (in green); those provided in some markets (in yellow) and those not yet provided (in red) but deemed critical to the success of DERs.

Figure 8 – Successful AB2514 Procurement Target Evaluation

(California Energy Storage Alliance, Jan 14, 2013)

NECHPI believes that CHP and energy storage represent DERs that have the most difficulty finding their established places in both retail and wholesale markets, though for very different reasons. CHP has a history, most particularly with utilities, which has not been altogether positive, and we believe this on-going issue has resulted in low participation rates in wholesale markets and has negatively affected how it is compensated in both wholesale and retail markets. Coupling Energy Storage with CHP (both thermal and electric) offers new opportunities that should not be rejected out of hand because "we don't do that." We further believe that this is the proper time to reassess the tariffs, market rules, regulations and policies that have accreted over time, are misaligned and have resulted in a diminished access to capital, functioning as deterrents to growth in spite of the numerous positives and glowing reports of CHP's renewed role in a resilient, flexible, and reliable grid as critical infrastructure. (Finding No. 10)

Energy storage, on the other hand, is in the spotlight as the next exciting DER solution to many of the grid's existing and emerging problems. Storage certainly has an important role, most particularly as costs come down and multiple revenue streams become available to it. However, storage is still an undefined resource in many ways, and its ability to provide services at the distribution, transmission and behind-the-meter levels across a wide range of services has caused definitional problems for many grid operators and utilities. These issues are still unresolved.

Two Key Aspects of Integrating DERs with Wholesale Markets

There are two key aspects to integrating DERs with wholesale markets and grid operations worth mentioning. One is the impact of DERs on the grid's physical stability. The second is the effects of price-responsive DERs on wholesale market behavior. These are two very different issues, and have varying implications for wholesale operations visibility and retail-level interactions. In addition, not all DERs have the same impacts, such as CHP, which has some characteristics most in common with traditional generation sources than other DERs but, in contrast, are located close to loads. If DERs become a substitute for conventional generation which provides inertia and governor response, the question arises whether the grid will have enough of inertia and governor response resources at higher levels of renewable energy, which, because of NERC rules, are not able to provide those resources.

In particular, concerns have been raised whether, at higher levels of penetration of renewables and DERs, NERC performance criteria can be met or whether maximum frequency deviations on large unit outages can be managed. In addition, if renewable generation displaces more than 50% of conventional generation in terms of capacity, there may be less than apparent total headroom available from conventional generation for primary or governor response and for automated generation control or secondary response. In other words, primary governor response may eat into the capacity that was thought available for spinning reserves.

At the other end of the spectrum, one of the major advantages claimed by the new generation of smart-grid technologies is that on-site loads will be able to respond to energy prices autonomously. This raises the issue as to what will be needed in terms of regulatory and tariff structures allowing end users/loads direct access to day-ahead, hour-ahead, or real-time energy prices from the wholesale market. However, price-responsive loads having direct access to wholesale markets can also result in substantial price instability. Simply put, if the demand side is more elastic than the supply side, the prices in the sequential price-responsive market begin to diverge. Without the different time dynamics of generation and load taken into account if load is faster than generation, there will be substantial problems in wholesale markets. Essentially grid operators will need short-term and day-ahead load forecasting that incorporates the effects of load elasticity.

The following represents an excerpt from (NREL, Oct 2013). Bridging opportunities between wholesale markets and emerging DERs has the potential to provide many benefits to the grid, including reduction in costs, improvements in grid stability, minimizing grid congestion and line losses, etc. The distinct characteristics of each of these resources present challenges, however, in ensuring that they have non-discriminatory access of wholesale markets. For example, deployment of distributed generation such as CHP can provide very positive and substantial impacts on wholesale market operations. In Denmark, CHP plants are required to participate in wholesale power markets, and a third of the plants also participate in real-time energy markets. In contrast, solar PV rarely participates in wholesale markets but has an indirect effect by reducing net demand levels during mid-day hours, hours that represent peak price hours.

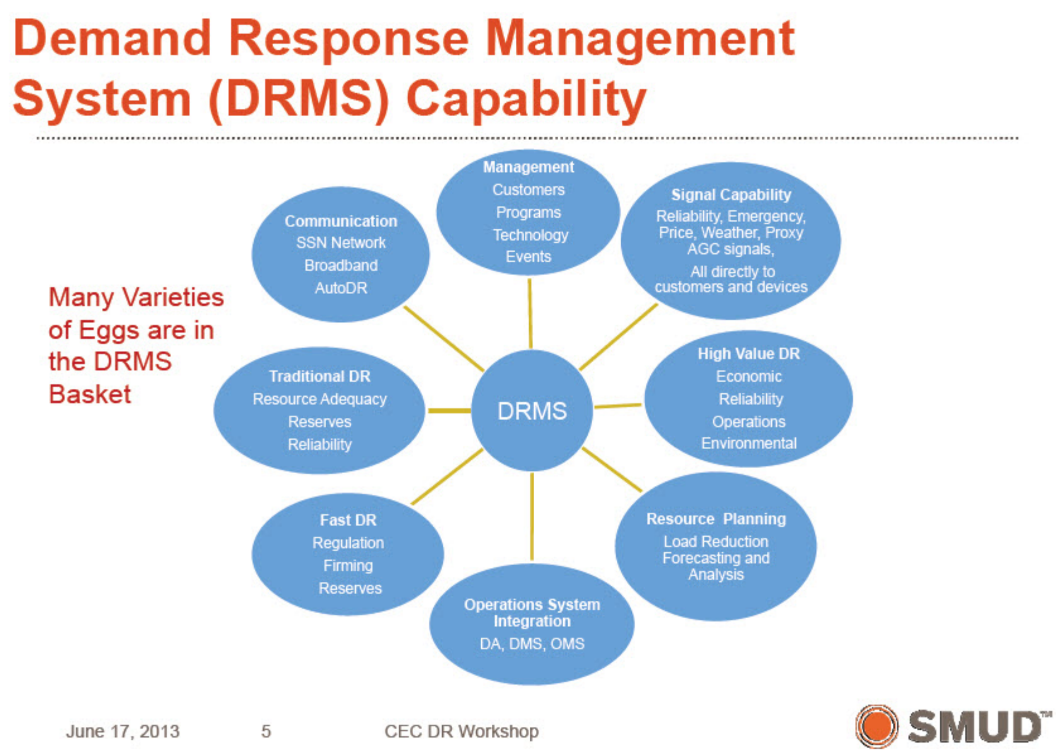
Thus, NECHPI fully realizes that given each DER's unique characteristics, there will likely be no single approach to integrating DERs into market design. Instead, local contextual and site-specific factors will figure prominently in market designs that result in the coordinated deployment of centralized and *distributed energy resources, as well as in the treatment of hybrid market actors such as microgrids, which represent a combination of DERs, including CHP. (Finding No. 11)*

Energy storage promises to ease concerns over renewable-energy integration and system impacts and to decrease the use of curtailment. Yet, significant policy and regulatory barriers make it difficult for storage to participate in centralized markets. For example, storage can provide generation, transmission and distribution benefits, but in many markets, storage can only be classified and valued as one type. Solutions that would allow the owner of a storage resource to disaggregate these various services and sell them each to a third party for transmissions in markets could induce more optimal use of storage options.

Demand-response management is another DER that has undergone rapid change and includes a wide range of capabilities. Even the definition of demand response has changed. Originally it was defined as changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. Demand response is now viewed (RAP, 2012) as customer loads that can be modulated up or down in real time in response to wholesale market conditions, expressed either in wholesale prices, via frequency or voltage fluctuations or through arrangements allowing direct control by the system operator or third party aggregator.

Sacramento Municipal Utility District, a leader in the implementation of DERs in its electric grid, has focused on integrating "new" DR to many of its business systems, with capabilities to deliver high-value resources by providing rapid response and communicating real-time price and control signals. The following depicts the multi-functionality of SMUD's demand-response management system (DRMS), integrated with both retail and wholesale systems.

Figure 9 – Demand Response Management System Capability



(Coomes, 2013)

Efficiency and DR have many benefits that need to be integrated into resource planning and represent key resources for both wholesale and retail markets.

New Models Emerging for Valuing the Costs and Benefits of DERs

NECHPI's Policy/Regulatory Committee has evaluated various approaches to valuing the costs and benefits of DERs and has found the above-used definition of Rocky Mountain Institute ("RMI"), as a third-party independent evaluator, very useful. [Finding No. 12] RMI has approached the subject matter in a highly disciplined, systematic manner, allowing the formation of standardized, transparent processes, procedures and metrics to evaluate each DER in specific, quantifiable terms. While the analysis is still in its early stages and has focused on solar PV on a preliminary basis (because most of the historical analyses to date have focused on solar PV), we believe that RMI is putting in place a robust, independent means of assessing and then monetizing each individual DER, to enable grid operators, utilities, regulators and other stakeholders to have a bona fide means of developing market rules, pay-for-performance incentive structures and next-generation utility tariffs specific to DERs.

From a grid operation point of view, all of these resources share one outcome – they reduce or shift the load (including both energy and peak capacity elements) that the grid must serve to customers. DERs have vastly different physical, operational and economic characteristics than conventional power plants (as well as to each other) and have created potentially significant misalignments when they are added to a system designed for decades around characteristics of conventional power plants. For example, CHP shares some important characteristics with other DERs while still being a dispatchable source of baseload energy.

There is a growing body of work that has begun to provide needed analysis and quantitative rigor to support the technical viability of integrating significantly higher amounts of renewable energy and energy efficiency to power the U.S. electricity system. However, there is comparatively little analysis into the role that DERs could play as part of a future electricity resource portfolio, hindering the ability to understand the true potential for efficiency, demand response and local generation to displace other generation or grid investments at potentially lower cost and/or increased efficiency. Existing modeling efforts have not meaningfully captured the critical performance characteristics and variables that drive the costs and values of integrating DERs into the electric grid. In our estimation, these new models could have a profound effect on the economic value that accrues to DERs, and in particular, CHP. This might actually provide a breakthrough of sorts for CHP on a variety of issues, including rate structures such as demand charges, standby rates, compensation for various grid optimization/support services and so on.

California can serve as a model for beginning to define several of these energy resources. In July 2013, the California Public Utility Commission ("CPUC") issued a loading order for resource adequacy that requires utilities to procure capacity in the following priority order: energy efficiency/demand response (including CHP), renewable energy, fossil fuels and for the first time, energy storage. It is also opening up the integration of a variety of DERs and has some of the most innovative and supportive programs for CHP in the country, including financial incentives. (CEC)

As mentioned above, the Rocky Mountain Institute, in addition to its specific analysis on quantifying the costs and benefits of solar PV and other DERs, has also developed the Electricity Distribution Grid Evaluator (EDGE) model, which provides an analytical basis for the assessment of the costs and values created by all resources (including CHP), from the perspectives of five key stakeholder groups: utilities, traditional customers (non-participating), participating customers (e.g., customer-generators), third-party service providers, and society in general. The EDGE model incorporates the principal drivers of value in electricity system planning and operations – location, timing and controllability, which are then integrated over multiple timescales (e.g., sub-hourly distribution), bulk power dispatch and annual resource portfolio planning, subject to constraints (regional supply limitations, operational limitations and specific policy requirements such as an RPS).

In NECHPI's estimation, RMI's approach is an excellent justification as to why CHP should be treated on an equal footing with other DERs and even given precedence in some cases (e.g., for critical infrastructure and resiliency). [Finding No. 13]

Benefit and Cost Categories of DER

Broadly, the benefit and cost categories that RMI is aiming to quantify include the following:

- Energy
    - Energy
    - Energy losses

- Capacity
    - Generation capacity
    - Transmission and distribution capacity
    - DER capacity
- Grid Support Services
    - Reactive supply and voltage control
    - Regulation and frequency response
    - Energy and generator imbalance
    - Synchronized and supplemental operating reserves
    - Scheduling, forecasting, and system control and dispatch
- Financial Risk
    - Fuel-price hedge
    - Market-price response
- Security Risk
    - Reliability and resilience
- Environmental
    - Carbon emissions
    - Criteria air pollutants (Sox, NOx, PM10)
    - Water
    - Land
- Societal
    - Economic development (jobs and tax revenues)

After analyzing a wide array of already-undertaken cost-benefit studies and analyses surrounding solar PV (which historically have generally been undertaken either to support or debunk net metering benefits), RMI states that the most significant methodological gaps today include defining distribution value; grid support services value; and financial, security, environmental and social values. It also concluded that because the rate structures and incentives (i.e., net metering) originally designed to stimulate the early adoption and scale-up of DERs (most particularly solar PV) are increasingly under fire and are expected to become problematic as DER adoption rates increase, RMI is focused on evaluating and quantifying any number of other incentives strategies to respond to and support a shifting electricity market (e.g., shared savings, performance-based earnings, innovative rate structures, etc.).

Much of the current discussion and analysis on the costs and benefits of distributed generation has, up until this point, surrounded solar PV, and in fact, the net metering dialogue, the current disputes and the evolving alternatives to net energy metering or NEM (such as the Austin Solar Value Tariff and the Minnesota Standard Offer) are almost entirely a result of solar PV's dominance of the DER "conversation." The EDGE model, while its comparative analyses recently done on studies available are exclusively focused on solar PV (showing their glaring limitations), the intent of the model is to quantify over time the costs and benefits of each DER to ensure that the transformational changes occurring in the U.S. electricity sector as a result of the increasing role of distributed resources are based on sound policy and supported by clear and quantifiable results. DERs are also leading to a shift in the fundamental business model paradigm of the industry, from a traditional, one-way value chain to a highly participatory network of interconnected business models at what is referred to as the "distribution edge."

NECHPI believes that this confluence of factors will likely drive increased adoption of the full spectrum of renewable and distributed resources, including CHP, requiring a detailed understanding of DERs' benefits and costs in the context of a changing system. From this point, rational pricing structures and business models can be better aligned, enabling greater economic deployment of DERs and lower overall system costs for ratepayers. [Finding No. 14]

Utility Rate Structures

RMI's Approach Appears Influential to the Public Service Commission

RMI also discusses utility rate structures in the context of the rapid growth of DERs and believes that existing rates and incentives fail to provide accurate economic signals to align distributed generation investment with system costs and benefits over the long term. It further argues that they need to more accurately reflect the costs and values associated with each particular resource, which in its estimation will require some degree of price unbundling (i.e., charging separately for different cost components). The goal of any new pricing structure should be to ensure that customers pay fairly for what they use and receive fair payment for what they provide. In addition, given the right price signals, distributed generators can adapt over the long term to provide new sources of value to the utility system, which will still have a critical and valuable role as enables and integrators in the deployment, operation and maintenance of distributed resources.

To fully adapt to this new role, utilities must be able to develop new ways of pricing the "network services" they provide and of promoting value creation through distributed-resources development. RMI offers two approaches for utilities to move toward for achieving this: 1) an incentive regulation approach that would allow the utility a more expansive role in managing and, potentially, investing in distributed resources as a tool for reducing costs and 2) a network utility approach under which the utility would provide highly differentiated price signals to incent customers to provide the highest value energy supply, load management, or ancillary services to the utility system.

Finally, we also like RMI's approach because it addresses utility issues of lost revenues, rate structures, avoided costs, etc. head-on and provides some recommendations of how utilities should participate in the distributed energy environment. RMI makes specific proposals on how to reduce disincentives and reward performance with respect to distributed resource deployment, including new pricing models and methods of cost allocation to realign resource investments with system costs and benefits over short-term (operational) and long-term (planning) horizons. Examples include unbundled pricing for reliability, standby, and power quality services; temporally or locationally differentiated prices for energy or distribution services; price structures that reflect how costs are incurred (e.g., demand-based, fixed, energy-based, etc.) and incentive payments for dispatchable demand response or ancillary services to the grid.

RAP's Recommendations for Regulators To Design Distributed Generation Tariffs Well. **(Carl Linvill, Nov 2013)**

We also recognize the significant set of regulatory tariff issues being discussed by the Regulatory Assistance Project at NARUC'S Winter Meeting February 11. While targeting at State regulation they also should apply to NYISO-level and FERC jurisdiction. (Finding No. 15)

1. Recognize that value is a two way street.
2. DG should be compensated at levels that reflect all components of relevant value over the long term.
1. Select and implement a valuation methodology.
2. Remember that cross-subsidies may flow to or from DG owners.
3. Don't extrapolate from anomalous situations.
4. Infant-industry subsidies are a long tradition.
5. Remember that interconnection rules and other terms of service matter.
6. Tariffs should be no more complicated than necessary.
7. Support innovative business models and delivery mechanisms for DG.
8. Keep the discussion of incentives separate from rate design.
9. Keep any discussion of addressing the throughput incentive separate.
10. Consider mechanisms for benefitting "have not" consumers.

NYISO and the State Need to Work Closely

We view New York State's role as helping to open the dialogue between the Public Services Commission and utilities in the state to begin the evaluation of these alternatives in order to ensure that the underpinnings for the rollout of distributed energy resources are properly valued, supported and integrated with all of the policies and regulations in place or being revised, updated or considered for implementation. In addition, given the convergence of retail and wholesale markets because of the emergence of DERs and a grid driven by customer-driven resources, NYISO and the state's PSC will need to work closely together to ensure that rules and regulations are aligned and function smoothly together to support a rapidly evolving grid. [Finding No. 16]

Observations on Wholesale Markets and DERs

Wholesale markets are clearly in flux. A brief survey of FERC filings by ISOs, various commenters on filings, FERC orders, and counter-comments by ISOs exhibit substantial differences of opinion on how wholesale markets should evolve. This is particularly true in capacity and ancillary-services market filings. Examples include ISO New England's proposed changes to its forward capacity market, PJM's proposed market rules for its demand response program and others.

There are other misalignments or lack of coherence of policies supporting DERs. California has been in the forefront of many of the innovations for supporting DERs. Its recent energy-storage mandate is one example. However, the three large investor-owned utilities in the state are blocking solar-storage projects that seek to interconnect to the grid under the state's net metering program. As of July 1, 2013, there were 667 active incentive applications in the Self-Generation Incentive Program (SGIP) queue, totaling 33 MW of capacity. Of these, 319 applications totaling 10 MW of capacity are for storage paired with RPS-eligible generating facilities, primarily rooftop solar PV installations. Utilities are claiming that these systems could "feed back brown electrons under the guise of solar power" (in other words, store electricity purchased from the grid at low cost and sell it when prices are high). The commission issued in December 2013 an order instituting rulemaking regarding this issue, but as of this date, it remains unresolved. (CPUC, 2013)

Another recent set of initiatives in California is related to demand response and energy efficiency policies. In spite of the fact that they are listed as the first two in the state's resource loading order, their participation in wholesale markets remains abysmal. Thus, the state has begun the process of investigating the reasons and then reorganizing markets to encourage the participation of these resources at the appropriate and required levels. This is yet another example of the misalignment of policies and market rules and in a state known for innovation in clean tech policies. It should also be noted that part of this re-examination will more exactly define each resource and to ensure that these definitions are applied across all programs, which has not been the case in the past. Even though CHP policies in California have been on strong paper, this definitional issue has affected it in subtle and not so subtle ways.

Impact of Variable Energy Resources on Wholesale Markets

Various industry research and consulting organizations are recommending changes in market rules for energy, capacity and ancillary services markets, primarily driven by the rapid increase in power production from variable renewable-energy sources. Reliable electricity supply requires that energy demand and energy supply be precisely matched in real-time. There is a corollary need for the system to have enough quality of "capacity" (that is, physical capability to produce electricity mechanisms, measured in quantity of Watts) to meet the maximum expected demand ("peak"). Capacity mechanisms are employed in many deregulated markets to ensure that the electric grid has sufficient capacity to meet peak demand. However, the reliability challenges of the power system are changing, with a rapidly growing share of renewable energy sources, requiring that the capabilities of this physical quantity of capacity also need to change.

The Regulatory Assistance Project ("RAP") has done significant analysis on today's traditional capacity mechanisms and argues that these traditional mechanisms are not designed to elicit the operation or investment in capacity with the flexible capabilities that will be required with increasing frequency, and at multiple times of the day or year, as the share of variable renewable-energy-sources ("RES") in the power mix increases. RAP's arguments are detailed and well-documented and not appropriate to go into detail here and involve analyses of available resources (baseload, intermediate load, peaker plants), bidding and pricing mechanisms, procurement policies as well as many other factors. The key conclusion is that the traditional approach to resource adequacy, no matter what the current design characteristics, is no longer fit for the purpose. In particular, RAP concludes that the current approach of providing the same remuneration to all firm capacity providers no matter what the nature or capability of the resource is insufficient to maintain the reliability of the system.

Thus, "the increasing shares of variable RES mean that net energy demand – that is, total demand minus the virtually 'free' energy available from renewable sources – is becoming much more challenging to anticipate and serve over all timescales. Therefore, a high degree of flexibility within the portfolio of dispatchable resources is therefore called for – generation, demand response, and/or energy storage – that can increase or decrease rates of energy supply and demand at steep gradients ("ramping") and repeatedly over time ("cycling") in order to "flex" around the availability of variable RES and so to meet both net energy demand and resource adequacy targets in the most cost-efficient manner possible." (RAP, October 2013):

RAP further concluded that the type and quantity of balancing and ancillary services required to ensure system reliability will also change and that the greatest increase in demand with rising share of RES will not occur with the fastest services (such as primary reserves or frequency regulation); rather, the services that will be in greater demand will be those that can respond within minutes to tens of minutes to hours and offering the following capabilities

- Flexible, fast start-stop cycling capability: the ability to shut down and re-start, or cycle, a resource multiple times within a reasonably short window of time and up to hundreds of times over the course of the year;

- Regular, dispatchable ramping capability: the ability to reduce a resource to a low level of stable operation and ramp it back up at a specified rate, not in a traditional operating reserve role (e.g., under contingency conditions) but as a normal-course ramping capability; and

- Ramping capability reserved now to be used in the future: a slower type of secondary reserves with flexible ramping capability, a type of ramping service, which can address issues arising in the tens of minutes (e.g., due to forecasting error).

NECHPI believes that many existing plants can be retrofitted with technologies to improve operational flexibility performance, including some CHP plants. In addition, other DERs, such as large pools of aggregated demand response, especially when combined with storage options, can provide low-cost, bi-directional flexibility on the demand side that can also be valuable in integrating variable renewable energy, particularly when compared to traditional, centralized generation. [Finding No. 17]

RAP has proposed several intriguing new market designs in response to the challenges of increasing levels of RES: 1) a "tranched" capacity mechanism; and 2) an enhanced forward services market.

- A tranched capacity mechanism is an "apportioned, multi-staged capacity approach where, instead of a uniform clearing price paid to all capacity resources, there are three different values paid for resources, determined based on the capabilities of the resources offered. The first tranche represents the most highly valued flexible resources, which are paid at the highest level, followed by the second tranche, representing flexible, mid-merit resources also required to reliably meet forecasted net demand and finally the third tranche, "plain vanilla" firm capacity with the least value when all firm resources compete for a relatively small quantity.

- An enhanced forward services market approach is an adaptation of the existing ancillary/balancing services markets through the addition of new products or services (e.g., ramping, cycling) as necessary, enabling full participation of the demand side and by introducing longer term investment timescales for revenue payments through forward auctions. An advantage of this approach over a capacity mechanism is that rules can be fairly easily adjusted to reflect improvements in the operation of energy-only markets.

Several ISOs have already moved in the later direction. CAISO is evolving its services market along the lines of the enhanced forward services model, incorporating the three capabilities listed above. It has already implementing a ramping product, as has MISO.

ERCOT is proposing significant changes to its ancillary services program. It is recommending five new ancillary services products, plus one addition product that would be used during some transition period:

- Synchronous inertial response service (SIR);
- Fast Frequency Response Service (FFR);
- Primary frequency response service (PFR);
- Up and down regulating reserve service (RR);
- Contingency reserve service (CR); and
- Supplemental reserve service (SR), during a transition period

While not all of these are new, they represent a new combination of services required to meet the increasing penetration of RES on ERCOT's electric grid. Some of these proposed services are listed on the chart of grid services not yet compensated by wholesale markets and represent new directions in the evolution of market rules supportive of DERs.

CHP Participation in Energy, Capacity and Ancillary Markets

NYISO manages energy, capacity and ancillary services markets. The capacity market is designed to ensure that sufficient capacity is available to reliably meet New York's peak load periods and its planning reserve margins. This market provides economic signals that supplement the signals provided by NYISO's energy and ancillary services markets. In combination, these three sources of revenue provide economic signals for new investment and retirement decisions, and participation by demand-side management resources. It is impossible to go into detail here given the sheer complexity of the markets, as well as the differences in market design between ISO/RTO markets within the U.S. Suffice it to say, each market has a different market structure and system requirements for handling regulation, load following and unit commitments, which ultimately has implications for CHP and its role in the NYISO market.

In summary, NYISO operates a multi-settlement wholesale market system consisting of financially-binding day-ahead and real-time markets for energy, operating reserves, and regulation. Through these markets, the NYISO commits generating resources, dispatches generation, procures ancillary services, schedules external transactions, and sets market-clearing prices based on supply offers and demand bids. The NYISO also operates markets for installed capacity and transmission congestion contracts.

In a general way, excess power sales could provide additional revenue streams for a CHP project, helping to make it more economically viable as well as achieve state energy goals. We believe there are four types of programs that can provide for excess power sales:

- Programs based on state implementation of the federal PURPA. States have significant flexibility in administering PURPA, though FERC has limited its applicability, particularly for facilities larger than 20 MW. (However, FERC recently ruled that CA's multi-tiered avoided cost rate structure for a FIT for CHP systems of up to 20 MW is consistent with PURPA.) Successful implementations of FIT programs include:
    - Technical criteria for CHP eligibility;
    - Use of standard contracts and pricing; and inclusion of locational adders for avoided T&D investment;
    - Net metering programs;
    - Competitive procurement processes. Certain states such as California have used these processes to acquire larger CHP projects.
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In restructured/deregulated states, which New York State is, CHP projects theoretically should be able to bid into energy markets as well as capacity and ancillary service markets, depending on the CHP facility's operational characteristics and the requirements of the particular market. RTOs/ISOs administer and manage these capacity and ancillary services markets. Demand reduction that includes CHP should be able to participate in these markets depending on size, and metering, performance and registration requirements.

State utility regulators have the ability to influence market rules to encourage the participation of distributed energy assets. There are several opportunities for this influence on rules that have an impact on CHP, including metering requirements and meter cost, and planning (ensuring the balancing authority knows about CHP and includes it in their planning).

Increasingly, industry analysts believe that market rules with respect to the provision of various ancillary services and potentially capacity could have a significant impact on how increasing amounts of renewable power are handled and supported economically. The services required to reliably transport electric power from seller to purchaser, given the requirements of the interconnected transmission system, are referred to as "ancillary services" and include scheduling and dispatch, reactive power and voltage control, regulation, resource reserves and non-spinning reserves. Since the fluctuations of power generation from wind and solar resources can occur very rapidly, the resources best suited to balance renewable energy tend to be gas-fired power generators and, increasingly, demand resources and longer term, energy storage. Microgrids that incorporate distributed generation are also technically capable of providing ancillary services.

The market design of ancillary services can have a substantial impact on the mix of natural gas, distributed energy resources and renewables (including the degree to which increases in ancillary services needs caused by increasing levels of intermittent renewable generation are met by natural gas as opposed to other technologies). A strengthening of ancillary services and associated revenue streams should favor natural gas, in particular relative to coal-fired power generation. This is because gas-fired power generation, because of its greater relative flexibility, can participate more fully in ancillary services markets than coal-fired generation can.

Current CHP participation in capacity, reserves and ancillary services markets is very low across the U.S. Reasons for low participation include the highly complex and specialized nature of the markets, with detailed rules to ensure that the electric system remains safe and reliable and that CHP operating characteristics may not align with participation requirements because of sizing issues. If there is no export capability, participation in capacity markets is precluded. CHP could participate in ancillary services markets if operational flexibility is designed into the system (e.g., the CHP system is sized with single or multiple prime movers that provide excess capacity when needed or the system can operate during times when the thermal load is predictably lower, affording excess electrical generation to be available). CHP systems with a synchronous generator or a generator with a power electronic interface have the advantage that they can be controlled to provide or absorb reactive power.

Explicit inclusion of CHP in capacity, reserves and ancillary markets is a key measure by state regulators to achieve resource adequacy, energy efficiency and GHG reduction goals. The market for third-party balancing services and local voltage support is also growing, and FERC is promoting robust competitive markets for the provision of ancillary services from a variety of sources. State support of these policies could provide additional revenue streams of key importance to CHP's economic viability and attractiveness to investors.

NYISO is currently not an attractive wholesale market for CHP

NYISO is currently not an attractive wholesale market for CHP. NECHPI is very concerned about this. Enormous amounts of existing and potential CHP remain under-utilized. [Finding no. 18]

Wholesale-market access can greatly enhance the cash flows of clean-energy projects and thus, their financeability, and CHP in particular should be able to derive benefits today along with other DERs. However, *CHP participation in NYISO wholesale markets has decreased over the last three years because of changes in certain market rules, and NECHPI feels strongly that the ability to participate in the range of wholesale markets could greatly increase CHP's attractiveness to financing sources, in addition to Green Bank support. [Finding No. 19]*

CHP is currently excluded from participating in NYISO capacity and energy markets and is only able to participate in the 10-minute non-spinning reserve ancillary-services market (not the regulation, spinning reserves or black-start markets). This is in contrast to both solar PV and wind where special products (though limited) have been developed to allow them to participate in NYISO capacity markets. Access to these revenue streams would greatly enhance CHP's financeability.

In terms of ancillary services, NYISO's reading of NPCC requirements states the following:

The reliability rule in New York limits behind-the-meter generation to non-synchronous reserves and will not allow participation in regulation if there is on-site generation. The requirement comes from an NPCC requirement in A-06 Operating Reserve Criteria (section 3.10.2), not a New York State Reliability Council requirement: (NPCC). The NYISO has recently stated that it does not allow behind-the-meter generation to provide supply in excess of the load of the resource. While we are told that this rule is being reviewed, *NECHPI avers that A-06 Operating Reserve Criteria substantially limits the ability of CHP to participate in and derive financial benefits from the ancillary-services market and needs to be reviewed. [Finding No. 20]*

The state needs to support FERC's efforts to ensure that wholesale power markets support the parity of all energy-resource types on both the demand- and supply sides. Many current market rules do not do so. The various wholesale markets are rapidly converging, and many industry analysts argue that state policymakers must be proactive in bringing together the regulators, utilities and other key stakeholders to bring about the adoption of robust, open markets for all resources.

FERC is designing markets to provide fair access, broad participation and performance compensation for "smart" technologies that modernize the grid for efficient, reliable use through the adoption of industry-consensus reliability and smart-grid standards and the promulgation of rules supporting their adoption.

Recent FERC decisions are providing the needed justification to compensate distributed Qualifying Facilities ("QFs") to compensate distributed QFs for value provided based on such things as locational benefits rather than solely based on the utility's avoided cost of producing the next incremental unit of electricity. These new rulings could provide an approach to facilitate DG growth and would help drive investment in high-value DG, particularly DG that may serve local load but may not necessarily service on-site load. This would be extremely helpful for CHP as well as other distributed energy assets. Net metering policies are also important support mechanisms for DG, most particularly solar PV, and we urge New York State to improve its net metering policies across the board.

CHP also has a unique role in its ability to serve not only on-site load but also local loads and could support such configurations as CHP Zones and microgrids if this PURPA value-based approach were in place. Historically, under PURPA, CHP resources were must-take; all of their export generation had to be purchased for a contracted price. However, in some states such as California, this has changed. The amount of must-take energy is limited to that needed for a facility's on-site thermal needs, with remaining capacity able to be bid in the CAISO market. *NECHPI recommends market mechanisms that support new approaches to CHP plant designs, flexibility in contracts and concrete recognition of the contribution of CHP resources to grid system stability and reliability. [Finding No. 21]* It does not necessarily follow that just because a market exists for capacity, energy and ancillary services, CHP projects will be developed and implemented. There must be certainty and risk reduction in place, including long-term contracts. The existing payment mechanisms do not provide this.

We urge the development of policies that allow the design of "oversized" CHP generation for a more dispatchable resource, as an example, and of possibly supporting utility joint ownership with third parties that are in designated locations where the benefits of CHP can be optimized. We believe this will be necessary if the role that CHP plays in the electric grid is to grow. Additionally, that CHP sites serve as *preferred locations to add any NYISO required peaking or black start resources, in that these sites are a more cost effective placement of these assets in that they are continuously active with close supervision and afford avoidance of duplicated siting, permitting, staffing, grid interconnection and other costs. [Finding No. 22]*

The following are some of FERC's orders that we believe clearly support the direction we are proposing:

- Order 745 (March 2011) specifies that demand-response resources are to be integrated into the RTO/ISO energy-market bidding and economic dispatch process to balance supply and demand and to pay the full market price (locational marginal price or LMP) for the service provided.

- Orders 693 (March 2007), OATT Reform Order 890 (February 2007), and Transmission Planning Order 1000 (July 2011) all require demand resources be used to provide reliable, efficient transmission service: use for ancillary services (operating and spinning reserves, regulation and frequency response and reactive power and voltage control) on a comparable basis to generation; resolution of operational emergencies; and planning for a reliable transmission system.

- Order 764: Variable Energy Resources Integration requires generators to provide 15-minute intra-hour scheduling data to transmission providers for power production forecasting

- Order 755: Frequency Regulation Compensation requires pay-for-performance compensation for faster and more accurate response to grid-operator signals to correct frequency deviations.

- Order 794: Third-Party Provision of Ancillary Services and Electric Storage Technologies Accounting (July 2013) facilitates robust, competitive markets for the provision of ancillary services from all technically-qualified resource types, including CHP.

In addition, NECHPI recommends that policymakers in the NYISO help the State of New York enable the PSC to accomplish the following:

- *Expand resource design to include aggregation of multiple locations and zones into a single resource within reasonable limitations.*
- *Allow behind-the-meter wholesale-market participation for CHP, when it is an on-site energy resource.*
- *Establish a workable mechanism for CHP in resource adequacy and long-term procurement processes. As with utilities, NYISO does not include CHP in its loading order or its resource-adequacy and long-term planning processes. This economically disadvantages CHP in a significant fashion.*
- *Going forward, take advantage of FERC's market-driven stances related to DERs and support the development of new market formulations for improved reliability and efficiency and energy/reserve procurement. A new market formulation under development by Sandia Laboratories represents energy and reserve products in terms of standardized contracts whose terms cover a broad range of system service needs, including power increments, ramp rates and energy capacity. These contracts are designed to provide transparent financial instruments for the pricing and procurement of energy and reserves in forward markets as well as blueprints for the physical deployment of energy and reserves in real time. To ensure a level*

playing field, all resources capable of satisfying system service needs, including CHP, can and should submit supply offers for the provision of these needs, regardless of their physical forms.

- *Establish a criteria to account for the efficiency of natural gas utilization, i.e., to avoid the use of natural gas in separate heat and power (SHP) generation where no more than 60% is converted to useful energy, and motivate the natural gas to be used in CHP where it can be converted to as much as 90% useful energy. This ought include an accounting of the CO_2 emissions from the combustion of the natural gas (and the credit for the avoided CO_2 from separate heating or cooling fuel as well).*

NECHPI believes that these changes are not as far in the future as one might suspect. It must happen sooner rather than later. The level of uncertainty in both generation and load is increasing rapidly. The provision of reserve will increasingly involve participation from both the supply and demand sides of the market. Not only will demand-side participation increase, but some resources, such as energy storage systems, will also blur the boundaries between supply and demand.

Further, the uncertainty of generation is increasing as a function of intermittent renewable-energy penetration. The uncertainty of load is increasing as a result of the emergence of demand-response resources. Taken together, this will entail new market designs that are standardized, transparent, and driven by market requirements, including those that are localized. CHP has a critical role to play in the emergence of this new market design but can only do so if it is integrated into NYISO's resource-adequacy and long-term planning processes. [Finding No. 23]

The Relationship between Natural Gas, CHP and Renewables

Gas generation plays an important role to backstop renewables and offers other benefits to the grid. It can be turned up or down quickly; firing up or turning down a natural gas plant takes but a fraction of the time it would to ramp up or down coal, nuclear or other major forms of generation. Gas also lends itself to a variety of scale. Natural gas-fired generation can be sized anywhere from distributed generation of 150 kW or less, all the way up to 800 MWs and larger. Another benefit is that, because they can be built at a smaller scale, natural gas plants can be sited closer to the population base, reducing reliance on larger, longer-distance transmission and providing more operational flexibility.

However, moving the grid to even greater reliance on gas manifests its own set of issues and concerns, ones that will likely present continued issues to potential investors so must be addressed head-on. Some issues include the following:

- The robustness of the gas transportation system and the ability to schedule gas delivery in advance;

- With many more points of generation, particularly if they are along the same pipeline, there can be higher risks that a single contingency or event could affect all of the points at the same time.

- Concerns about interruptions in gas supply;
- Contracting policies that place priority on delivery of natural gas for residential and commercial heating over gas for electric generation (e.g., ISO New England has stated that it experienced significant operational challenges in January and February 2013 and January 2014 based at least in part on demand for heating gas, putting the supply of gas to the grid in question).
- Natural gas and utility industries operating under different regulatory, contracting and operational structures.

Policies for Enhancing Gas-Renewables Complementarity

Natural gas-fired power plants are well-suited for backing up and smoothing out intermittent renewables and providing capacity. Renewable sources cannot be dispatched, i.e., they cannot increase or decrease production at will and in response to market prices. Rather, renewables are "must-take generation," at least currently. Since system operators have to ensure that the sum of all generation matches load instantaneously, this requires balancing fluctuating renewable energy sources with other resources in real time.

In contrast, CHP has all of the benefits of baseload generation, but unlike other baseload sources such as coal-fired and nuclear generation, it can ramp up and ramp down electricity generation output very quickly and can also resume full generation capacity very quickly.

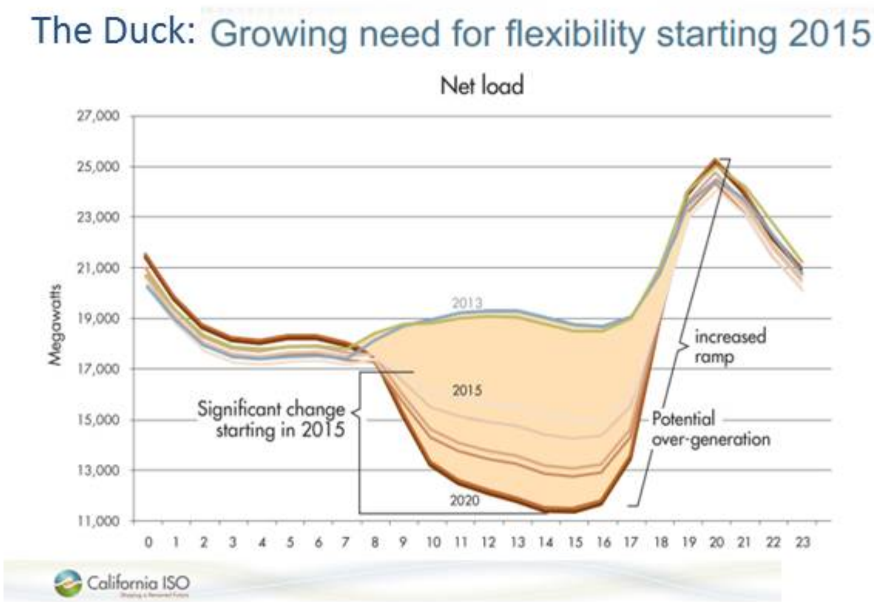
NECHPI believes that if the right contracting mechanisms are in place, projects could in theory be custom-built to provide the services of greatest need to the procuring entity and tailored to the operating environment and operational needs of the utility and RTO/ISO. *(Finding No. 24)*

Natural gas makes a nice complement to renewables in order to back them up and smooth them out in addition to a possible reduction in the need for backbone transmission over time since transmission planning is getting longer and longer and transmission itself more expensive. With networks increasingly becoming real time and distributed, natural gas and renewables are both causes and beneficiaries of such a change. Generation fuels that offer faster deployment and promise a reduced environmental footprint will continue to be popular.

ERCOT, for example, believes that the path to low-carbon generation and grid balancing will likely require the co-development and integration of both gas and renewable resources. However, how the precise interaction of natural-gas-fired and renewable electricity generation plays out over the coming decades depends on several factors, including the price trajectory for both coal and gas, state and federal energy policies, transmission development, market design choices and environmental regulations.

California is quickly facing the need for gird support as more renewables come on stream. CAISO has provided the following graph of the change caused by variables generation, most particularly solar, in the state's grid ramping. CAISO actually refers to it as the growing need for flexibility starting in 2015 to "feed the duck." Officials state that the biggest needs will come when excess wind and hydro create overcapacity, and early sunsets cause solar generation to drop off before peak evening demand periods end.

Figure 10 – The Famous Duck Figure



Both CHP and geothermal capacity are thought to have the ability to move in response to conditions and provide system operators with flexibility and both baseload and ancillary services when needed. CAISO has advocated for a flexibility requirement as part of California's resource-adequacy program, and market mechanisms are designed to drive investor-owned utilities and other load-serving entities ("LSEs") toward procuring more CHP and geothermal. CAISO wants the cost of flexibility to be allocated to LSEs based on their resource mix; requiring those LSEs with large variable generation portfolios to procure flexible generation should help drive the group of distributed resources such as CHP. However, CAISO notes that having the ability to ramp up means holding back generation, so it does mean potentially foregoing revenue. The challenge will be in New York State to extract enough value from capacity, ancillary services and flexibility attributes to compensate for the decline in energy attribute revenues.

The NYISO Electric-Gas Coordination Working Group has reviewed gas-fired generation operating status. Key takeaways included: need for balancing services on the gas pipelines; need to improve management of gas supply contracts including more detailed knowledge about how gas system alerts, OFOs, meter restrictions and balancing agreements impact generator availability, and to promote sharing of generator schedules with pipelines.

It should be noted here, however, that NYISO's recently published Power Trends 2013 did not mention CHP once. In spite of articulated goals to increase the importance of CHP in the mix of generation technologies, particularly in light of the increased state emphasis on resilient energy infrastructure for critical facilities, there are still numerous impediments in place from a policy perspective that reduce the economic viability of CHP projects.

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