Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure: A Summary Analysis of DG Benefits and Case Studies

Final Report Summary
Task #6

Prepared for the

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NOTICE

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1. INTRODUCTION: METHODOLOGY

This Report surveys and synthesizes the findings of four Task Reports examining a set of alternative strategies or business models for deploying distributed generation (DG) as grid support.

The four earlier reports addressed the following topics:

The Benefits of Distributed Generation

Distributed Generation Business Models

Assessment of DG Business Models from a Regulatory Perspective, and

Revenue Decoupling and Its Impact On Utility Acceptance of DG

The purpose of this series of reports is to assess the role DG has played in distribution system planning and ascertain its potential role. Despite a substantial literature on the transmission and distribution (T&D) benefits of DG there is little historical record of use of DG as a substitute for traditional utility distribution capital investment. A few utilities have experimented with DG in distribution system planning and a few state commissions have undertaken pilot projects. In general there seems to be a significant disconnect between the broad promise of DG as a distribution system asset and the empirical fact of its meager usage. Do technical or cost barriers make these investments unattractive relative to the traditional wires solution? Are cost effective DG investments overlooked because they are not embedded in utility distribution capital models nor considered in the planning process? Is the problem a lack of markets and contractual arrangements for facilitating customer-sited DG that demonstrably benefits the distribution system or adequate utility cost recovery mechanisms and incentives to encourage utility-owned DG that could substitute for system investment? In order to move forward it is essential that the regulatory authority understands the net benefits strategically sited DG can provide to ratepayers and the primary factors precluding development of cost saving utility or customer owned projects.

The regulatory authority has to balance the inter-related concerns of reliability, cost of service and adequate return. The alignment of infrastructure investment, customer rates and return on investment is perhaps the most critical parameter of a distribution utility's ability to fulfill its mission effectively, efficiently and in a manner that comports with public expectations. This has become an increasingly difficult balancing act. The advent of market forces triggered more than a decade ago by electric industry restructuring has resulted in the emergence of new energy technologies and services that can reduce end-users' reliance on utilities for power.[1] The convergence of these trends in New York's power markets with escalating concerns about climate change and the national security implications of imported energy is likely to force a paradigm shift in the conventional electric utility business model over coming decades.

Barring reversal of current trends, the electric utilities in New York State will need to develop and deploy new business models to serve their customers in an economically efficient manner. Distributed generation and the web of services and systems collectively described as the "smart grid" will provide compelling opportunities for the electric utility industry to reinvent its basic business model.[2]

[1] Demand erosion has been erroneously attributed to these new services and technologies. These phenomena are the agents of change induced by market restructuring. The latter not the former is the primary cause of demand erosion.
[2] See CERES, The Electric Utility Industry for the 21st Century.

2. KEY FINDINGS TASKS 1-5

2.1. Task 1: Benefits of DG - Actionable Findings

- Strategically sited and highly efficient DG can serve key objectives for utilities and the State, including:
    - Improve system-wide energy efficiency
    - Relieve local congestion
    - Improve distribution reliability
    - lengthen distribution equipment lifetimes
    - Lower wholesale power costs by reducing operating hours of highest priced generators
    - Avoid or defer distribution system capital investments
    - Combined heat and power (CHP) installations (sometimes called cogeneration) operating at the right times and in the correct locations can provide benefits to the electric system, but with no markets for capturing the value of these benefits, private parties will under-invest in CHP systems that may provide substantial ratepayer benefits.
- The full array of benefits (and costs) of high efficiency, low emissions CHP have not been rigorously measured and therefore the ratepayer and system value is not well understood.
- Policy frameworks that reward outcomes that support the State's goals and regulatory objectives rather than incent specified technologies are likely to be more cost effective.
- Policies that are weighted toward favoring clean DG/CHP projects with the largest non-compensated benefits yield a greater return to the ratepayers and citizens of New York.
- Utilities should recognize the option value that DG offers when it defers the need for T&D upgrades. Once made, large utility investments are irreversible. By reducing demand at congested locations in the T&D system, DG buys time for the utility to assess whether or not their growth projections materialize. This can save the utility by reducing the cost of overestimating demand.[3]
- DG's benefits are easier to manage at larger scales. Aggregating smaller DG systems may allow utilities and customers to capture the full array of DG benefits.
- New investments in T&D infrastructure and the Smart Grid should be screened to ensure that they facilitate greater integration of clean DG / CHP assets.

2.2. Task 2: DG Business Models - Actionable Findings

- HVDG model is likely to work best in NYCA Zone J, where wholesale energy and capacity costs are highest, and the rate of peak load growth is greatest in the state.
- Utilities place the highest priority on reliability; the DG/CHP investor's primary concern is economics. Any feasible business model must bridge this gap by giving the utility adequate assurance that the resource will operate when required and the end-user the assurance that it does not have to cede control or operate in a manner that makes the project economically infeasible.
- Utilities have struggled to develop business models for deploying DG that resolve concerns about loss of revenues, contractual arrangements and risk management. New ownership, operation and maintenance models may provide mechanisms that resolve these concerns with DG.
- Utility ownership of DG is not prohibited, but is challenging in New York because utilities have to demonstrate that the ownership of generation assets provides a substantial public benefit, does not harm competition and provides measures to mitigate market power.
- Utility ownership of DG raises the possibility of negative impacts on wholesale energy markets and the DG

[3] See Chris Gazze, Con Edison's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction, ACEEE Summer Study, 2010.

industry, but such negative impacts could be mitigated to a great extent when DG resources are (a) used to meet on-site or local demand or mitigate T&D constraints, (b) small in size relative to the size of the wholesale market, (c) intermittent resources such as PV and wind, and/or (d) commissioned and maintained by third party private companies.

- Under existing regulatory structures, utility-owned DG business models are more likely to achieve win-win outcomes than customer-owned DG because (i) non-market benefits are more readily internalized by the utility, (ii) the utility maintains a high degree of operational control, and (iii) the model conforms readily to traditional rate-of-return regulation (e.g. rate-basing the asset).
- Customer-owned DG will only attract interest from utilities if regulatory and business structures are changed to allow cost recovery.
- Utilities need to deploy capital in ways that provide affordable and secure electricity. Pursuing approaches that are overly capital-intensive puts upward pressure on electricity rates. Over time increasing rates become politically charged and the risk of unfavorable return on capital increases. This, in turn, could lower a utility's credit rating, perceived risk and increase its marginal cost of capital.
- Utilities should employ open and transparent planning processes that consider the risks, probabilities, benefits, impacts and applications of multiple distribution system resources, including demand reduction and customer-side DG/CHP assets, under a variety of scenarios.

2.3. Task 3: Comparative Analysis of DG Implementation Models–Actionable Findings

- The issues likely to impede the successful deployment of the models described in the Task reports are complex and interconnected. As a result, policies or programs that pursue piecemeal solutions to these barriers are far less likely to succeed than those that implement an integrated suite of solutions.
- Utility-owned business model is more or less attractive to the utility depending on its appetite for, cost of and access to raising capital, as well as the relative capital cost of meeting a given need with T&D investment or DG investment.
- Utilities that pursue least-cost DG investments are likely to reduce capital investment risk. The inherent risk management benefits of this approach are apt to be recognized by the financial institutions that rate and lend to electric utilities.
- For some utilities, other aspects of their financial situations (e.g., rating agency treatment of long-term procurement contracts as debt) may interact with the need to raise capital for utility-owned DG (or T&D) investments in ways that make either type of investment difficult. In such cases, customer-owned DG models may be more attractive.

2.4. Task 4: Revenue Decoupling Mechanisms (RDM)–Actionable Findings

- Decoupling plus - By itself, decoupling does not provide utilities with adequate financial incentive to aggressively pursue DG. Once a policy is in place to protect the utility from declining sales, utilities may need additional incentives for meeting savings targets that hold harmless decline in return on investment (ROI).
- Incentive ratemaking for utilities to provide premium returns on the “right” utility investments may complement decoupling. Additional incentives to complement revenue decoupling to recover these utility losses are described in the Recommendations section below.
- Decoupling is a necessary, but insufficient strategy for facilitating full deployment of economically viable, environmentally preferred customer owned DG. RDM does not re-capture that loss. RDM also fails to address other issues that may affect the operations and future profitability of a distribution utility.
- There is inertia in the current system that is rooted in long-lived historical investments in models, methods and procedures for distribution system planning. Retooling to meet new challenges of incorporating technically feasible and economically viable DG/CHP as a substitute for traditional distribution system capital will likely not occur without external prompting.

3. SUMMARY OF TASKS 1-5

While there are no absolute legal barriers precluding utility ownership of DG systems, the economic, institutional, technical and regulatory barriers to utility ownership of DG systems are overwhelming. Using customer-owned DG as a distribution system asset remains problematic for a variety of reasons, most importantly the disparate priorities of the utility and the DG end user. The utility places a premium on reliability whereas the prospective DG owner is interested in economic return. Contractual arrangements must balance the utility's interest in controlling the asset to meet reliability criteria and the end-users concerns about the impact of utility restrictions on the economics of their investment. Under existing regulatory structures, utility-owned DG business models could balance these issues well; however, utility ownership of DG is likely to face significant challenges in New York.

New York's T&D infrastructure is aging rapidly. In certain areas, rising demand requires the system to operate close to its maximum capacity for more hours of the year. The continued upward trend in infrastructure costs is an important factor behind rising rates. Rate increases for the businesses as usual model may become unsustainable. Customer-side DG provides an alternative source of capital. There is a growing concern for more effectively addressing cost-management in the distribution planning process. This provides an impetus for assessing the net benefits of utility or customer-owned DG as a distribution system asset and new business models, capital planning procedures and regulatory structure that will enable its realization.

3.1. Task 1: Benefits of DG

This Task Report reviewed the conceptual benefits of deploying DG/CHP with an emphasis on avoided T&D benefits, identified and synthesized existing estimates of such benefits specific to New York State or from beyond New York where New York specific examples are not available. With regard to valuing T&D avoided costs specifically for DG/CHP, we identified a number of different practices to address DG reliability including (a) demanding high reliability of DG units, (b) requiring back-up generators or physical assurance, (c) redundant monitoring and remote control, and (d) no redundancy, no physical assurance.[4] These benefits accrue to the utility, the ratepayer and society disproportionately and in different forms. The Task report also reviewed the barriers to a healthy market for DG implementation in New York, and some measures to address those barriers. Following is a summary of the benefits of DG; for greater detail on these benefits, please see the Task 1 Report.

[4] For DG, Con Edison required that the loads served by the DG system be permanently isolated from the Con Edison grid. In other words, "physical assurance" meant that the Con Edison network could not be used as a back-up in the event of DG failure. This practice refers to how Con Edison treats its small gas turbines located on W. 59th St and W. 74th St. "No redundancy, no physical assurance" refers to ConEdison's recent practices where ConEdison did not apply the same strict standard to its own small generators on W. 59th St and W. 74th St. Those facilities were treated as able to defer T&D projects and to provide adequate assurance for load relief.

Benefit	Description	Value
Avoided Transmission and Distribution Capacity Costs	DG can be installed instead of T&D system upgrades to relieve congestion, thereby avoiding or reducing T&D investment.	$34 to $66 per kW-yr ($2008) for upstate New York and $100 for downstate New York[5]
Avoided Electricity Generation Costs	DG can reduce the volume of energy that would otherwise be generated and sold in the wholesale energy market.	Levelized wholesale prices over the period 2008 – 2030 range from $59 to $63 per MWh (2008$) in Zones A-E (exhibiting the lowest prices) and in the range of $77 to $88 in Zones J and K (representing NYC and Long Island and having the highest prices.[6]
Avoided or Deferred Generation Capacity Investments	DG can help reduce peak power demand thereby delaying, decreasing, or avoiding the need to build or upgrade power plants.	Levelized capacity prices over 12 years of approximately $33/kW-yr. to $66/kW-yr (2008$) for upstate and $110 for NYC. [7],[8]
Wholesale Price Impact or Demand Reductions Induced Price Effect	DG can help reduce peak power demand thereby avoiding use of the most expensive peaking generation units and decreasing the market-clearing price for *all* energy in those hours.	Ranging from $184 per kW-yr (2008$) in New York State excluding Con Edison's jurisdiction to $613 per kW-yr for Con Edison's jurisdiction. A statewide average price effect was estimated to be $433 per kW-yr (2008$), with price effect lasting 3 years.[9]
Increased Reliability	DG can increase system reliability by diversifying generating technologies, reducing the average size of generators and the distance between generators and load.	Estimates of this benefit were beyond the scope of this report, but are discussed in FERC's report *The Potential Benefits Of Distributed Generation And Rate-Related Issues That May Impede Their Expansion*.

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[5] New York PSC. Order Approving "Fast Track" Case 08-E-100; Optimal Energy, Economic Energy Efficiency Potential New York Service Territory, 2008.

[6] Appendix 2. Table 1. Energy LBMP Price Forecast: by NYISO Zone ($/MWH in $2008). Case 08-E-1003 ORDER APPROVING "FAST TRACK" UTILITY-ADMINISTERED ELECTRIC ENERGY EFFICIENCY PROGRAMS WITH MODIFICATIONS(Issued and Effective January 16, 2009)

[7] NY DPS; *Order Approving "Fast Track" Utility-Administered Electric Energy Efficiency Programs with Modifications*, issued and effective January 16, 2009; Optimal Energy, Economic Energy Efficiency Potential New York Service Territory, 2008.

[8] In "Order Approving "Fast Track" Utility-Administered Electric Energy Efficiency Programs with Modifications, PSC staff identified that Con Edison projects revealed that avoided distribution costs for downstate ranges from $22 per kW-year to $307, $549, and even $609. $100 per kW-year estimate for Downstate is currently used by NY PSC as a placeholder until a better number is estimated in future studies.

[9] The estimated net retail price impact includes a reduction in the wholesale commodity price of electricity of 0.26 cents per kWh, netted against the estimated retail price increase of 0.1 to 0.2 cents per kWh, due to the collection of ratepayer funds to pay the price premium for the purchase of renewable energy under the RPS and "backing out" of the more expensive, less efficient fossil fuel-fired units. See http://www.nysenergyplan.com/final/Renewable_Energy_Assessment.pdf

Avoided Ancillary Service Costs	DG can provide (or reduce the need for) certain ancillary services necessary to maintain grid reliability and stability.	Ranges from near zero to 1.5 cents/kWh. [10]
Provide Back-up Reliability	DG can provide back-up power for customers who value uninterrupted power supply.	EPRI: $100/kW for one type of customer. [11] Navigant study cited LBNL and NREL reports that measure the benefit of increased outage support for PV with battery usage as backup reliability ranging from 0 - 2.7 cents/kWh. [12]
Avoided Environmental Costs	Clean DG can reduce overall power system emissions of criteria pollutants and greenhouse gases.	At a price of $15/ton for carbon reduction, this benefit is equivalent to a savings of $7/MWh. 2008 estimates of levelized cost of carbon emissions ranged from $15.1/ton to $46/ton (2008$) over a period through 2030. [13]
Avoided Costs of Fuel Displaced by Use of Waste Heat	DG or CHP facilities that recover waste heat displace the cost of purchasing fuel to provide space or process heat.	At $8/MMbtu for displaced fuel with 40% heat recovery, the value is estimated to be about $40/MWh. [14]
Hedge Against Fuel Price Increases	DG can reduce a utility's exposure to uncertain future gas prices.	No value provided
Power Quality	DG can improve power quality on an area or site-specific basis	No value provided

Though New York has removed certain barriers to DG/CHP deployment, growth in the DG/CHP markets has remained slow and barriers to the development of more robust markets for DG/CHP are numerous. [15] Connecticut, perhaps the most aggressive among the states in marshalling an array of incentives to address a broad range of the

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[10] E3/RMI, Methodology and Forecast of Long Term Avoided Costs, 2004; Contreras, et al., Photovoltaics Value Analysis, 2008, at p.13, citing E3/RMI report; Smeloff, E., Quantifying the Benefits of Solar Power for California, 2005; Hoff, T.E., et al. The Value of Distributed Photovoltaics to Austin Energy, 2006; Contreras, et al., Photovoltaics Value Analysis, 2008, at p.13, citing Hoff, et al Austin Report; Navigant Consulting Inc., Distributed Generation and Distribution Planning, 2006; and US DOE. The Potential Benefits Of Distributed Generation, 2007, p. 4-9.

[11] EPRI. Economic Costs and Benefits of Distributed Energy Resources, 2004, at p. 2-11

[12] Contreras, et al. Photovoltaics Value Analysis, 2008, at p.15, citing Hoff, T.E., et al., Maximizing the Value of Customer-Sited PV Systems Using Storage and Controls, 2005; and Hoff, T.E., et al., Increasing the Value of Customer-Owned PV Systems Using Batteries, 2004.

[13] Schlissel, et al. *CO2 Price Forecasts*, 2008.

[14] EPRI. Economic Costs and Benefits of Distributed Energy Resources, 2004, at p. 2-8.

[15] Barriers include, but are not limited to (a) Higher initial capital costs, (b) acquiring the financing and competing against other capital investments that are more central to the end-user's core business, (c) disincentives that utilities face due to lost revenues and contraction of their asset base that make them at best indifferent and at worst opposed to the development of DG/CHP projects within their service territory, (d) uncertainty about future gas costs and the spark spread, (e) reductions in savings that result from the imposition of standby charges to purchase delivery services from the utility for portions of the annual energy and capacity demand not served by the customer-sited DG facility, and (f) an inability to capture and monetize certain value streams that the DG/CHP facility creates (e.g. criteria pollution reduction, greenhouse gas reduction, and T&D congestion benefits).

existing barriers, has shown that a multi-faceted incentive plan can deliver a sizeable amount of new customer sited distributed resource within a short time frame. Connecticut adopted a combination of grants, loans, incentives, and cost waivers to spur installation of distributed resources. New York State has also created a gradually increasing portfolio requirement on distribution utilities for service from energy efficiency and CHP.

3.2. Task 2: DG Business Models

This Task developed, examined and refined the operational and programmatic elements of three business models for facilitating DG deployment in New York State: the Utility Ownership Model, Refined Request-For-Proposal Model and High-Value Development-Zone Model. The task also identified implementation issues and potential risks and benefits from each model.

3.2.1. Utility Ownership Model

The utility owned DG business model is one where a distribution (or vertically integrated) utility, in its distribution planning process and operations, actively seeks opportunities to deploy cost-effective DG solutions to alleviate grid congestion and to defer or avoid distribution system equipment upgrades or construction. Utilities would receive a regulated return on their DG investment, a critical assumption for a model to make economic sense. Under this model the utility could own and operate DG on the distribution system or other utility owned property (attached to a distribution circuit or at a substation, but on the utility's side of the retail meter), DG on a customer site (on either side of the retail meter); or DG control and monitor equipment, such as inverter and meter, at a customer site. [16]

Whether utilities in New York are actually allowed to own and operate DG is not immediately clear. Based on the PSC's Vertical Market Power Policy Statement in 1998 and a recent order on RPS on April 2010 (particularly concerning DG development in downstate), we found that utility ownership of DG is not illegal; however, it is very challenging because utilities have to demonstrate that the ownership of generation assets provides a substantial public benefit, does not harm competition and provides measures to mitigate market power. The April Order specifically states that demonstrating the benefits of utility ownership relative to customer owned projects would be a challenge because there are few customer projects in the downstate area. [17]

To analyze the impact of utility ownership of DG on the wholesale energy market, power businesses and the DG industry, we explored market power issues associated with the utility's ability to leverage its control of the distribution network to unfairly benefit its DG businesses. For example, a utility could delay non-utility interconnection requests or impose unrealistic interconnection requirements. Appropriate rules and standards established by the NYISO, FERC and the PSC could help mitigate this problem. On the other hand, by improving a utility's understanding of DG interconnection, utility ownership could lead to a more standardized and efficient interconnection process and a more precise assessment of DG benefits. A utility also has the ability to influence T&D constraints that affect the operability or profitability of generation owned by others. It is likely this problem is insignificant when DG resources are (a) used to meet on-site or local demand or mitigate T&D constraints, (b) small in size relative to the size of the wholesale market, and (c) intermittent resources such as PV and wind. Utility ownership may also appear to provide the utility with an unfair competitive advantage in the wholesale market and the DG industry over wholesale generators and DG project developers. When utility DG resources are small in size, limited to a particular purpose, and/or provide market players with ample business opportunities, this issue can be mitigated to a great extent. For DG developers, the issue could further be mitigated when utilities use their own property to site DG projects, and contract out EPC and maintenance work to private companies.

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[16] In Task 3, the Team investigates regulatory burdens and management complexity associated with utility owned DG projects for numerous issues such as cost recovery, project development, DG monitoring and operation, sales of energy and capacity from DG, and customer contracting. Project and program costs of utility owned DG are compared to a scenario where private companies install DG for T&D support.

[17] Nevertheless, we note that where utilities own DG related equipment such as meters, inverters and controls, with the customer owning the DG resource itself, the benefits of DG can be recognized without requiring the demonstration of utility ownership of the resource.

3.2.2. Refined Request for Proposal (RRFP) Model

In October 2001, NYSPSC ordered New York's investor-owned electric distribution companies (EDCs) to implement a three-year DG pilot program designed to test whether DG could cost-effectively defer the need for distribution system infrastructure investment (PSC Opinion No. 01-5, 2001). Each EDC was ordered to issue Requests for Proposals (RFPs) in the areas of greatest need. Between 2002 and 2004, there were a total of 22 RFPs issued; however, none resulted in proposals that were selected by the respective utilities as the least cost option. Over 75% of the RFPs that were issued did not receive a bid.

The RRFP model facilitates procurement of customer-owned DG resources in high deferral value locations through utilities. The model is refined to address recommendations made to the PSC on ways to improve the existing program or a future program. An additional advantage is that the RRFP will be familiar to stakeholders because the fundamental structure of the RFP model remains unchanged. Developers, regulators, and utilities are experienced with the essentials of this model. The RRFP model offers two major benefits over the previous model.

First, a better integration of the key stakeholders will allow for a more successful program. This integration could include the forming of a collaborative to provide greater transparency to all stakeholders, more extensive and effective program marketing efforts, retaining a third-party to manage the review, ranking and selection of bids according to an objective analysis based on predefined value standards.

Second, an integration of other demand side resources into the bid process would provide greater opportunities for the development of responsive bids by project developers that can defer or avoid T&D investment. This was not the case under the prior RFP process. Evidence from numerous other studies points to the benefit of a multi-resource approach, aggregating a variety of resources including permanent measures like energy efficiency retrofits and temporary ones such as demand response.

Financing costs, including transaction costs, the impact of purchased power costs on the utility's balance sheets and the potential for resulting higher borrowing costs should be accounted for in the RFP and bidding process. Bidders could be required to provide information necessary to complete these evaluations. The RFP shall describe the methodology for considering financial effects.

3.2.3. High Value Development Zone (HVDG) Model

The HVDG model is a "pay for performance" mechanism, offering an incentive for the procurement of DG resources in specific geographic locations or "zones" identified as the most valuable deferral opportunities in order to direct DG development to the areas on the distribution system where it is likely to create the greatest system benefits. [18] The HVDG model has the distribution utility offer a payment commitment to a DG resource owner for an agreed upon term, conditional on certain operational requirements, as well as penalty measures for under-performance. The first-come, first-served nature of the model allows the distribution utility to exercise control over the economic value of the transaction, not obligating the utility to overpay for DG capacity, or to commit to payments where the DG resources are not sufficient to defer a wires investment. [19]

The HVDG model creates a market for capturing the benefits of strategically located DG. In theory this approach should lead to more economically efficient siting decisions by potential end-use customers. Suppose a multi-facility hospital was considering one of two CHP locations. All other factors were equal at the sites, in terms of operational efficiencies, return on investment, and net present value of savings, but site #1 offered a significant local distribution system saving that was not realized by site #2. There is no mechanism today that would direct investment to site #1 in preference to site #2. As a result there is an under-investment in CHP that can provide distribution system value. The outcome is not rewarded therefore it is not taken account of by private decision makers. The HVDG model addresses this situation by creating a market where one does not exist.

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[18] The RRFP model may also include aspects of performance-based payments (or penalties for lack of performance), but such payments are central to the HVDG model.

[19] This is in contrast to the standard offer procurements under earlier versions of PURPA.

3.3. Task 3: Comparative Analysis of DG Implementation Models

Task 3 considered the risks and benefits associated with each of these DG deployment models, especially those manifested in New York State. The report identified the following clusters of overarching issues likely to impede any and all of implementation models:

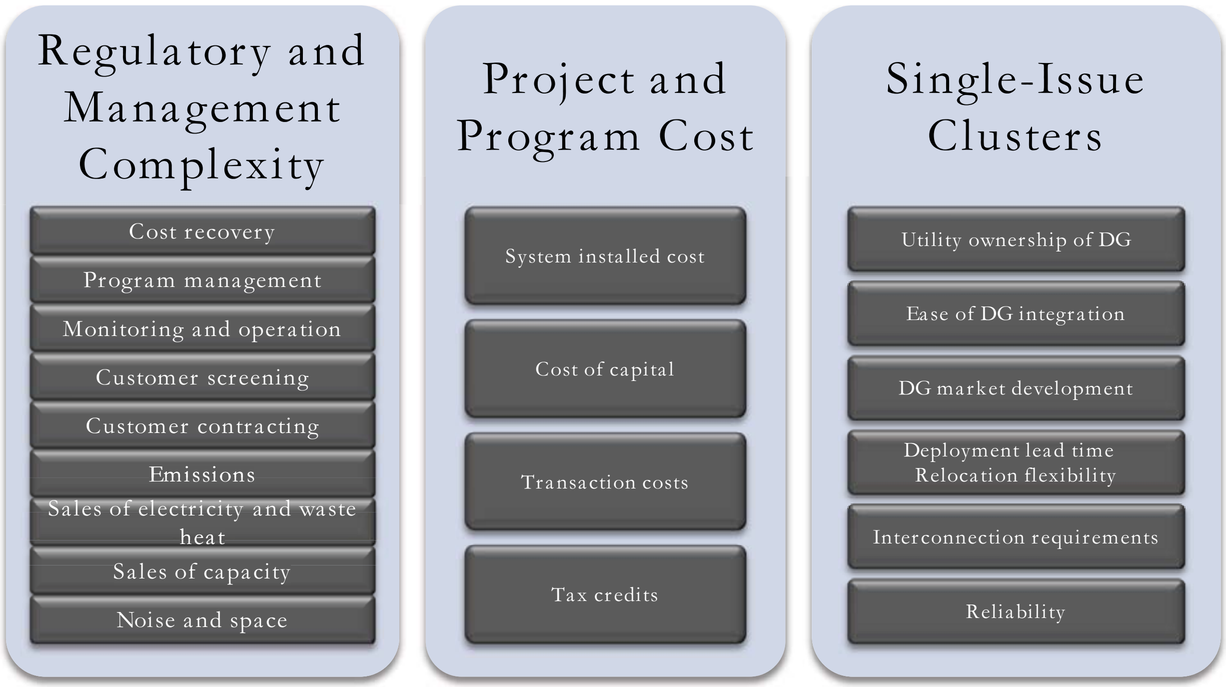

Figure 1 – Summary of Overarching Issue Clusters Identified in Task 3

3.4. Task 4: Revenue Decoupling Mechanisms

The Task 4 report explored the role of revenue decoupling mechanisms (RDM) for addressing utility disincentives to the use of DG in distribution system planning.

Under traditional ratemaking, reductions in energy consumption reduce utility revenues. This will translate into lower earnings for any utility that is recovering fixed costs through its rate per kWh. This creates a disincentive for utilities to support DG development, despite the many advantages DG can provide. In its broadest form, revenue decoupling adjusts rates so the utility receives annual revenues sufficient to cover the fixed cost portion (including ROE) of the utility's revenue requirement.

In 2007, the NY PSC approved implementation of a broad based decoupling approach, and directed the utilities to file revenue decoupling proposals in any ongoing and all newly initiated rate cases. The approach required the utilities to submit mechanisms that would true-up forecast and actual delivery service revenues, an approach significantly more far-reaching than a net lost revenue adjustment that focuses on identifiable losses from specific energy saving programs. The approach taken by the New York Public Service Commission avoids debates over what lost revenues are attributable to energy efficiency programs, and may reduce a utility's incentive to oppose energy appliance standards and other state and federal measures that might reduce its sales.

Nevertheless, when a utility uses customer sited DG as an alternative to investing its own capital, this results in a rate base smaller than it might otherwise have been, and RDM does not re-capture that loss. RDM also fails to address other issues that may affect the operations and future profitability of a distribution utility. Thus, the decoupling prescribed by the Commission may be seen as a necessary, but insufficient policy approach for facilitating the more rapid deployment of economically viable, environmentally preferred customer owned DG. Additional incentives to complement RDM in order to recover these utility losses are described in the Recommendations section below.

3.5. Task 5: Stakeholder Input

The Fifth Task of this study consisted of activities designed to collect input from various New York DG stakeholders. These activities included the convening of a series of meetings and interviews with interested parties, and the dissemination of a survey. The results of these efforts revealed a range of concerns related to the use of DG as a distribution system resource. A total of four stakeholder meetings were held, three in person and one via teleconference. Additionally, numerous individual interviews were conducted by telephone.

3.5.1. Stakeholder Meetings

The first meeting with National Grid included Tom Bourgeois, Dana Hall, Kenji Takahashi and National Grid staff. The second meeting with Con Edison included Tom Bourgeois, Dana Hall, Margarett Jolly, Chris Gazze and another Con Ed staff person. Both meetings concentrated on the three deployment models as well as utility ownership of DG resources in Massachusetts and New York respectively. The third and fourth meetings were held at Pace University NYC as part of two larger conferences with audiences that included DG developers as well as utilities. Among the topics discussed were T&D deferral values, impact on grid reliability, operation of the DG resource, pricing incentives, associated regulatory requirements, management complexity, and program and project costs.

3.5.2. Survey and Interviews

The project team created a survey from the identified key issues and concerns surrounding DG implementation. This survey was disseminated at the stakeholder meetings, and also through email transmittal to DG stakeholders. There was a total of twelve surveys completed and returned to the project team. In addition, numerous individual interviews were conducted by the project team members throughout the course of the study. The interviewees, who represented utilities, private DG developers, regulators and other interested parties, are listed in a matrix in the Task 5 report.

4. SYNTHESIS OF SUMMARY

This section evaluates lessons learned from the preceding set of summaries.

5. FLEXIBILITY IS FUNDAMENTAL.

While the deployment models described in the preceding sections are discussed as distinct concepts, the programmatic elements they contemplate are sufficiently flexible to allow development of various hybrid and alternative models. This flexible framework aims to ensure this report remains relevant as market and regulatory circumstances change in anticipated and inevitably unanticipated ways. In this sense, these models are more like points of departure than discrete destinations. For example, as has been experimented with in California, the state could also explore a hybrid model that includes both the utility ownership model and one of the customer owned DG models we suggested by limiting the capacity of DG under each model. This would create a competition between the two models and could keep the cost of DG projects low.

6. UTILITY OWNED DG MODELS ARE USEFUL IN SOME CONTEXTS.

Under current regulatory structures, utility ownership of DG is not prohibited, but faces significant hurdles to succeed in New York. Still, as discussed in the report, utility ownership of DG potentially brings about additional benefits to the state if (1) it is restricted to certain uses (e.g., T&D support) and certain capacity limits, and (2) it maximizes the use of third party private contractors for DG commissioning and maintenance work. For example, utility ownership could lead to a more standardized and efficient interconnection process and a more precise assessment of DG benefits. It would also make utilities more comfortable relying on DG for T&D support. Further, it could work to spur competition in the private sector without disrupting private sector's business opportunities. Given these benefits, we suggest policy makers investigate the usefulness of the utility ownership of DG for the purpose of T&D support.

7. DECOUPLING IS NOT A SILVER BULLET.

Addressing the throughput incentive is necessary, but not sufficient to motivate utilities to accelerate the deployment of DG. Decoupling makes the utility indifferent to lost revenues from DG, but does not alone motivate them to invest in DG. Shareholder incentives (e.g., shared savings, rate of return adders) may be needed that align the financial interests of distribution utilities and the preferences of regulators for greater levels of economically viable investments in energy efficiency and clean DG.

8. REVENUE EROSION WILL LIKELY ACCELERATE WITH OR WITHOUT DG.

While concerns about revenue erosion are justifiably grave, it would be a mistake to consider DG the cause of revenue erosion. Revenue erosion associated with DG deployment is the result of market forces set in motion more than a decade ago by the decision to deregulate power markets in New York State. If DG does not drive revenue erosion, energy efficiency or innovative ESCO products will do so in its place.

9. GEOGRAPHIC CONTEXT IS CRITICAL.

The recipient and magnitude of DG benefits depend on the context and depend on a host of factors. Private benefits, such as savings on energy bills, accrue to the end-users, as is any saving from use of waste heat in CHP. Other benefits accrue beyond the site, but mainly remain "localized." These benefits include local distribution system benefits such as reductions in area distribution capital costs, enhanced local reliability and power quality. Projects operating at the right times and at the right locations on stressed portions of the distribution system may provide significant savings in utility capital investment and maintenance and operating cost, reducing distribution bills for consumers in the long run and enhancing utility's ability to access capital. This is an attractive feature in certain areas of New York, as distribution capital costs can be a key factor driving utility revenue requirements. This type of benefit though potentially demonstrable is presently an uncompensated gain for the local utility that occurs as a positive side effect of DG. A third set of benefits accrues regionally and includes air quality improvements and reduced wholesale energy prices. Reductions in energy demand of sufficient scale occurring at super peak hours can curtail the hours of operation of the most expensive generation assets on the existing electric power system. This occurrence has been titled "Demand Reduction Induced Price Effects" (DRIPE) and has been recognized as a benefit of energy efficiency and DG. The magnitude of the benefit of air quality improvements depends on the type of DG technologies and fuels. CHP and renewable energy based DG such as solar and wind are likely to improve air quality significantly. Finally, there are state-wide, national and international benefits that can be separately identified and in some cases quantified.

The utility representatives interviewed for this report noted that there are significant resource costs for identifying strategically targeted DG sites and for bringing these projects to conclusion. In the absence of programs that compensate the utility for incurring these execution costs there is no reason for a profit maximizing utility to undertake them and not budget in which to allocate the efforts and expenditures. On the other hand, for traditional investment in utility distribution capital, there are well developed protocols including models, capital budgeting procedures, site selection/project design criteria and clear rules for regulatory recovery of costs and return on investments made.

10. NO "ONE-SIZE FITS ALL" SOLUTIONS.

The specific circumstances of a specific utility will have major implications for the application of these models. For example, utilities concerned about securing access to capital on favorable terms are likely to pursue whatever DG ownership model is most likely to facilitate this access. If a utility has difficulty obtaining additional capital or is otherwise reluctant to invest rate base, it could see the customer-owned DG models as advantageous because they do not require utility financing. Capital constrained utilities tend to minimize capital expenditures to protect their bond ratings and cost of capital by avoiding over-leveraging. On the other hand, utilities with ready access to capital and confidence in their ability to obtain recovery for rate base additions through their Commission will tend to prefer expanding their asset base by increasing capital expenditures. Such utilities may or may not prefer DG investment depending on (1) its need to minimize capital expenditure to support growing distribution service demand, (2) DG economics over traditional wires solutions, and (3) reliability of DG systems.

11. WHAT BROUGHT US HERE WON'T TAKE US THERE.

Utility planners have developed a variety of independent planning models for expanding the reach of T&D infrastructure while maintaining the system's reliability and safety. The extent to which DG has been integrated into these models appears to vary widely from one utility to the next. As a general matter, the utility industry has only recently begun to grapple with incorporating DG into conventional planning protocols. There is a paucity of specific guidance for integrating DG in conventional planning protocols for managing the electric system.

As a result, DG has typically been deployed in an ad hoc manner. Achieving DG's potential will require making it a routine part of the planning process. The development of planning protocols and forecasting products that contemplate DG will allow utilities to deploy cost-effective DG in response to system problems.

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