New York State Energy Research and Development Authority

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

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

Conceptual Benefits to Deployment of DG for Grid Support
Task #1

Prepared for the

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# 1 OVERVIEW

Distributed generation (DG) and combined heat and power (CHP), and more broadly Distributed Energy Resources (DER) that encompasses DG, CHP and energy efficiency resources (EE) can provide numerous benefits both to the electric transmission and distribution (T&D) and to society overall.[1] For some time the potential benefits of DG CHP have been identified, speculated upon and in some instances, analyzed and quantified. Studies have been conducted by industry participants, utilities, regulators and their national and regional organizations, the Department of Energy and the National Energy labs, and numerous energy experts and consultants. These numerous studies have identified numerous benefits including avoided costs of energy, generation capacity and transmission and distribution (T&D) capacity; avoided line losses; wholesale price impacts, improved utility system reliability; distribution power quality; hedge value against volatile fuel prices [2] and other positive electricity market impacts; as well as un-priced societal benefits such as reduced green house gas emissions and air quality benefits from the reduction of criteria pollutants. The analysis in this paper focuses on the benefits of DG and in particular DG in the form of CHP. Our primary interest is in the benefits that DG/CHP can provide for the electric distribution company in supporting operations and capital planning for the T&D system.

In recent years, policy makers and stakeholders have identified T&D avoided capacity cost as an important benefit of DG and CHP, and perhaps one in which there was a strong linkage with the electric distribution utilities. The Electric Power Research Institute (EPRI) and other organizations initiated work on identifying "win-win" opportunities in this area. In New York, Massachusetts, California and other states, there have been experiments with programs designed to avoid or defer utility distribution system capital investments using DER.

The emphasis on investigation into T&D avoided capacity cost may reflect, in part, the *relative* ease of quantifying and monetizing the magnitude and nature of that particular benefit, and also because the distribution company is in the best position to create an environment where DG/CHP installations can avoid T&D costs. Recent initiatives in the study of DG/CHP avoided T&D costs can be found in the following examples.

- **Massachusetts DG Collaborative**: The Massachusetts Distributed Generation Collaborative was established by an Order on October 3, 2002 by the Massachusetts Department of Telecommunications and Energy (DTE) in order to recommend uniform standards for interconnecting DG to the electric grid. MTC's Renewable Energy Trust coordinates and funds the Massachusetts DG Collaborative, subject to the direction of the Massachusetts DTE and on behalf of the stakeholder participants, including distribution companies, customers, DG providers and environmental and public interests.[3]

- **Electric Power Research Institute (EPRI) and the National Association of State Energy Officials as a State Technology Advancement Collaborative (STAC)**:[4] The resources developed in this project are intended to encourage DER integration at the utility owned level. The project provides an economic calculator as a tool to compare the impact of different approaches and options, and to demonstrate costs and benefits to three key groups: customers, utilities/ratepayers, and society.

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[1] Lovins, et al. *Small is Profitable*. 2002.; US DOE. *Potential Benefits Of Distributed Generation.* 2007; An expanded list of references for DG benefit studies can be found in the end notes of this summary.
[2] Small changes in demand can have large effects on the price of natural gas. Displacing inefficient oil and gas boilers with CHP (even if all CHP runs on gas) can reduce demand and affect the price of natural gas. Wiser, R., et al. *Easing the Natural Gas Crisis*. 2005.
[3] The Massachusetts DG Collaborative website is: http://www.masstech.org/renewableenergy/public_policy/DG/collab_overview.htm. Last visited 1/26/09.
[4] Petrill, E., et al. *Creating Incentives for Electricity Providers*. 2007.

- **Bonneville Power Administration (BPA) Non-Wires Solutions (NWS)**: [5] BPA collaborated with stakeholders to examine transmission alternatives to delay transmission upgrades or construction, including DG, demand response, energy efficiency, and direct load control. BPA also conducted a number of pilot projects to gain real experience with certain NWS technologies and measures.

- **Southern California Edison DG study:** [6] This study investigated the feasibility of DG/CHP deferring capital investments on two "prototypical" circuits in the Southern California Edison service territory (2005). The analysis focused on a 13 MW suburban circuit upgrade and an 8 MW rural circuit upgrade. Data from a recently completed project similar to the suburban upgrade indicated a cost of about $746,000. A DG/CHP project of 200 kW in size could defer the upgrade for one year. The deferral value was estimated to be $450/kW.

While there have been studies that analyze potential avoided generation and capacity benefits attributable to DG/CHP for New York, the authors have not been able to identify an individual comprehensive study that fully evaluates the numerous benefits of DG/CHP specific to New York State. Therefore, this summary seeks to identify and synthesize existing estimates of DG/CHP benefits specific to New York State, while also including estimates from beyond New York where New York specific examples are not available. We include in this report a policy gap analysis, which briefly examines and identifies policy mechanisms that may be required to realize DG/CHP benefits for New York. Finally, this summary discusses strategies that could prove useful in overcoming DG barriers and provides examples of DG benefit quantification cases from other states.

[5] Pace/Synapse. *A Comprehensive Process Evaluation* NYSERDA, 2006, at p. 51.
[6] Kingston, T., et al.. *Exploring Distributed Energy Alternatives*. 2005.

# 2 QUANTIFYING THE VALUE OF DG/CHP

As noted above, there is a substantial and growing literature on certain uncompensated benefits associate with the operation of DG CHP systems. We emphasize for completeness and clarity that these benefits are not universal to every DG CHP system, but are a function of location, operating schedules, DG CHP system designs, reliability, and other factors. With that caveat we present an inventory of DG value estimates that has been extracted from numerous recent studies on the magnitude and scope of potential benefits that may be attributable to the operation of DG CHP systems. We attempted to gather such estimates specific to New York. Nevertheless, where such estimates are not available, we present generic values or values estimated for other regions.

**Summary of DG Value Estimates (in $2008)**

| | Upstate | Downstate (NYC) |
|---|---|---|
| Avoided Distribution Capacity | $33/kW-yr. to $66/kW-yr. | $110/kW-yr |
| Avoided Transmission Capacity | Assumed by DPS Staff to be included in LBMP avoided cost | Assumed by DPS Staff to be included in LBMP avoided cost |
| Avoided Energy | $65.97/MWh | $79.24/MWh |
| Avoided Generation Capacity | $67.64/kW-yr. | $117.92/kW-yr |
| Demand Reduction Induced Price Effect (DRIPE)-Energy | 12.87/MWh | |
| DRIPE-Capacity | $184/kW-yr. (3 years) | $613/kW-yr.(3 years) |
| Ancillary Services | 0 to $15 /MWh | |
| Back up reliability | 0 - $27/MWh or even higher | |
| Carbon Price | 0 - $7/MWh or higher (lower end for fossil based DG and higher end for renewable based DG) ($15/ton of $CO_2$ or higher) | |
| $NO_x$ Emission Benefit | negligible in $/MWh ($500 - $2,500 /ton of $NO_x$) | |
| Value of Waste Heat for CHP | $50/MWh? (40% heat recovery for 10,000 Btu reciprocating engine and $10/mmBtu of replaced fuel) | |
| Hedge Value | 0 to $9/MWh | |
| Total Avoided Cost | About $78 to $160/MWh plus $284/kW-yr. to $318/kW-yr. in the first 3 years and $100 to $130/kW-yr. thereafter | About $92 to $170/MWh plus $840/kW-yr. in the first 3 years and $227/kW-yr. thereafter |

| Benefit | Value Estimate |
|---|---|
| Avoided Distribution Cost | \$54/kW to \$157/kW<br>\$33/kW-yr[7] to \$110 kW-yr[8]<br>\$66/kW-yr |
| Avoided Electricity Generation | \$63.32/MWh[9]<br>\$87.79/MWh[10]<br>\$38.65/kW[11]<br>\$55.51/kW[12]<br>\$67.64[13]<br>\$117.92[14] |
| DRIPE | \$11.51/MWh<br>\$600/kW-yr[15]<br>\$180/kW-yr[16] |
| Ancillary | .5-1.5 cents/kWh[17]<br>.2 cents/kWh<br>0 cents/kWh<br>.3 cents/kWh |
| Backup Reliability Value | \$100/kW<br>0 – 2.7 cents/kWh[18]<br>\$20/MWh[19]<br>\$50/MWh[20] |
| $NO_x$ Emission Benefit | \$500 - \$2,500 per ton in $NO_x$ Trading Markets ($NO_x$ State Budget Program) |
| Power Quality | 33-40% reduction in power loss<br>28-45% reduction in reactive power consumption<br>\$450/kW reduction (see ____Study) |
| Avoided T&D Costs (estimated from PJM, See ORNL, Hadley 2003) | \$150/kW<br>35% coal energy displaced w/ DER<br>52% coal energy displaced w/ DG<br>Average marginal cost of power displaced by DER supply 2.99 ¢/kWh<br><br>Average marginal cost of the power displaced by the DG strategy was 2.62 ¢/kWh for baseload<br><br>Avg Displaced Efficiency 31% for the DER peaking strategy |

[7] Downstate
[8] Upstate
[9] Zones A-E
[10] Zone K
[11] Upstate
[12] Downstate
[13] Upstate, 10 year levelized value at 5% discount rate
[14] Downstate, 10 year levelized value at 5% discount rate
[15] Downstate
[16] Upstate
[17] CAISO market price
[18] PV with storage backup
[19] Commercial
[20] Industrial

| | |
|---|---|
| | Avg Displaced Efficiency 32% for the DG baseload strategy<br><br>For the PSE&G example, if it does not own the DER, would have net annual losses of $140/kW for peaking DG and $370/kW for base-load DG |
| Value of Waste Heat | Heat recovery rate of 40% |
| Hedge Value | $.4 - .9 kWh<br>Discount factor .96<br>$0-.9 kWh |

**Table 2: Summary of DG Value Estimates (in $2008)**

## 2.1 WHO BENEFITS?

To best understand the full range of benefits, it is helpful to consider them from the stakeholder perspectives of participant, ratepayer/utility and society. It is also important to recognize that a benefit to one stakeholder can be perceived as a cost to another stakeholder. For example, a customer bill reduction that benefits an individual ratepayer is typically regarded by the utility as lost revenue. If paid for by a utility efficiency program it might be seen as a transfer payment from the utility's profits or a subsidization of that lost revenue by other ratepayers.

Certain benefits clearly accrue directly to the end-user such as reductions in purchased power and fuel costs or operational improvements at the site. Other benefits, such as increased T&D system reliability, lower T&D capital costs and potential reductions in the wholesale market clearing price can be regarded as benefits to all ratepayers. Finally, there are certain broad ranging societal benefits such as some emissions reductions not monetized in the market, public health improvement and job creation that are attributable to DG CHP operation under a certain set of circumstances. [21] This summary is not intended to address those broad ranging societal goods. Instead this summary focuses on the near- and long-term potential net benefits that would accrue to participants and ratepayer/utility. [22]

This discussion of DG/CHP benefits begins with an emphasis on T&D avoided costs as the main driver of the New York DG pilot project conducted between 2002 and 2004. [23] Estimates of T&D avoided cost benefits can be complex and controversial. A thorough review must include an analysis of caveats and limitations. Actual T&D avoided costs vary by many factors such as location, time of the day, month, and year, and load growth assumptions. The actual level of T&D capacity DG/CHP could defer depends upon all of these factors as well as how quickly the DG CHP resources could be available to meet an investment need and the degree of risk associated with reliance on these DER assets.

We include in this report avoided T&D Costs and the following additional set of benefits:

- Avoided electricity generation
- Avoided and deferred generation capacity
- Wholesale Price Impact or Demand Reduction Induced Price Effect (DRIPE)
- Ancillary Services (system reliability)
- Backup reliability value
- CO 2 and Criteria Pollutant Emissions
- Power Quality

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[21] These societal benefits are broader in impact than the benefits specific to the electricity grid, as they include reductions in air pollution and carbon dioxide, health benefits from reduced pollution, macro economic benefits such as job creation and increases in disposable income.

[22] The authors use a net benefit so as to not count benefits accruing to some participants that are simultaneously costs to the ratepayers or utility.

[23] Pace/Synapse. *A Comprehensive Process Evaluation*, 2006.

- Value of waste heat
- Hedge value

## 2.2 AVOIDED AND DEFERRED TRANSMISSION AND DISTRIBUTION COSTS

### *2.2.1 When does DG/CHP reduce T&D costs?*

T&D projects are "lumpy" investments. When new T&D capacity is installed, the size of the upgrade is often designed to be large enough to meet projected future demand for the next decade or more, as demonstrated in Figure 2.1. This creates an environment where the majority of T&D capacity is under-utilized in virtually all years. In the right circumstance, DG/CHP has the potential to more precisely match growing energy demand locally and incrementally, thus avoiding or deferring the need for and the costs of upgrading the T&D system. This effect is depicted in Figure 2.2., where the capacity of the system is increased by $C_{DG}$ on the y axis and defers the original plan to the right on x axis. The resulting deferral of T&D investment can release significant investment value to be utilized in other ways. This potential investment value has been estimated in several studies. [24]

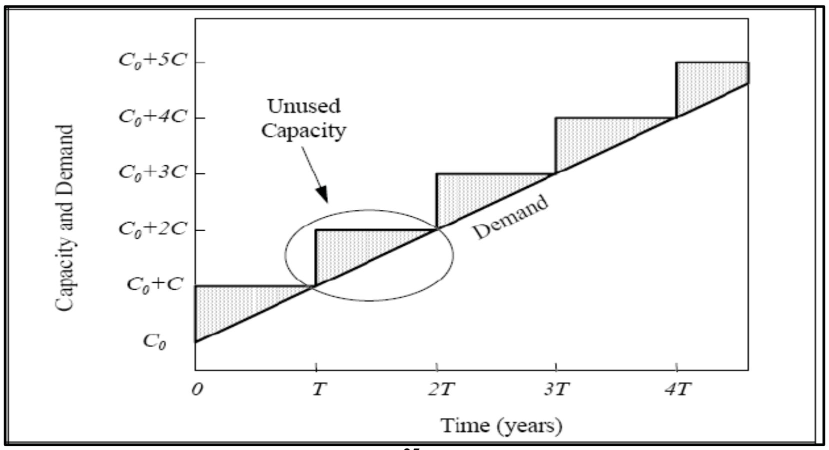


**Figure 2.1: Capacity and Demand [25]**

[24] Hoff, Thomas E., et al. *Distributed Generation,* 1996.; Carl J. Weinberg et al. *The Distributed Utility*, 1991.; Energy and Environmental Economics (E3) *Renewable Distributed Generation Assessment*, 2005.

[25] Hoff et al., *Distributed Generation,* 1996.

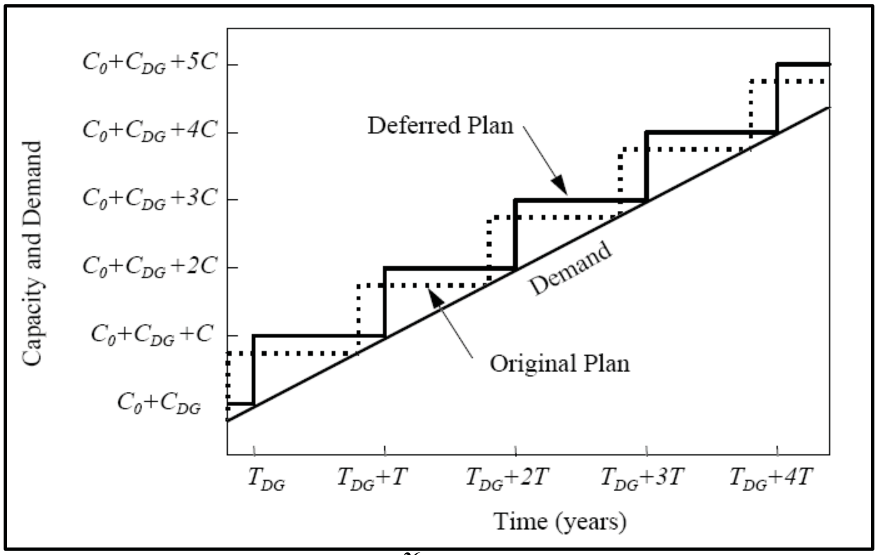


**Figure 2.2: Capacity and Demand** [26]

To avoid T&D investment, circumstances must exist that make DG/CHP projects feasible and cost-effective. Some of the circumstances we consider to favor feasibility include: [27]

(1) The DG/CHP project will be located near areas of grid congestion
(2) The DG/CHP project will operate at the right time of day (i.e., the local peak times for distribution deferral and system peak times for transmission project deferral)
(3) The peak demand will last for a short period of time (i.e., a sharp load duration curve) or DG/CHP project will have long run times
(4) The project economics will include a need for a T&D project with a large capital outlay relative to the capacity installed or upgraded. (DG/CHP is more feasible as an alternative in cases of an expensive T&D project meeting only a small capacity requirement.)
(5) There will be slow load growth in the area of the deferral
(6) The DG/CHP project will operate reliably
(7) The DG/CHP resource(s) will be of sufficient scale to serve as a close substitute for the T&D investment that is being offset.

Congestion: DG/CHP projects have to be located near the congested areas so that they can alleviate the T&D constraints. This is especially true for distribution equipment related congestion because such congestion may occur in very limited areas. Still, many DG/CHP projects located on the distribution system could beneficially impact the transmission system because each segment of the transmission system covers a wider area.

Time of operation: DG/CHP systems have to operate during local peak hours in order to alleviate congestion on the distribution and transmission systems. For most locations in the U.S., peak hours typically occur during the day time on the hottest days in the summer. The peak hours in the transmission system could be different from the peak hours in the distribution systems, and could be closer to the system peak hours because the transmission system covers a much wider area. In many instances, it may be that the number of hours DG/CHP systems would have to operate to provide needed T&D support is small, perhaps ranging from a few hours to 300 hours in the peak season. [28]

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[26] Ibid.

[27] EPRI. *Case Studies and Methodologies for Using Distributed Energy Resources*, 2005; Personal communication with Fran Cummings at MTC Collaborative and Gerry Bingham at Massachusetts DOER.

[28] For example see "Utility DG Planning Model" prepared by Navigant Consulting on January 20, 2006.

Duration of peak demand: Short duration for peak hours is an advantageous condition for DG assets serving as a T&D resource. For DG-only units that operate as peakers to cope with high load hours, O&M and fuel costs may make them less economically viable than traditional T&D upgrades if peak times are of broad duration. DG/CHP units, however, are more likely to operate as base load or intermediate load units *while simultaneously* contributing to T&D deferral, so duration of peak demand does not matter as much as it does for non-CHP peaking DG units.

Project economics: If a T&D project is relatively expensive and relieves a relatively small T&D capacity need, the unit cost ($/ kW) of the T&D capital investment is high. Consequently, the *value*, or the avoided cost (e.g., the shadow price in $/kW) of the DG/CHP alternative for the project is enhanced. Figure 2.2 below prepared by EPRI details how much avoided T&D values per kW-yr would be given a certain T&D investment and the amount of Distributed Energy Resource (DER) (including DG, demand response and energy efficiency) capacity required to solve T&D problems.[29] As can be seen in the Figure, the lower the capacity required to defer T&D projects and the higher the total cost of T&D projects, the higher the value per kW for DG projects is (e.g., the $30 million project that requires only 1 MW of load relief provides the highest value for DG in this sample table).

| | | DER Capacity Required to Defer T&D Project (MW) | | | | | |
|---|---|---|---|---|---|---|---|
| | | 1 MW | 2 MW | 5 MW | 10 MW | 20 MW | 30 MW |
| | | Values below shown in $/kW-yr | | | | | |
| Full Cost of T&D Project* ($ Millions) | 1.0 | 38 | 19 | 8 | 4 | 2 | 1 |
| | 2.0 | 75 | 38 | 15 | 8 | 4 | 3 |
| | 5.0 | 189 | 94 | 38 | 19 | 9 | 6 |
| | 10 | 377 | 189 | 75 | 38 | 19 | 13 |
| | 20 | 755 | 377 | 151 | 75 | 38 | 25 |
| | 30 | 1,132 | 566 | 226 | 113 | 57 | 38 |

*T&D investment dollars

**Figure 2.3 Deferral benefit in $/kW-year**[30]

Slow load growth: Slow load growth is advantageous for DG/CHP in a number of ways. One reason is that slow load growth allows more time for DG project development, which is especially advantageous for the types of DG and CHP projects that need a long lead time to be developed (relative to the time required to employ mobile DG units). In addition, slow load growth could allow DG to defer a T&D project longer. For example, if a 300 kW DG CHP project is put in an area with 100 kW/year growth, it may provide a three year deferral value, whereas if the growth were 300 kW/year the value is just one year and incremental DG investment may be needed to continue deferring a T&D project. Further, the avoided T&D cost (that could be a payment to DG project) would be higher per kW shortfall with slow load growth. For example, suppose the avoided cost of a distribution project is $75/kW-year and the capacity shortfall is 1 MW in the first year (see Figure 2.3 for the row for the $2 million T&D project), if the additional load growth is 1 MW (thus total 2 MW) in the next few years, the value for DG projects will be $38/kW-yr (according to the Figure), but if the load growth is 4 MW (thus total 5 MW), the value of DG projects will be $15/kW-yr.

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Examples of number of hours required to alleviate T&D congestion available at: http://www.masstech.org/renewableenergy/public_policy/DG/resources/DistributionPlanningReportsbyNavigant.htm

[29] EPRI. *Economic Costs and Benefits of Distributed Energy Resources*, 2004.

[30] Ibid.

Operational reliability: DG/CHP projects have to operate reliably to support the grid. Reliability is increased if multiple resources are operating concurrently in support of the grid problem. If one DG/CHP unit is relied on to support the grid, then its probability of failure when called upon may be 5% for example. If multiple DG/CHP units are running in an area and available to support the grid, then the probability of failure for the fleet of units failing is much smaller than the 5% figure attributable to any one unit. Customer owned DG/CHP units, not controlled and monitored by a utility, may be viewed as less reliable to the utility than are units that the utility owns and controls. Utility owned DG units that are often installed at or near substations could have more reliable operation than customer operated units. Conceivably, there could be many gradations along this continuum as well as alternative approaches to increasing the effective reliability of units. Utilities are apt to have more confidence in the reliability of units they own and control because they could routinely test the operation of such units. A Pace/Synapse 2005 report found that Detroit Edison has been operating its multiple DG projects for many years. [31] While some analyses attempt to estimate reliability of DG units, Detroit Edison did not rely on such metrics, but rather conducted careful DG operating tests before the likely events of distribution congestion.

### *2.2.2 Quantifying T&D Avoided Cost Values of DER Assets*

T&D avoided cost values can be constructed by estimating historical annual marginal T&D investment, or by evaluating planned, future T&D investment at specific sites. A site specific approach, labeled a system planning approach according to NARUC's *Electric Utility Cost Allocation Manual* examines relevant components of specific planned T&D projects. This type of analysis incorporates projected investment costs, system performance data, forecast area load growth and on this basis estimates avoided T&D costs for specific locations. [32] This approach could provide price or value signals that might induce locating cost-effective DG/CHP projects in the area of need. The current ConEdison's targeted DSM project is an attempt at utilizing this approach. [33] Other utilities and studies also took this approach including Detroit Edison, Southern California Edison, Bonneville Power Authority and the DG Collaborative in Massachusetts that included pilot projects by National Grid and NSTAR. [34] While this approach provides a detailed local area view of T&D avoided costs, it is more costly and time consuming to conduct than the alternative that uses historical annual marginal T&D investment. The site specific method requires a rigorous engineering study of the electric system to identify local system upgrade needs and incorporates small area investment and load data.

Another common method for estimating avoided T&D costs is projected embedded analysis, in which utilities use long-term historical trends (more than 10 years) and sometimes planned T&D costs to estimate future avoided T&D costs. This approach often looks at load-related investment (as opposed to customer-related) and estimates system-wide (e.g., utility service territory) average avoided T&D costs. It has been mainly applied to the evaluation of the benefits of energy efficiency programs. This approach is relatively inexpensive and less time consuming than the system planning approach as it does not require an engineering study of the electric system, nor does it require obtaining site specific load and investment data. As a weak point, it does not provide an accurate picture of avoided costs for specific T&D projects. It fails to capture the highest value projects that DG/CHP might defer. Still, an average value estimated using the projected embedded analysis does provide an indicator of T&D avoided costs sufficient for evaluating DG/CHP for an energy future scenario that assumes significant amount of DG/CHP deployment statewide. The value would provide a rough estimate of long-term T&D avoided cost values for DG/CHP projects that could reliably operate to support the grid system. Examples of the studies using the projected embedded analysis are:

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[31] Pace/Synapse. *A Comprehensive Process Evaluation*, 2006.
[32] NARUC. *Electric Utility Cost Allocation Manual,* 1992.
[33] Request for Proposals to Provide Demand Side Management to Provide Transmission and Distribution System Load Relief and to Reduce Generation Capacity Requirements, Con Edison, August 28, 2007.
[34] Pace/Synapse. *A Comprehensive Process Evaluation*, 2006; Jakubiak. *DG Comes to Detroit Edison*, 2003; Kingston, *Exploring Distributed Energy Alternatives*, 2005.; E3/BPA *Olympic Peninsula Study Of Non-Wires Solutions*, 2004.; RMI/E3/Freeman/Sullivan, *Marshfield Pilot Design Report*, 2008.

- A study by the Regulatory Assistance Project in 2001 that evaluated T&D avoided costs of numerous utilities across the nation by using historical T&D investment data available in FERC Form 1. The study also presented a range of potential variation in T&D avoided costs in addition to the average cost. [35]
- A study by the ICF Consulting in 2005 that estimated avoided costs of energy supply for assessing cost-effectiveness of energy efficiency measures by utilities in New England. [36] The study provided a spreadsheet in which a utility's historical and planned cost of T&D investment could be entered in order to estimate average T&D avoided costs.
- New York Department of Public Service recently estimated avoided costs of power supply including T&D costs for upstate and downstate New York in the proceeding of New York's Energy Efficiency Portfolio Standard. [37] The study was based on old distribution marginal cost studies that were conducted around 1995 and made adjustments to those results based on the changes in various circumstances happened between then and now. Details of this study are discussed below.
- A study by Oak Ridge National Laboratory in 2003 that estimated average T&D avoided costs for the nation and PJM territory using FERC Form 1 data. [38] This study de-rated the ability of DG units to support T&D system by applying a certain assumption for a number of DG units at specific locations in T&D systems and relying on their assumption on a number of available DG units at specific locations and the probability of DG outages.

<u>Reliability: Are DG/CHP Resources a Perfect Substitute for T&D Capital Investments?</u>
Another caveat involves characterizing the treatment of DG/CHP reliability. As discussed in the overview section, DG/CHP assets must operate when they are needed to reduce the peak load. There are a number of practices/approaches to address this issue. Some of the approaches de-rate the capacity of DG units for calculating avoided T&D requirements on the grounds that a single DG unit is not likely to provide its full capacity at all times it might be needed. Other approaches recognize the full capacity of DG units. This seems to be the case with utility-owned DG units. It has been noted for example that Con Ed applies a far more rigorous reliability standard to customer owned assets seeking to serve as a T&D resource, than it does to its own assets. When constructing T&D value to be applied to DER assets it is important to recognize that there are a number of potential ways to treat these units. Some examples are presented below.

- **Demanding high reliability of DG units**: For the New York DG pilot project conducted between 2002 and 2004, a Pace and Synapse 2006 report found that NIMO, Con Ed and Orange and Rockland Utilities imposed an unreasonably high reliability standard equal to the reliability of the grid (supposedly 99.99%). In one case, NIMO rejected one bid at least in part on the basis that the DG resource could only meet 98% reliability on the area aggregate basis. [39] Further, a study by Oak Ridge National Laboratory in 2003 estimated avoided T&D for DG using a similar approach. [40] As discussed in a Pace/Synapse 2006 report, requiring the aggregated DG units to have the same level of reliability as the distribution system has; "creates an uneven playing field, first, because the pre-existing distribution system is advantaged by its diversity of generation and distribution assets – if one component fails, the system is configured to still serve load, and second, because the analysis does not include the reliability benefits of distributed generation." [41]

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[35] The Regulatory Assistance Project (RAP). *Distribution System Cost Methodologies for Distributed Generation*, 2001.
[36] ICF Consulting 2005. *Avoided Energy Supply Costs in New England*. December 23, 2005.
[37] A memo on T&D avoided cost methodology prepared by Steven F. Keller at NY DPS in January 2008. The study is not publicly available at this point since the study results are not final and subject to change.
[38] ORNL, *Quantitative Assessment of Distributed Energy Resource Benefits*, 2003.
[39] Pace/Synapse. *A Comprehensive Process Evaluation*, 2006.
[40] ORNL, *Quantitative Assessment of Distributed Energy Resource Benefits*, 2003.
[41] Ibid., p. 39.

- **Back-up generators or physical assurance**: California investor owned utilities and ConEd's targeted DSM program require the customer to drop its load whenever DG units are down (physical assurance). [42] The term for physical assurance in the ConEd's RFP is presented below:

> DG installations may be operated in parallel with the Company's system or in isolation from the Company's system by means of a transfer switch (break-before-make) to reduce load during peak periods of a selected load area. Still, proposals for DG installations operating in parallel with the Company's system will have to demonstrate that such DG installations have alternative physical means to effectuate the demand reductions offered when the DG is not operating (physical assurance), for example, the installation of customer-owned equipment or system, approved by Con Edison, that would to be used to reduce the customer's load whenever the DG is not operating. [43]

- **Monitoring and remote control**: Detroit Edison has been using utility owned mobile DG units for distribution grid support using sophisticated monitoring and control equipment. [44] As of 2006, the company has deployed about 12 projects totaling 20 MW. The company monitors DG conditions (such as oil pressure, loading level, fuel consumption and temperature) and operates and test-runs the units remotely and periodically. This approach provides the company confidence in DG operation and allows it to count on the full DG capacity for grid support.

- **No redundancy, no physical assurance**: Interestingly, while ConEd is requiring physical assurance (the functional equivalent of back-up generation) for customer owned DG in its Targeted DG program, it does not apply the same strict standard to its small generators used to defer T&D projects and to provide adequate assurance for load relief. [45] Paul Chernick of Resource Insight has observed:

> In its T&D plan, Con Edison credits the W. 59th St gas turbine—which is listed in the 2008 Gold book as having a summer capacity of just 12.4 MW— with contributing 14.6 MW of load relief to the W. 65th St. area substation No. 2, the 138-kV subtransmission feeders to the W. 65th St. and Astor substations, and the W. 1 49 St. substation. Without the W. 59th St generator, Con Edison would have found the W. 65th St. substation No. 2 to be capability-deficient through 2013. Similarly, Con Edison credits the East 74th St. gas turbines 1 and 2 (listed in the Gold Book at 19 and 19.5 MW respectively) as providing 18 and 20 MW of load relief respectively to the East 75th St. area substation and the 138-kV feeders. Without these generators, Con Edison would have determined the East 75th St. substation to be deficient through 2010. [46]

Chernick further argues that ConEdison's double standard for customer DG in the targeted program is more pronounced in that (1) Con Edison's small generators that were built around 1960s are likely to have higher forced-outage rages and failure-to-start rates than those of more-modern DG units; and (2) the generators are large by DG standards and pose more serious outage risks than smaller, more diverse DG units. The loss of load probability for one 20 MW generator exceeds that of 20 1 MW generators.

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[42] CPUC, *Decision 03-02-068*, 2003.; Tom Dossey, *Key Elements of SCE's Proposed Distributed Generation RFP*, 2004.; PG&E, *Distributed Generation and Distributed Energy Resources*, 2004.
[43] Con Edison, *Request for Proposals*, 2007, pp. 2–3.
[44] Pace/Synapse. *A Comprehensive Process Evaluation*, 2006.
[45] Chernick, Paul. *Direct Testimony of Paul Chernick Case No. 08-E-0539*, 2008.
[46] Ibid. p. 25.

### 2.2.3 T&D avoided cost estimates for New York

There are two recent estimates of T&D avoided costs for New York State. New York DPS staff conducted an analysis of avoided costs including T&D avoided costs, in the process of evaluating benefits of New York's Energy Efficiency Portfolio Standards in Case 08-E-1003.[47] Optimal Energy, Inc. also conducted a study for Orange and Rockland utilities.[48] The results of these studies are presented below.

| Area | Study | T&D value |
|---|---|---|
| Upstate | NY PSC 2009 | $33.48 |
| | Optimal Energy et al 2008 | $66 |
| Downstate | NY PSC 2009 | $100 |

**Table: 2.2.3 - T&D Avoided Costs (2008$/kW-yr)**

These estimates are indicative of *average avoided T&D costs* and were mainly developed for measuring the cost-effectiveness of energy efficiency programs. The value by Optimal Energy et al 2008 was developed using the projected embedded analysis, in which utilities use long-term historical trends as described in §2.2.2. The estimate by NY PSC 2009 was developed based on a number of recent distribution projects and the PSC staff's own judgment on potential avoided distribution costs.

The energy and demand reduction impact of energy efficiency measures are generally stable and remain in effect until the measure life expires. While some measures do not operate as long as expected in some cases, the aggregate operational reliability of energy efficiency is also generally stable. In contrast, DG/CHP technologies tend to have lower reliability than efficiency measures. Yet, with some operational arrangements such as monitoring and remote control or physical assurance discussed above, utilities have demonstrated reliable operation of DG or can expect reliable demand reduction effect from DG for distribution support. Thus, it is not unreasonable to apply T&D avoided costs developed for efficiency programs to DG/CHP while we need to understand the necessary conditions of DG/CHP for grid support (discussed above) when such estimates are used for DG/CHP. With such understanding and caveats, these estimates are indicative of average avoided T&D costs for aggressive, wide-spread DG/CHP implementation from a longer-term perspective. One could de-rate the capacity of DG when applying such avoided cost estimates in recognition of the operation of DG units.

When ascertaining whether a certain amount of DG/CHP could defer specific T&D projects and how much revenue they should receive site-specific T&D values should be utilized. For programs with the objective of identifying high value opportunities for DG/CHP to defer distribution capital investment, only a site specific analysis will identify the correct value to assign DG/CHP's contribution.

Below are presented two analyses calculating a system average deferral value.

**CASE 08-E-1003**[49]

New York Public Service Commission approved Energy Efficiency Portfolio Standard (EEPS) "Fast Track" utility-administered electric energy efficiency programs in its Order under Case 08-E-1003 on January 16, 2009. In this order, the Commission identified avoided cost values of power supply, including T&D avoided costs, for New York. These values were based on the Commission staff's investigation of avoided costs. The staff received comments from various parties including New York utilities and made modifications to its original estimates.

The staff concluded that the value of marginal transmission cost is reflected in the location-based marginal pricing (LBMP) system of the NYISO. Thus, transmission capacity cost was assumed to be zero.

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[47] New York PSC. *Order Approving "Fast Track*," 2009.
[48] Optimal Energy, *Economic Energy Efficiency Potential New York Service Territory*, 2008.
[49] New York PSC. *Order Approving "Fast Track"*, 2009.

In upstate New York, where radial distribution systems dominate, the avoided distribution cost is much lower than in downstate. Radial systems tend to be significantly oversized "to minimize the probability that a costly future rebuild will be required."[50] The Commission staff uses $33.48 per kW-year, which consists of $23.48 per kW-year for distribution substations (including trunk line feeders) and $10 per kW-year for the downstream parts of distribution (primary lines, secondary lines, and distribution transformers). The cost estimate for the substation is derived from RG&E's estimate for distribution cost in its 2002 rate case and adjusted for inflation. The $10 value is a placeholder that is to be used until future studies find better estimates.

For downstate where network distribution systems dominate distribution capital avoided costs were typically much higher than that found for radial distribution systems. The staff identified a wide range of marginal avoided distribution costs ranging from $22 per kW-year to $307, $549 and even $609 per kW-year from recent Con Edison's projects. Given that these values are significantly higher than the estimates that have been reported in the recent past, the staff decided to use $100 per kW-yr as a placeholder until a better number is estimated in future studies.

Con Edison noted that they used staff's March 2008 estimates of avoided T&D costs of $110/kW-year for New York and $55/kW-year for Westchester in their filing in case 08-E-1003. Con Edison believes Staff's estimates in that case were conservative insofar as the Company estimated a $608.86/kW-yr cost in case 07-E-0523 [51]

**<u>Optimal Energy Study</u>**

The Optimal Energy study focused on Orange and Rockland Utilities. This study used FERC form 1 data on annual additions and retirements for 1997 through 2006. As indicated in NARUC Electric Utility Cost Allocation Manual, [52] the study attempted to only include load-associated investment and O&M costs because customer related investment is not influenced by DG/CHP or any other DSM measures. In addition, the study also attempted to remove replacements of retired plant.

Marginal or avoidable T&D cost is typically estimated by the following formula for a selected period of time (usually a decade):

$$\frac{\text{avoidable capital investment}}{\text{load growth}} + \text{related operation, maintenance and overheads}$$

Optimal included as load-related 100% of additions of substation equipment and 75% of other distribution plant (FERC accounts 360, 361, 364–368), excluding services, meters, installations on customer premises, and street lighting. They also assumed each dollar of retired plant is equal to three dollars of addition given that retired plant expressed in nominal dollars in FERC Form 1 have higher present values.

The net additions tuned out to be about 330 MW of load from 1997 to 2006, averaged $312/kW-yr. Using an 11.21% real economic carrying charge, Optimal estimated about $40/kW-yr for distribution costs. Finally Optimal et al. added about $22/kW-yr of O&V expense to get to about $66/kW-year in 2008 dollars. For transmission, Optimal et al. did find a negative transmission cost which means insufficient investment was made to cover the retirement. Thus, the study assigned zero values for avoided transmission costs.

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[50] Ibid. p. 16.
[51] Ibid., p. 24.
[52] NARUC, *Electric Utility Cost Allocation Manual*, 1992.

## 2.3 REMAINING VALUES OF OTHER DG/CHP BENEFITS

This subsection inventories other benefits and costs of DG/CHP. Where such benefits are readily amenable to quantification we state the DG/CHP benefits in monetary terms, where available, in terms of levelized cost in cents per kWh.

- Avoided electricity generation
- Avoided and deferred generation capacity
- Wholesale Price Impact or Demand Reduction Induced Price Effects (DRIPE)
- Ancillary Services (system reliability)
- Backup reliability value
- $CO_2$ and Criteria Pollutant Emissions
- Power Quality
- Value of waste heat
- Hedge value

### *2.3.1 Avoided electricity generation*

Clean DG and CHP can displace and thereby avoid energy generated and sold on the wholesale market. The value of this avoided energy should be determined by energy prices in the wholesale markets or costs of marginal generation, either by DG selling energy directly at the wholesale price (for large DG units), or displacing energy a utility would have otherwise purchased or produced. New England states and New York use competitive wholesale energy markets, and therefore use wholesale energy prices to estimate avoided generation costs. Marginal generation is the generation from power plant units whose operation is affected by a small increment reduction in demand. Short-run marginal generation costs or market energy price include fuel costs, variable operation and maintenance costs and certain environmental compliance costs.

NYSERDA has been estimating avoided costs for evaluating its energy efficiency programs (called New York Energy $mart^{SM}$). As indicated above the New York Department of Public Service (DPS) has more recently estimated avoided costs of power supply in the process of evaluating New York's Energy Efficiency Portfolio Standards. [53] The table below shows the energy (LBMP) price forecast by NYISO Zone from 2009 to 2020. In addition, we estimated the levelized value of the energy prices over 12 years using a 5% discount rate, shown at the bottom of the table. While the study presents prices up to 2030, we picked the time frame from 2009 to 2020 given that there is significant uncertainty for a longer period. Note that A-I represents Upstate New York and J represents New York City.

[53] New York PSC. *Order Approving "Fast Track"*, 2009.

| Year | A-E | F | G-I | J | K | NYS | A-I |
|---|---|---|---|---|---|---|---|
| 2009 | $63.32 | $71.53 | $80.59 | $83.15 | $87.69 | $77.85 | $69.22 |
| 2010 | $62.01 | $69.93 | $79.25 | $81.54 | $85.25 | $76.22 | $67.87 |
| 2011 | $60.78 | $68.43 | $78.00 | $80.03 | $82.96 | $74.69 | $66.61 |
| 2012 | $59.58 | $66.97 | $76.78 | $78.56 | $80.73 | $73.19 | $65.37 |
| 2013 | $59.44 | $66.80 | $76.18 | $78.26 | $80.51 | $72.93 | $65.14 |
| 2014 | $59.30 | $66.63 | $75.59 | $77.97 | $80.29 | $72.67 | $64.91 |
| 2015 | $59.17 | $66.46 | $75.00 | $77.68 | $80.08 | $72.41 | $64.68 |
| 2016 | $59.31 | $66.63 | $75.19 | $77.87 | $80.27 | $72.58 | $64.84 |
| 2017 | $59.46 | $66.79 | $75.37 | $78.06 | $80.47 | $72.76 | $65.00 |
| 2018 | $59.60 | $66.95 | $75.56 | $78.26 | $80.67 | $72.94 | $65.16 |
| 2019 | $59.75 | $67.12 | $75.74 | $78.45 | $80.86 | $73.12 | $65.32 |
| 2020 | $59.90 | $67.28 | $75.93 | $78.64 | $81.06 | $73.30 | $65.48 |
| | | | | | | | |
| Levelized price | $60.28 | $67.81 | $76.83 | $79.24 | $82.02 | $73.92 | $65.97 |

**Table 2.3.1: Energy Price Forecast ($/MWH in 2008 $) by NYDPS and Levelized Price** [54]

### *2.3.2 Avoided and deferred generation capacity*

Clean DG and CHP also provide or free up generation capacity on the grid. In the short term, they can displace peaking capacity, which can be sold to adjacent grid systems. In the long term, they can delay or avoid the need to build or upgrade power plants or reduce the size of needed additions. Where forward capacity markets are established as in New York, the current or projected price of the capacity markets can be used to ascertain avoided capacity costs. NY DPS recently estimated avoided capacity costs for New York in the Order Approving “Fast Track” Utility-Administered Electric Energy Efficiency Programs with Modifications, issued and effective January 16, 2009. [55]

In this Order, the DPS staff used estimates of Long Run Avoided Costs (LRACs) in evaluating the benefit and cost of energy efficiency program proposals. A prior Order [56] had invited utilities to propose expedited Fast Track programs, and these proposals were predicated on a set of LRAC assumptions. The Jan 16, 2009 Order alters prior LRAC assumptions to insure their validity as an evaluation tool. The revised LRAC estimates were adopted in the Jan. 16 Order, and are available in Appendix 2 of the Order. The Order disaggregates cost estimates based on regions of the State, which has the effect of raising the downstate, New York City estimates and lowering the upstate estimates.

The table below shows the capacity price forecast for upstate and New York City. In addition, we estimated the levelized value of the capacity prices over 12 years using a 5% discount rate, shown at the bottom of the table. While the study presents costs up to 2030, we picked the time frame from 2009 to 2020 given that there is significant uncertainty for a longer period.

[54] Ibid.

[55] Ibid.

[56] New York PSC. *Order Establishing Energy Efficiency Portfolio Standard,* 2008.

| Year | Upstate | NYC |
|---|---|---|
| 2009 | $38.65 | $55.51 |
| 2010 | $45.77 | $120.22 |
| 2011 | $52.39 | $119.74 |
| 2012 | $58.61 | $119.22 |
| 2013 | $64.47 | $125.08 |
| 2014 | $69.98 | $121.04 |
| 2015 | $75.16 | $113.36 |
| 2016 | $80.04 | $122.29 |
| 2017 | $84.62 | $136.08 |
| 2018 | $88.93 | $137.15 |
| 2019 | $92.98 | $138.11 |
| 2020 | $96.78 | $138.98 |
| | | |
| Levelized Cost | $67.64 | $117.92 |

**Table 2.3.2: Marginal Generation Capacity Cost Forecast by NYDPS and Levelized Capacity Cost ($/KW-Year in 2008 $)**[57]

### *2.3.3 Wholesale Price Impact or Demand Reduction Induced Price Effects (DRIPE)*

In organized wholesale markets like the NYISO, NEPOOL and PJM the price of electricity is set by the marginal unit serving load. At peak times, due to the nearly vertical shape of the aggregate demand curve, small reductions in demand can create much larger reductions in price. As we reach system capacity, marginal units coming online at the peak have markedly higher costs than units somewhat farther down the supply curve. Reductions in demand created by DG/CHP units that are operating at these times may obviate the need for turning on much higher priced system generators. The savings that are created by this reduction in demand provide a benefit to all customers by lowering the market-clearing price. It should be noted that not only are the generators used at system peak very costly, they typically have very high emission rates relative to the system average. DG/CHP operating at this time may lower wholesale prices to the benefit of all customers served by that market and simultaneously reduce emissions from the high emitting generators that would otherwise be called upon to serve.

Demand Reduction Induced Price Effects (DRIPE) is the term sometimes used to describe these energy and capacity market price effects. NYSERDA has looked at energy and capacity market price effects in two recent studies:

<u>NYSERDA 2005 Study</u>[58]
The NYSERDA 2005 study estimated the wholesale energy price impact from demand reduction that affects the market clearing price of electricity. The methodology applied estimated the savings that result from lower wholesale electricity commodity prices for all kWh generated. [59] The range of the reduction was estimated at $11.7 million in 2003, to $39.1 million (in 2004$) in 2023. [60] The value was levelized at $11.51 per MWh (in 2004$) or $12.87 (in 2008$)and added to the stream of benefits in the report's Scenario # 2, one of several benefit cost analysis scenarios for individual New York Energy $mart Program initiatives.

[57] New York PSC. *Order Approving "Fast Track"*, 2009.
[58] NYSERDA, ***New York Energy $mart**[sm]* *Program Cost-Effectiveness Assessment*, 2005.
[59] Ibid. at p. 39.
[60] Ibid. at p. 23.

NYSERDA 2008 Study [61]

The NYSERDA 2008 study estimated wholesale capacity price impact, but did not estimate the market price effect because of a change of methodology. [62] The capacity market price effect estimated the value of curtailable load, which results in lower capacity costs for all purchased capacity, thereby affecting market prices. Based on the NYISO's Demand Curve, the effect was estimated to be approximately $600 per kW-year in 2007$ (about $613 per kW-yr. in 2008$) for the Con Edison service area. In other parts of New York, the cost reduction was estimated at approximately $180 per kW-year (about $184 per kW- year in 2008$). The differences were attributed to the installed curtailable load in the differing regions. Finally, the report blended these estimates for a state wide price effect of $424 per kW-year ($433 per kW-yr. in 2008$), and the effect was assumed to last for three years.

### *2.3.4 Reliability Benefits*

In general, distributed generation can increase system reliability, in the broadest sense, by increasing the number and variety of generating technologies; reducing the size of generators and the distance between generators and load; and by reducing loading on distribution and transmission lines. [63] Nevertheless, the DG system size, location, control characteristics and the reliability of fuel supply to the DG system are all factors that could have a positive or negative impact on system reliability depending on the conditions. [64]

System reliability is measured by system planners and operators with various indices including loss-of-load probability (LOLP) and customer outage data. The construction of reliability indices and the rigor and methodological consistency of data collection efforts varies over a broad range, limiting their current usefulness in assessing DG effects.

Quantifying and monetizing those benefits is beyond the scope of this study. Nevertheless, one historical example may illustrate the potential scope of these benefits. During the last wave of nuclear plant construction, single units were built as large as 1100 MW in capacity. Seabrook I is an example. At the time Seabrook I came into service, its loss became the single largest risk to the reliability of the New England grid and substantially increased the risk of system outages. To remedy this situation, the New England Power Pool had to increase the required reserve margin for every utility in New England by several percentage points. A two percentage point increase in the region's required capability would amount to something on the order of 500 MW. The cost savings implicit in reducing the size of plants and dispersing them can be appreciated from that observation.

### *2.3.5 Ancillary Service Benefits*

Ancillary services are those services that are necessary "to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system. . . ." FERC Order 888, Final Rule, 5 FERC 61,080, p. 206 ff. Examples of ancillary services include various types of reserves, scheduling and dispatch, voltage control, and voltage regulation. DG and CHP resources may deliver one or more of the needed ancillary services and the resulting economic benefits.

DG/CHP units are unlikely or unable to participate in the markets for load following, operating reserves, and dispatch and scheduling, but still may provide some ancillary service value. Some quantification examples are provided as follows:

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[61] NYSERDA, NY DPS, NY PSC, ***New York Energy $mart***[sm] *Program*, 2008.
[62] Interview with Helen Kim.
[63] US DOE, *The Potential Benefits Of Distributed Generation*, 2007.
[64] Ibid.

- The potential value of ancillary services to other electric ratepayers for PV used in the Rocky Mountain Institute Report [65] is valued at the CAISO market price range of 0.5 to 1.5 cents/kWh. [66]

- The Vote Solar White Paper [67] values ancillary services at 0.2 cents/kWh.

- The Austin Energy Report [68] evaluates the voltage regulation benefit by assuming that PV inverters could be modified to operate the desired power factor. The results suggest that although there is a range depending on how much the PV system can be depended on for voltage support, the value will always be close to 0 cents/kWh. [69]

- The MTC report by Navigant Consulting, Inc. [70] values ancillary services at 0.3 cents/kWh, based on the E3 report.

- NYISO provides payments to generators supplying black start service to cover capital and fixed O&M costs, the cost of training operators, and for testing. The payment schedule for existing generators (not for new) in the Con Ed district is based on black start and system restoration services by unit time and level of interconnection to the transmission system. [71]

#### *2.3.6 Backup reliability value*

The reliability of power without interruption can be extremely valuable to certain customers. Outages can impose serious costs to commercial and industrial customers in the form of reduced output, lost inventory, damage to equipment, loss of access to data and transactions processing, and more. Residential customers may suffer spoilage of food, additional heating costs and possible medical injury if they rely on electricity for health reasons. Critical institutional facilities such as hospitals may have to curtail services. Assessing the value of back up reliability involves assumptions of perception and customer expectations.

- An EPRI 2004 report estimates backup reliability value with the following assumptions: A sample customer perceives their backup to be worth $50,000 per year, and they need a 500 kW unit for this backup service, thus the resulting value of the backup service is $100/kW. [72]

- The Navigant 2008 report "Photovoltaics Value Analysis," cites LBNL and NREL reports that measure the benefit of increased outage support for PV with battery usage as backup reliability, with the value of the reliability of PV with battery storage ranging from 0 - 2.7 cents/kWh, depending on the needs of the customer. [73]

#### *2.3.7 CO 2, Criteria Pollutants and Green House Gas Emissions*

Green House Gas Emissions Reductions

States are beginning to ascribe a value to carbon reductions. To the extent that DG CHP creates verifiable reductions in greenhouse gases they may be able to take advantage of nascent markets for monetizing and selling this benefit.

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[65] E3/RMI, *Methodology and Forecast of Long Term Avoided Costs*, 2004.
[66] Contreras, et al., *Photovoltaics Value Analysis*, 2008, at p.13, citing E3/RMI report.
[67] Smeloff, E., *Quantifying the Benefits of Solar Power for California*, 2005.
[68] Hoff, T.E., et al. *The Value of Distributed Photovoltaics to Austin Energy*, 2006.
[69] Contreras, et al., *Photovoltaics Value Analysis*, 2008, at p.13, citing Hoff, et al Austin Report.
[70] Navigant Consulting Inc., *Distributed Generation and Distribution Planning*, 2006.
[71] US DOE. *The Potential Benefits Of Distributed Generation*, 2007, p. 4-9.
[72] EPRI. *Economic Costs and Benefits of Distributed Energy Resources*, 2004, at p. 2-11
[73] 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.

In the Order Establishing Energy Efficiency Portfolio Standard and Approving Programs the Commission found that implementation of energy efficiency programs will have a greater favorable impact on air quality than the no action alternative. [74] At Appendix 3 of this order the Total Resource Cost test was amended to include an externality adder of $15/ton for Carbon to as an estimate of the benefit of carbon reductions. Parties were encouraged to provide additional quantifications based on alternative $/ton values. $15/ton for $CO_2$ would translate into about $7/MWh assuming that marginal generation is combined cycle power plants with the average heat rate of about 8,000 Btu/kWh.

Nevertheless, this $15/ton of $CO_2$ appears to be a low value based on the potential carbon prices that would be traded under various proposed federal carbon bills. There are many studies that forecast future potential carbon prices based on proposed federal legislation on carbon regulation. Synapse Energy Economics (2008) prepared carbon price forecasts based on such studies in an attempt to present an appropriate level of financial risk associated with greenhouse gas emissions to be used for utility resource planning and other decision marking. [75] (see Table below). The 2008 Synapse Low $CO_2$ Price Forecast starts at $10/ton in 2013, in 2007 dollars, and increases to approximately $23/ton in 2030 with a $15/ton levelized price over the period
2013-2030, in 2007 dollars or $15.3/ton of levelized price in 2008 dollars. The 2008 Synapse High $CO_2$ Price Forecast starts at $30/ton in 2013, in 2007 dollars, and rises to approximately $68/ton in 2030. This represents a $45/ton levelized price over the period 2013-2030 in 2007 dollars, or $46/ton in 2008 dollars.

[74] New York PSC. *Order Establishing Energy Efficiency Portfolio Standard*, 2008, p. 67.
[75] Schlissel, et al. *$CO_2$ Price Forecasts*, 2008.

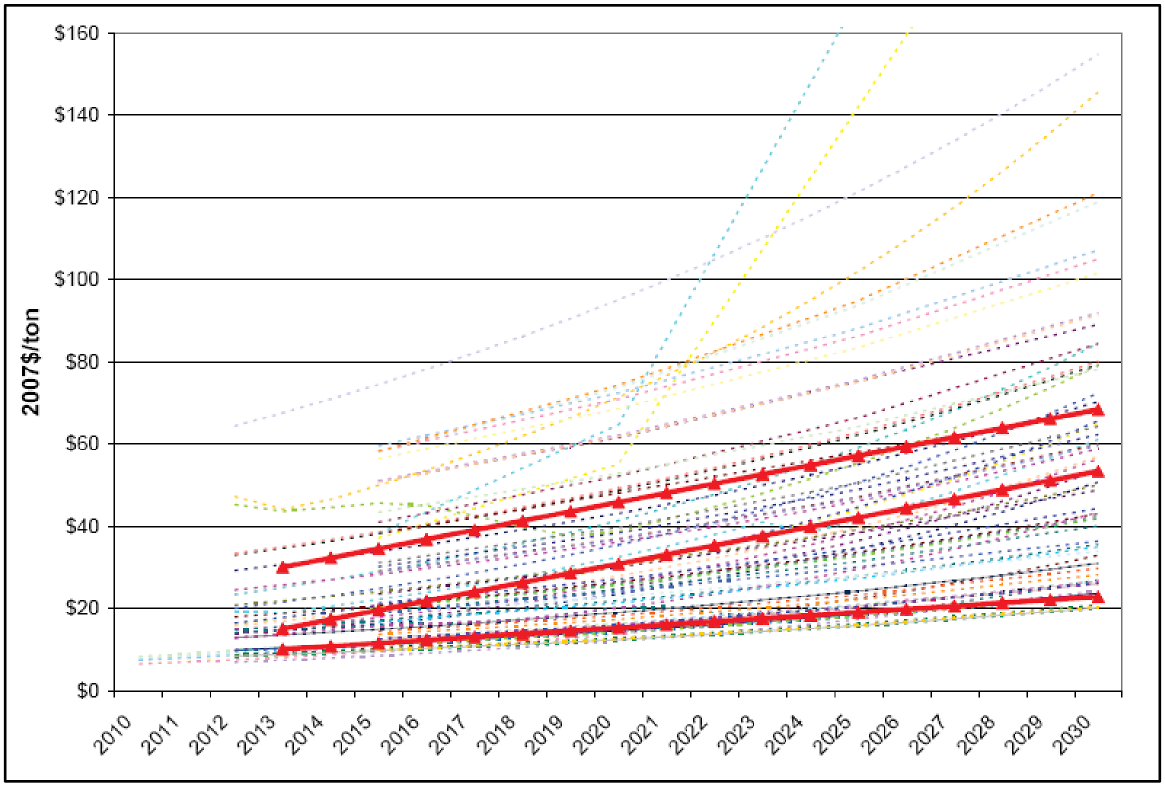


**Figure 2.3.7: Synapse 2008 $CO_2$ Price Forecasts vs. $CO_2$ Prices Used by Regulatory Commissions and Utilities in Resource Planning Analyses (2013-2030, in 2007 dollars)**

Further, it is important to note that there are a number of regulatory entities and utilities that are already incorporating carbon prices in their decision making process. In the recent IRP filing of Delmarva Power carbon prices were forecast out to 2029. In this particular analysis the base case estimate forecast a price of $12/ton in 2013 rising to over $19/ton in 2020 (all estimates in 2007$'s). The results are described in Appendix C of the filing. [76] Synapse Energy Economics (2008) also summarized such cases and found a wide range of carbon prices considered by utilities and regulators across the nation as presented in Figure above.

[76] Appendix C: Supporting Documentation for the Delmarva Delaware IRP Filing Resource Modeling, page 15 Nov 3. 2008

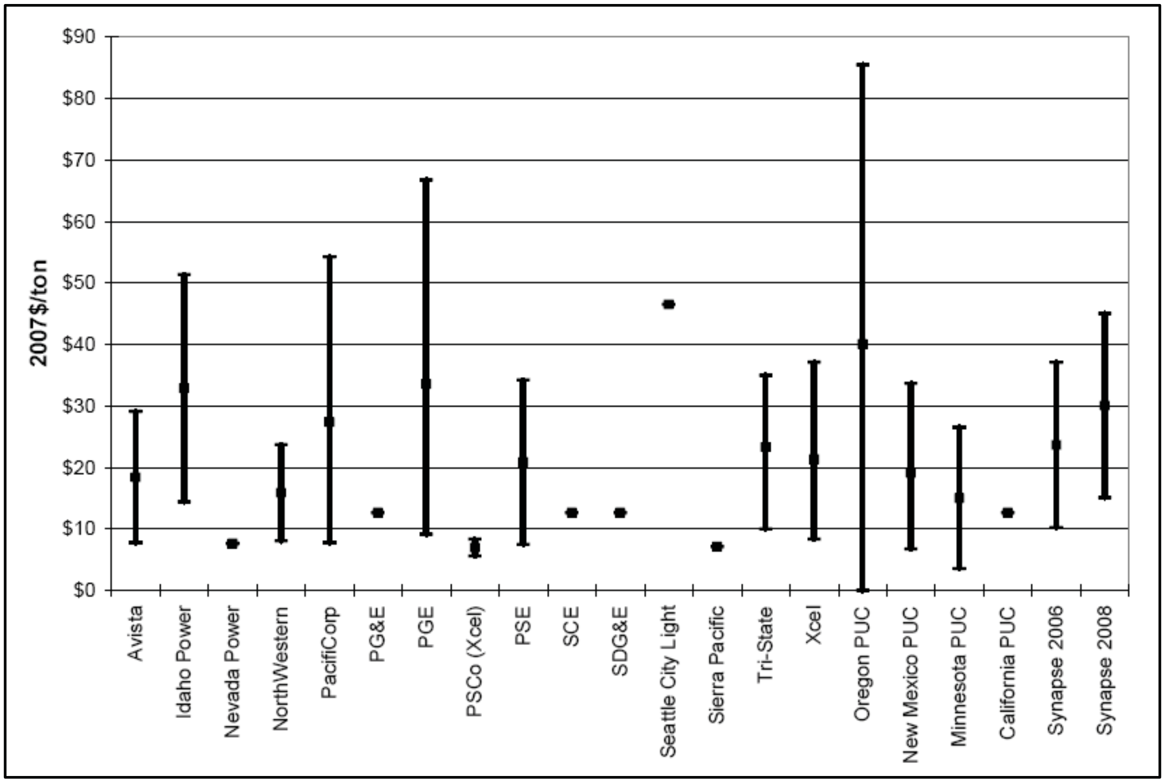


**Table 2.3.7: Synapse 2008 $CO_2$ Price Forecasts vs. Results of Modeling Analyses Major Bills in Current U.S. Congress – Annual $CO_2$ Prices (in 2007 dollars)**

The recent RGGI auctions for $CO_2$ allowances has established a trading price in the neighborhood of $3.30/ton reduced. If clean, DG assets are viewed as resources that can creates offsets to be sold into the RGGI marketplace. Owners of clean onsite generation may be able to capture a new revenue stream. This market only pertains to the electric power generation sector and to generating stations greater than 25 MW in size.

Note the level of avoided carbon prices vary depending on type of DG technologies and fuels. $CO_2$ emission rates (in lbs per kWh) of CHP units would differ from those of central station units such as combined cycle gas turbines or simple gas turbines and could be higher or lower, depending the fuels and heat rates of the marginal units. Still, given that CHP would displace on-site thermal energy needs and fuel required to provide the heat, CHP would likely result in reduced $CO_2$ emissions overall. CHP/DG technologies using sustainably harvested biomass fuels would reduce carbon emissions compared to central station generation assuming a reasonable fuel transportation radius. In contrast, emission free on-site DG such as PV and wind power will displace all of the $CO_2$ emissions in MWh of displaced generation from central stations. In summary, with the $15/ton $CO_2$ proposed by NY DPS, carbon values for DG/CHP in New York would range from zero to $7/MWh based on the cost of $CO_2$ proposed by NY PSC, depending on the technology and fuel used. Or if the carbon price would be higher than others forecast, the avoided carbon price would exceed $7/MWh.

<u>Reductions in Criteria Pollutants</u>

Clean DG and CHP can play an important role in reducing the emissions of criteria pollutants. In a 2002 study prepared for NYSERDA the authors found that installing 2,200 MW of incremental CHP over a 10 year period (2003 – 2012) would lead to the following environmental benefits:

Annual Emission Reductions in 2012

10,282 tons of $NO_x$

27,766 tons of $SO_2$

3,854,000 tons of $CO_2$ [77] **(not a criteria pollutant)**

Clean DG CHP emissions reductions are dependent upon the type of technology used, the sources of the displaced electricity and, for CHP, and the type of thermal energy that is replaced. For example, replacing aged, inefficient heavy oil boilers with very clean microturbine based CHP can create significant reductions in $NO_x$, $SO_2$ and particulates. On the other hand, if the electric generation resources being displaced are largely nuclear and hydro powered electric generation and the waste heat displaces heat from a 90% efficient natural gas boiler, then the $NO_x$, $SO_2$ and PM reductions are considerably less.

Distributed generation technologies that have fewer emissions compared to other generation resources will contribute to the benefit of avoided environmental emissions. [78] As with all generation resources, DG and CHP must comply with air quality standards, and if they generate from renewable fuels sources, may benefit from reduced compliance and permitting costs. [79] Because costs of mitigation or management of regulated pollutant emissions are included in the market price of energy, clean DG may realize cost savings as a cleaner generation source. [80]

Several studies have used a direct cost savings analysis to value emissions reduction benefits, by the following method: Emission Benefit (\$/kWh) = Market Value of Penalties or Costs (\$/kWh). [81]The market value of costs is a problematic figure to ascertain, since the market does not adequately price emission costs.

Value may also be realized by the participation of a DG generator in emission reduction credit, emission allowance or offset markets. Markets do exist for certain criteria pollutants. As of December 2008, NYSDEC had three cap and trade emissions rules designed to reduce the overall level of emissions from large industrial sources and electricity plants that generate > 15 MW:

6 NYCRR Part 204, covering emissions of nitrogen oxides ($NO_x$) during the ozone season (May–September);
6 NYCRR Part 237, covering non-ozone-season $NO_x$ emissions; and
6 NYCRR Part 238, covering year-round emissions of sulfur dioxide ($SO_2$).

In 2009 these programs will be replaced by New York State's implementation of the federal Clean Air Interstate Rule (CAIR). As of this writing, the applicable NYSDEC regulations for the cap and trade programs are;

6 NYCRR Part 243, implementing the CAIR $NO_x$ ozone season program;
6 NYCRR Part 244, which governs the implementation of the $NO_x$ annual trading program; and
6 NYCRR Part 245, which establishes the CAIR sulfur dioxide ($SO_2$) trading program.

Clean DG/CHP was eligible to earn and thereby sell emission allowances under the programs in effect through December 2008. Sites that could generate power with criteria emissions lower than the benchmark level could accumulate emission allowances under the "set aside" program in effect in New York.

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[77] Energy Nexus Group/ Onsite Energy/ Pace Energy Project. *Combined Heat and Power Market Potential For New York State*, 2002, pps. 7-7, 7-8.
[78] EPRI. *Economic Costs and Benefits of Distributed Energy Resources*, 2004, at p. 2-21.
[79] Ibid.
[80] Ibid.
[81] Contreras, et al. *Photovoltaics Value Analysis,* 2008, citing Smeloff E., *Quantifying the Benefits of Solar Power for California*, 2005; E3 and RMI, *Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs*, 2004.; Hoff, T.E., et al, *The Value of Distributed Photovoltaics to Austin Energy and the City of Austin*, 2006.

Payments in the $NO_x$ allowance markets are very volatile. Prices in some years reached and exceeded \$3,000/ton. In 2007, the monthly average settlement price ranged from \$562 to \$1,033. Still, even if the price reaches \$3,000/ton of $NO_x$, the resulting price per MWh is very small and less than \$0.25/MWh when generation from natural gas power plants is being replaced. [82]

There are significant barriers deterring the participation of smaller scale DG/CHP units from participating in these market based programs. NYSERDA commissioned a study examining the issues affecting smaller scale DG/CHP including high transaction costs, the problem of aggregation and so on. [83] [84] In recognition of these barriers and due to a distinct lack of participation by clean DER in the emission allowance set aside as of 2009, the entire allowance set aside will be reserved for NYSERDA.

Because $CO_2$ is currently still unregulated, the valuation of benefits from reduced carbon emissions can only be viewed as a societal value rather than one that can be quantified economically. Nevertheless, the Obama administration pledged to regulate carbon emissions. The U.S. EPA has been considering the regulation of carbon emissions under the Clean Air Act. [85] Further, clean DG is likely to be used as part of regional carbon emission reduction strategies going forward. [86]

### *2.3.8 Power Quality*

Power quality measures how well that power will fit within the specifications. Large or lengthy departures from power quality standards can disrupt the operation of motors, electronic devices and computers and can even harm that equipment. [87] Even brief outages can be disruptive. When distributed generation improves power quality, an additional source of added economic value occurs. Because of increasing electronic end uses by customers with personal computers, televisions and other devices, poor power quality from low voltage or other problems will have an increasingly negative impact. [88] Distributed generation may have positive impacts in this arena. These impacts are area and site specific, and are considered very small by existing research, although research in this area is ongoing. [89]

- *Optimal Portfolio Methodology For Assessing Distributed Energy Resources Benefits For The Energynet available at* www.**energy**.ca.gov/2005publications/CEC-500-2005-061/CEC-500-2005-061-D.PDF

> "We conclude that DER projects in the right locations and with the right characteristics and operating profiles can improve the performance of a given network in terms of reduced real power losses, reduced VAR flow and consumption, reduced network voltage variability and eliminated low- and high-voltage buses, reduced network stress, increased load-serving capability, and avoided or deferred network improvements in both the distribution and transmission portions of the network. We demonstrate a methodology to systematically identify these beneficial DER projects and quantify their benefits." (Page 7)

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[82] The $NO_x$ emission rate and heat rate of a typical natural gas power plant are about 0.02 lbs./MMBtu and 8,000 Btu/kWh, respectively. 1 short-ton equals 2,000 pounds.
[83] Bourgeois, T, et al. *Guidebook for Small Combined Heat and Power Systems Seeking to Obtain Emissions Reduction Credits in New York State*, 2006.
[84] Bourgeois, T, et al. *Emission Allowance Market Opportunities*, 2006.
[85] Eilperin, J. *EPA Presses Obama To Regulate Warming Under Clean Air Act*, Washington Post March 24, 2009.
[86] EPRI. *Economic Costs and Benefits of Distributed Energy Resources*, 2004, at p. 2-21.
[87] For a sample utility power quality specification, see www.rockymountainpower.net//Navigation/Navigation1891.html
[88] Ibid.
[89] Ibid.

### 2.3.9 *Value of waste heat*

Waste heat recovery improves the fuel efficiency of a DG or CHP facility, for example, by putting hot water, steam or other waste heat to use, displacing the cost of purchasing other fuel to provide that heat. Factors that affect the economic value of the waste heat include the amount of heat that can be captured and used, its quality, and the cost of the fuel being displaced. [90]

EPRI determined that up to 35% to 40% of the value of displaced fuel can be captured, depending on the technology and application.

| | | Replaced Fuel Cost ($/MMBtu) | | | |
| --- | --- | --- | --- | --- | --- |
| | | $ 4.00 | $ 6.00 | $ 8.00 | $ 10.00 |
| % of DER Energy in Fuel Recovered as Usable Waste Heat | 10% | 0.005 | 0.008 | 0.010 | 0.013 |
| | 20% | 0.010 | 0.015 | 0.020 | 0.025 |
| | 35% | 0.013 | 0.019 | 0.025 | 0.031 |
| | 30% | 0.015 | 0.023 | 0.030 | 0.038 |
| | 35% | 0.018 | 0.026 | 0.035 | 0.044 |
| | 40% | 0.020 | 0.030 | 0.040 | 0.050 |

**Table 2.3.9: Value of Waste Heat Recovery ($ per kWh). Source: EPRI (2004) Table A-6, at p. 2-9.**

In the table above, EPRI shows the range of gain per kWh generated with various displaced fuel costs and waste heat recovery potentials. When replaced fuel cost is $10/MMBtu and there is 40% waste heat recovery, there is an additional $0.05/kWh of value. This is particular example is based on heat rate of 10,040 Btu, a 1 MW reciprocating engine with a total system efficiency of 80%. [91]

Assuming the natural gas cost range from $8 to $9 per MMBtu based on an estimate provided by NY DPS (presented below) and assuming 35% to 40% of heat can be recovered, the value of replaced fuel from a unit with 10,040 Btu heat rate would be $0.035 to $0.045 per kWh.

A natural gas cost in the range of $8 to $9/MMBTU appears in line with recent estimates. The table below shows natural gas price forecasts for upstate and New York City. In addition, we estimated the levelized value of fuel prices over 12 years using a 5% discount rate, shown at the bottom of the table. While the study presents costs up to 2030, we picked the time frame from 2009 to 2020 given that there is significant uncertainty for a longer period.

[90] EPRI. *Economic Costs and Benefits of Distributed Energy Resources*, 2004, at p. 2-8.
[91] Ibid., at p. 2-9.

| Year | Upstate NY | Downstate NY |
|---|---|---|
| 2009 | $8.60 | $9.14 |
| 2010 | $8.38 | $8.92 |
| 2011 | $8.17 | $8.71 |
| 2012 | $7.97 | $8.51 |
| 2013 | $7.97 | $8.51 |
| 2014 | $7.97 | $8.51 |
| 2015 | $7.97 | $8.51 |
| 2016 | $8.04 | $8.58 |
| 2017 | $8.11 | $8.65 |
| 2018 | $8.18 | $8.72 |
| 2019 | $8.18 | $8.72 |
| 2020 | $8.18 | $8.72 |
| Levelized Cost | $8.16 | $8.70 |

**Table 2.3.9: Natural Gas Price Forecast Based on the 10/6/08 ICF/NYSERDA Interim Forecast ($/MMBtu in 2008 $)** [92]

### *2.3.10 Hedge value*

Utilities value certainty in their projections of costs. One reason is that maintaining cash or other reserves to cope with large fluctuations in power costs is, itself, an expensive task. A key aspect of this uncertainty is the uncertain future cost of natural gas. Utilities generally will need to hedge those costs, say by purchasing options to buy or sell gas at certain prices, to some degree to keep their financial risks in an acceptable range. Cutting the amount of power for which that uncertainty will need to be managed is valuable. To the extent that DG or CHP projects reduce the uncertainty in either the quantity or cost of power a utility will require, those costs can be reduced.

One methodology for estimating the value of reducing uncertainty in natural gas costs relates to the cost to providing a guarantee that electricity supply costs remain fixed. Here, the natural gas hedge value ($/kWh) = cost to guarantee that a portion of electricity supply costs are fixed ($/kWh). [93] Using this methodology, and NYMEX or LIBOR futures prices, the Navigant 2008 report had a discount factor of 0.96 in 2007 and 0.27 in 2035. [94] The Americans for Solar Power report values of the price hedge from 0.4 to 0.9 cents/kWh. [95] A second methodology relates to the value an entity will pay for risk reduction or risk free benefits.

The high end of the range of value (90$^{th}$ percentile) is a net 0.9 cents/kWh (xx cents/kWh in $2008), and the low end of the range (10$^{th}$ percentile) is a net 0.0 cents per kWh. [96] Drivers include market stability, where more value is created for a hedge when the market is volatile; and heat rates, where low efficiency increases the hedge value. [97]

[92] New York PSC. *Order Approving "Fast Track"*, 2009.
[93] Contreras, et al. *Photovoltaics Value Analysis,* 2008, at p. 13.
[94] Ibid.
[95] Americans for Solar Power. *Build-Up of PV Value in California – Methodology*, 2005.
[96] Wiser, R. et al., *The Impact of Retail Rate Structures*, 2007.
[97] Ibid.

Note this value is applicable to the extent DG technologies reduce the amount of natural gas use by the central power stations. This obviously includes renewable-based DG such as PV and wind. But also to the extent biomass prices are stable relative to natural gas as price change, it could be applied to biomass based DG units. Further, CHP could provide some hedge value if CHP reduces overall natural gas across the sector as demonstrated by the EEA Inc., ACEEE study on the impacts of CHP on gas usage in New England. [98]

## 2.4 CASE STUDIES

In this section we have attempted to identify case studies that demonstrate actual distribution utility pilots that have used DG/CHP as a substitute for distribution system capital investment. Our search was thorough but not very fruitful. What we were able to identify includes a study of the Southern California Edison (SCE) service territory, the Massachusetts Technology Collaborative (MTC) work with NSTAR in Marshfield, Detroit Edison's use of mobile generators to defer upgrades, and Portland General Electric's (PGE) Dispatchable Standby Generation Program.

### *2.4.1 Southern California Edison Service Territory*

In December of 2005, a study of two Southern California Edison (SCE) circuits was released. The study assessed the costs and benefits of DER to both consumers and distribution utilities. [99] The study focused on a 13 MW suburban circuit and an 8 MW rural circuit.

The study's first objective was to evaluate the potential to use advanced energy technology to reshape electric load curves and reduce peak demand for real circuits. The second objective was to consider how utilities and customers could benefit by guiding technology deployment and managing operations to improve grid load factors, reduce energy costs and optimize electric demand growth. The third objective was to demonstrate real benefits through the installation of an advanced energy system at a utility customer site.

The results of the study showed that considerable energy cost savings, reduction of peak demand and the ability to defer upgrades to circuit capacity on the two circuits analyzed was achievable by adding distributed generation. When the DG is optimally targeted, economic benefits could be realized by SCE, as the cost savings outweighed the potential lost revenue from lower sales of electricity. The study also showed that demand could be reduced from EE, PV and DR, resulting in deferred capacity upgrades.

To upgrade circuit capacity the traditional way would require the addition of a new 13 MW circuit on the suburban substation. SCE had recently added two 13,000 kW circuits to two separate but similar substations at a cost of about $746,000 or $57/kW (a comparatively low cost). The fixed charge rate was assumed at 12%, and the average annualized carrying cost for each 13 MW upgrade would be $90,000/year. The load growth was estimated to be 170kW for the first year. For the expected growth rate on the two circuits, this cost could be deferred a year by with a DE installation of less than 200 kW. This annual deferral avoided cost amounted to more than $450/kW of installed DER.

### *2.4.2 Massachusetts Technology Collaborative's DG Collaborative Studies*

MTC's Renewable Energy Trust coordinates and funds the Massachusetts DG Collaborative, which was established by an Order on October 3, 2002 by the Massachusetts Department of Telecommunications and Energy (DTE) in order to recommend uniform standards for interconnecting DG to the electric grid. [100] The MTC DG Collaborative brings together utilities and public interest groups as well as the DG industry, with the initial goal of contributing to interconnection standards, and later to streamline the interconnection

[98] Energy and Environmental Analysis, Inc., *Natural Gas Impacts of Increased CHP*, 2003.
[99] Kingston, T., et al., *Exploring Distributed Energy Alternatives*, 2005.
[100] See http://www.masstech.org/renewableenergy/public_policy/DG/collab_overview.htm

process and consider the role of DG in distribution planning. In the latter effort, MTC investigated how DG, EE and demand response can defer distribution upgrade projects, and considered the costs and benefits of DG projects.

Marshfield, MA

In a recent example in Marshfield, Massachusetts, the distribution utility NSTAR implemented a $4 million, 18 month pilot with targeted load reductions (3 MW) achieved through DG and EE in order to prevent or defer T&D investment. NSTAR is the largest investor-owned electric and gas utility in Massachusetts, transmitting and delivering electricity and gas to 1.1 million electric customers in 81 communities. [101] NSTAR promotes the Marshfield pilot as the first in the country to implement efficiency, direct load control, and renewable energy concurrently in order to defer distribution capacity additions.

The Marshfield pilot was run in an area where two distribution lines operate at rated capacity during peak demand hours. NSTAR had determined that if an outage occurred in either of the distribution lines involved during extreme summer peak demand conditions, the line remaining in service would likely not have sufficient capacity to serve the area's entire load while the "out of service" line was being restored Instead these lines would be required to carry more than their rated capacity, and switches would be used to isolate the fault so that as many customers as possible could still be served during the repair. Nevertheless recent growth in demand exceeded the capability of either line to carry the entire area's load requirements, and traditional distribution planning was determined to require an upgrade of both lines.

NSTAR determined that a targeted load reduction of 3 MW could delay or offset the need for upgrades to the two distribution lines involved. The 3 MW reduction would be accomplished by installing a 1 MW biodiesel generator nearby, to operate only during summer peak conditions, which was determined to only be for a minimal number of hours during any given summer. The other 2 MW of load reduction was to come from distributed resources, including EE, DR and PV located on customers' premises. The hope was that successful load reduction could defer a distribution system upgrade that otherwise would be required to meet peak load.

National Grid Summer Load Relief Program

National Grid has been actively engaged in the development of pilot projects designed to ascertain the role the distributed energy resources, including DG and CHP, might play in utility distribution system planning. Pilots were undertaken at Everett, East Longmeadow, and Brockton, MA.

In a May 26, 2006 filing letter regarding the Summer Load Relief Program for Everett, East Longmeadow, and Brockton the company stated:

> *National Grid wishes to implement this Program again in order to reduce the potential for operational or service problems in these areas during peak load periods this summer. In addition, National Grid wishes to further test whether load relief can provide an opportunity for National Grid to defer upgrades to the distribution system. Thus, the proposed Program will provide a number of benefits: (1) participating customers will receive direct credits on their bills for voluntary load reductions; (2) any reduction from voluntary load reduction will reduce the loading on the lines, possibly preventing an overload condition; and (3) the Company will gain additional information regarding customer participation in demand response initiatives and whether it can form the basis for possible future deferral of infrastructure improvements.* [102]

The question being addressed was whether or not customer side assets; distributed energy resources, could be used to control load growth on the distribution system and thereby defer or avoid the need for capital investments.

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[101] See http://www.nstar.com/about_nstar/

[102] National Grid filing Letter in Re: Massachusetts Electric Company d/b/a National Grid; Summer Load Relief Program for Everett, E. Longmeadow, and Brockton; D.T.E. 06-____ from Amy G. Rabinowitz, Assistant General Counsel, dated May 25, 2006. Page 1. Accessed on March 31, 2009 at http://www.masstech.org/dg/2006-05-26_NationalGrid_Congestion-Relief-Pilot_DTE-filing.pdf

In Everett, MA National Grid has developed a multi-asset system designed to control and manage loads on the distribution system. The suite of programs includes demand response activities, PV, some micro-CHP units and a proposed 350 kW waste to energy generator.

### *2.4.3 Detroit Edison Use of Portable Generators to Defer Distribution Upgrades*

DTE Energy and its electric utility, Detroit Edison have integrated DG into distribution planning, with their non-regulated business, DTE Energy Technologies and the energy/now™ brand. [103] One way that DTE is integrating DG is through the use of portable generators to relieve congestion on the distribution grid, deploying them rapidly when and where they are needed. The DTE program allows the utility to manage short duration peaks and address infrastructure shortfalls, while helping to improve reliability and environmental stewardship.

Detroit Edison's Customer Premium Power Program was designed to allow DTE Energy to evaluate and monitor the use of specific customer owned DG units to validate distribution benefits. In this program, the utility partnered with distribution customers to use DG as a peak shaving strategy. Customers signed up for a three-year program, paying a monthly service charge per kilowatt installed, and agreeing to retain Detroit Edison as their energy provider. Detroit Edison remotely operates the units based on systems need.

Detroit Edison has been taking a proactive approach to incorporating DG into electricity distribution since 2003. The company began applying DG for distribution system support in the summer of 2002, when growing loads were stressing several areas of their system. In that year the Detroit Edison operated several mobile DG units for short periods of time to stabilize its system. Based on the success of these deployments, Detroit Edison has fully incorporated DG into distribution system, even adding dedicated DG staff to its distribution planning department and including DG in its capital budget planning. Detroit Edison has found DG to be an effective way to deliver "just-in-time" and "right-sized" distribution capacity to resolve smaller shortfalls while minimizing the initial capital outlay.

To date, Detroit Edison has deployed 12 distribution DG projects totaling around 20MW. Included in these projects were three used in an intentional islanding and a leased customer generator used to manage loading on an overloaded circuit. Most of the projects are considered temporary installations, designed to operate until system upgrades have been completed (from 1 to 5 years). Still, the company has also established 18 longer-term DG projects (totaling 10 MW) at customer sites, through its Premium Power program. Though their primary goal is to provide premium power to customers, these projects provide some distribution system benefits as well. Detroit Edison has relied primarily on diesel and natural gas fueled engines, however they have also installed several demonstration projects utilizing fuel cells, photovoltaics and flow batteries.

The DOE 2007 study on the Potential Benefits of Distributed Generation describes an example provided by Hawk Asgeirsson where Detroit Edison had a 500 kW capacity shortfall. [104] The $50,000 cost of a traditional upgrade was based on new capacity of 2500 kW – an amount determined necessary to accommodate future load growth, an investment that cost $20/kW. Because the actual capacity shortfall was only 500 kW, or one-fifth of the traditional capacity upgrade, the true cost of that traditional upgrade was actually $100/kW.

### *2.4.4 Portland General Electric – Dispatchable Standby Generation Program*

Portland General Electric encourages customers with standby generators to run them for the utility for 400 hours a year in their Dispatchable Standby Generation program. [105] The goals of the program are to

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[103] Asgeirsson, H., R. Seguin. *DG Comes to Detroit Edison*, 2002.
[104] US DOE. *The Potential Benefits Of Distributed Generation*, 2007.
[105] http://www.portlandgeneral.com/business/large_industrial/dispatchable_generation.aspx

improve reliability, help meet peak demand, and ease the strains associated rapid growth in the high technology sector in the Portland suburbs. Under-utilized generators designed for standby service for occasional outages are turned on, with the utility paying for maintenance and fuel expenses, greater controls, power quality monitoring systems and upgrades including switch-gearing. PGE provides also for the costs of safe interconnection to the grid, and maintenance on the generators and network connections. In the case of the outage, the customer owned generator functions as it normally would, providing back up power to the customer.

[*Pace has contacted PGE to ask if they have collected any internal information that may show what affect this program has had on avoiding capital investments to their distribution system*.]

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http://www.portlandgeneral.com/about_pge/regulatory_affairs/pdfs/schedules/sched_200.pdf
http://pepei.pennnet.com/articles/article_display.cfm?article_id=95211
Mark T. Osborn is manager of PGE's Dispatchable Standby Generation program Power Engineering March, 2001.

# 3 Gap Analysis: Barriers to Obtaining DG/CHP Benefits

Despite efforts on the part of numerous stakeholders and interested parties to accelerate the deployment of cost effective DG and CHP, and to simultaneously capture the accompanying energy and social benefits of these technologies, growth in the DG/CHP markets has remained slow. Many analysts believe that penetration rates remain well below the economic potential that the industry appears to offer, especially when considering reasonable tests of economic efficacy.

Proponents argue that the low number of operating DG and CHP installations, when measured against levels of apparent economic viability, is partially due to numerous barriers inhibiting their development. These barriers are not only limited to higher initial capital costs, but also relate to various policy and regulatory issues including, but not limited to:

1. Lack of standardized interconnection rules and interconnection charges
2. Standby charges
3. Stranded assets and exit fees
4. Existing approaches to air quality rules and regulations
5. Siting restrictions
6. Financial barriers
7. The inability of CHP to capture the economic value of benefit streams it creates

In a 2007 national level study the US Department of Energy sought to quantify the cost and the consequent impact on economic payback of a variety of measures that have been employed in various jurisdictions around the country. [106] The DOE 2007 study provides an example of DG barrier costs below in Table 5.1. [107]

| Impediment Description | Barrier Cost | Simple Payback Impact (yrs) |
|---|---|---|
| Standby Charge ($6/kW/mo) | -$72,000 annually | +1.5 |
| Non-Coincidental Off Peak ($12.5/kW/mo) | -$127,000 annually | +3.3 |
| Interconnect Charges | $300,000 upfront | +1.0 |
| Load Retention Rate | -$245,000 annually | +2.4 |
| Exit Fee | $1,000,000 upfront | +2.9 |

**Source: Table 5.1 Impact of Rate Design on Distributed Generation** [108]

These issues are not entirely representative of the current state of the market for DG/CHP in New York. In fact, New York State has gone a considerable way to addressing many of the barriers that seem to have unduly slowed the growth of DG/CHP into the marketplace.

In 2003, New York State initiated a thorough review of the existing standby rates, and the stranded cost charge portion that had been collected in the rate was removed. While the result of the proceeding was not entirely welcomed by the DG/CHP development community, changes made at that time were certainly in the right direction for most of the state's utilities. Subsequent to that decision, National Grid, the remaining utility with the highest standby charge significantly reduced the levy.

[106] Ibid.
[107] Ibid.
[108] Ibid.

Despite the progress that New York has made with certain regulatory and business practices, policy decisions continue to be an issue for the development of a more robust market for DG/CHP applications in the state. Barriers to the development of more robust markets for DG/CHP are numerous, and include:

- Higher initial capital costs
- Acquiring the financing and competing against other capital investments that are more central to the end-users core business
- Disincentives that the utility faces 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
- Uncertainty about future gas costs and the spark spread
- 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
- An inability to capture and monetize certain value streams that the DG/CHP facility creates (e.g. criteria pollution reduction, greenhouse gas reduction, T&D congestion benefits, and so on)

# 4 OVERCOMING BARRIERS: A CASE STUDY IN CONNECTICUT

The issues impeding the development of broader markets for DG/CHP are many, and no single policy measure or regulatory fix will be sufficient to move the market in a dramatic manner. Several states have taken a comprehensive approach to reducing obstacles impeding market development. Still, no state has been more aggressive than Connecticut in marshalling an array of incentives to address a broad range of the existing barriers. For that reason, to illustrate remaining barriers, we will review the Connecticut program, initiated in 2006 and under review for significant revisions as of January 2009.

In 2005, the State of Connecticut passed "An Act Concerning Energy Independence" (Act). [109] The purpose of this Act was to assist the State in reducing certain federally mandated congestion charges. The objective was to utilize distributed energy resources, in conjunction with other capital investments, to reduce charges associated with congestion on the transmission system within the state.

**Capital grants;**

CHP located in Southwest Connecticut $500/kW
CHP located in non-Southwest Connecticut $450/kW

**Low interest loans;**

The interest rate will be 1% below the customer's applicable rate or no more than the prime rate.

**Discounts for the cost of natural gas;**

Under this aspect of the program, certain distribution charges will be waived.

**Standby Charges;**

An exemption from certain electric costs for backup service.

**Utility Incentives;**

$200/kW for resources operational before January 2008, $150/kW for resources operational during calendar year 2008, $100/kW for resources operational during calendar year 2009 and $50/kW for resources operational thereafter

**New Value Stream;**

Creation of a Class Three Resource (energy efficiency and CHP) and a requirement that the utilities provide 1% of standard service offerings from these resources by 1/1/2007. This percentage requirement increases by 1% per year in each of the following three years, reaching a level of 4%.

The Act created a multi-faceted incentive plan that was designed to deliver a sizeable amount of new customer sited distributed resource within a short time frame. The incentives addressed panoply of barriers including;

1. Reducing the initial capital cost barrier via a capital grant
2. reducing the financing barrier via a low interest loan program
3. reducing the disincentive utilities fact by offering a utility incentive of $200/kw for customer-side distributed generation operational by January 1, 2008, $150/kw for resources operational within calendar year 2008, declining to $100/kW in 2009 and $50/kw for resources operational from 2010, and thereafter
4. reducing the input fuel costs waiving certain gas distribution charges
5. creating an exemption from certain electric costs for standby service

[109] House Bill No. 7501, Public Act No. 05-1.

6. creating a new revenue stream by instituting a new Class Three Resource and a new distribution utility resource portfolio requirement. Class Three resources were defined to include energy efficiency and CHP resources. The utilities were obliged to get 1% of their standard supply service from these resources beginning January 1, 2007. This percentage requirement increases by 1% per year in each of the following three years, reaching a level of 4%.

# 5 References

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

DG Business Models
Task #2

Prepared for the

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## NOTICE

**ABSTRACT**

This is the second in a series of four task reports and a final report prepared by Pace Energy and Climate Center and Synapse Energy Economics (Project Team) for NYSERDA under the terms of NYSERDA Contract #10472. This report develops the operational and programmatic elements for three business models designed to encourage the deployment of Distributed Generation / Combined Heat and Power (DG/CHP) by distribution utility deployment considering the utilization of DG assets as an alternative to traditional distribution capital expenditures. The models specified in the Scope of Work are: (i) the Utility Ownership Model, (ii) the DG Development Zone Model, and (iii) the Refined Request For Proposal (RFP) Approach.[1]

In addition to providing the operational and programmatic elements of each model, this report describes associated implementation issues as well as the potential risks and benefits from each model. This task report presents case studies illustrating how the various elements contained in the three models have been put into operation in the field and to reveal best utility and regulatory practices.

There is very limited practical experience with DG/CHP as a substitute for utility distribution system investment, rendering conclusions about best utility and regulatory practice premature. In this task report the Project Team developed the general structure of three possible business models. To the extent possible we have incorporated the limited existing base of case study experience; the case studies are intended to help anticipate the most problematic issues that are likely to arise with each model type, and to help illustrate the distinct benefits that each type might offer.

This task report should be read in tandem with the Task #3 Report: Comparative Analysis of DG Implementation Models, which supplements this section with a comparative analysis of the most critical issues associated with each of these three approaches. In particular, Task #3 assesses the following issues for each of the three models:

- Regulatory Burden And Management Complexity
- Project And Program Cost
- Ease Of DG Integration
- DG Relocation Flexibility, Deployment Lead Time
- DG Interconnection
- Reliability
- DG Market Development
- Meeting Utility Renewable Portfolio Standards (RPS)
- Resource Integration

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**KEY FINDINGS**

1. DG/CHP can serve as a substitute for distribution capital investment – when sited in the right locations, operating at the right times and offering the required level of reliability.
2. The paramount concern of the utility is safe and reliable operation of the distribution system whereas the DG /CHP owners are primarily interested in economic operation at their site. This can create some complications in program design, but is not an insurmountable obstacle.
3. Where the objectives of the utility (reliability) and private owner (economics) are not entirely compatible, they can be harmonized with some mix of physical and operational controls, contractual arrangements and incentives or penalties.
4. Distribution system capital cost savings benefits of DG are typically not captured in existing markets. Utilities may internalize the benefit by owning the DG asset themselves, or create a market (via RFP process or incentive payments) that compensates private sites for this otherwise non-market benefit.
5. The utility owned solution internalizes the benefits of the DG asset, while maintaining a high level of utility control and without the additional time and resource costs of creating a market, executing contracts and marketing programs.
6. Still, the utility owned solution raises questions of market power and perceptions of unfair competitive advantage.
7. Creating private market solutions may require more time and costs, but may yield innovative solutions that otherwise would not have been conceived.
8. The existing distribution planning process in large measure does not contemplate DG solutions. Consequently:
    a. modeling tools that would identify DG investments as cost-effective solutions are not well developed,
    b. forecasting methodologies that predict high-value DG deployment opportunities based on network loading, equipment ratings and demand projections are typically not employed, and
    c. program budgets that would identify DG alternatives are not in place.
9. The types of capital investments potentially addressable by DG projects has not been inventoried and prioritized in a manner facilitating comparative analysis of DG deferral relative to traditional solutions (e.g. load growth related investments, strategic business operations related, replacement of antiquated equipment and processes with new methods).
10. Where utility capital budgets are growing and putting increasing pressure on rates over time, utilities may consider private investment in the form of customer owned-DG assets as a substitute for traditional utility solutions.

## SUMMARY

This task report develops three business models that enable utilities to consider the use of DG assets as an alternative to traditional distribution capital expenditures. These three models represent general approaches that would allow utilities to incorporate DG into their distribution planning process as an alternative to traditional distribution system capital expenditures.

In Section 1, the Project Team critically reviews the economics and legal issues for the existing state policy regarding utility ownership of power generation in light of current market and regulatory realities. The Project Team also analyzes the impact of utility ownership of DG on the wholesale energy market, power businesses and the DG industry. This involves an exploration of market power issues associated with the utility's ability to leverage its control of the distribution network to unfairly benefit its DG businesses. It also involves an investigation of utilities' perceived unfair advantage over other wholesale energy providers resulting from the utilities' guaranteed recovery of prudently incurred capital investments.[2] These models are supported by a number of case studies included in Appendix 1.

Section 2 presents two models that facilitate the development of customer-owned DG resources as an alternative to distribution system upgrades. In each of these models, utilities play an enabling role in encouraging customer-ownership of DG. The structure of each model is described individually, followed by an examination of critical issues relevant to both models. These models are supported by a number of case studies included in Appendix 2.

In the High Value DG Development Zone Model, the Project Team critically reviews the elements of a business model under which the utility would offer a posted incentive price for new DG deployment in geographically targeted development zones. It considers the practical elements of implementing this approach, such as defining the zone, setting incentive levels, and ensuring that incentives are paid only upon a threshold level of DG penetration sufficient to defer or avoid the capital project.

In the Refined RFP model, the Project Team proposes a refined version of the RFP process for eliciting a market response to distribution system needs identified by the utility. The analysis includes options to mitigate or resolve problems identified through a pilot program, initiated by the New York State Public Service Commission (NYSPSC) that explored the use of an RFP process to secure DG resources as an alternative to utility distribution investment.[3] The value of distribution system investment deferral ranges in some areas from \$200 kW/year to \$800 kW/year. In order to capture some of the savings for the utility and its ratepayers, the DG assets would probably be acquired at a price resulting in some measure of shared savings between the company and the entity receiving the incentive. At the upper end of this value distribution, utilities could offer very attractive incentives and, at the same time, realize significant ratepayer or shareholder benefits.

Note that DG/CHP asset development typically requires a long-term planning horizon. Therefore, the subset of projects that can potentially be deferred is likely to consist of those that do not need near term attention, rather can be in place in 36 months or more without sacrificing local reliability. Projects with the longer term time frames for implementation by their nature are probably not at the extreme high end of the distribution of avoided cost savings.


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[2] 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.

[3] In NY PSC Opinion No. 01-5 2001, the New York Public Service Commission directed New York's investor-owned distribution companies to implement a three-year pilot program designed to test whether distributed generation could cost-effectively defer the need for significant investment in distribution system infrastructure.

# 1 UTILITY OWNERSHIP MODEL

## 1.1 MODEL OVERVIEW

The utility owned DG business model is one where a distribution or vertically integrated utility, in its distribution planning process, actively seeks opportunities for deployment by the utility itself, of cost-effective DG solutions, to alleviate grid congestion and to defer or avoid the construction or upgrade of distribution system equipment. The model also assumes utilities receive a regulated return on their DG investment, which is critical for a model to make economic sense. The model may take any of the following three forms:

- A utility owns and operates 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; or
- A utility owns and operates DG on a customer site on either side of the retail meter; or
- A utility owns DG control and monitor equipment, such as inverter and meter, at a customer site.

Detroit Edison operates an example of the first type of program. The company owns, deploys and operates mobile DG units (e.g., 1–2 MW trailer-mounted diesel or natural gas motor-generator sets) along its distribution system to alleviate local transmission and distribution (T&D) system congestion and in some cases to defer or cancel the need to build or upgrade distribution system equipment. Likewise, in Denning NY, Central Hudson Gas and Electric owns and operates a 1 $MV_A$ generator connected at the distribution level. The generator provides a reliability benefit to the 550 residents (65 residential, 1 commercial customer) in an area prone to frequent local outages. Central Hudson selected the DG solution after investigating the cost of building a new distribution feeder and tapping into another utility's distribution system.

Austin Energy in Texas operates an example of the second approach; it owns and operates combustion turbines at two sites, one a hospital and the other an industrial park. In addition, a number of utilities including National Grid in Massachusetts, Pepco in Maryland, and Southern California Edison recently proposed to own and operate distributed PV units. These also fall under the second form of the model. Finally, a few utilities have proposed to own DG related equipment, including Public Service of New Hampshire and Chelan Public Utility District (SEPA, 2008). Some of these cases are discussed in greater detail in the Case Studies section below.

Under any of the three versions of this business model, utilities may need to begin by hiring or expanding internal staff to work on DG projects. Such internal staff will need to be familiar not just with DG interconnection, but also with overall DG technologies, installation, and operation and maintenance. A utility might employ in-house staff to perform project engineering, design, installation, operation and maintenance, but could also contract out these tasks. Utilities would then identify, far in advance of potential distribution projects, the potential for DG projects along the distribution system or at customer sites where DG could defer distribution projects. In an alternative scenario, if a utility finds that proposed distribution upgrades are not going forward as planned due to community opposition, budget constraints, or other reasons, the utility could deploy DG under its ownership to buy time for distribution projects.

Occasionally, utility-owned DG can be sited on utility-owned land, such as on property where a substation is located. Nevertheless, when seeking to use non-utility land or a customer site for DG, utilities will need to address zoning and other local regulation, engage in community and customer outreach and, possibly, negotiate lease agreements with local governments or customers. Where noise and pollution are a public concern, utilities will need to take steps to mitigate these and obtain the required permits.

Finally, utilities may need to file regulatory documents to seek siting approval for DG installation (although in some jurisdictions mobile units or other kinds of DG may not require such approvals), and go through the process of seeking rate recovery for the costs of DG in general rate cases or special proceedings. There, they will likely need to demonstrate that their investment was prudent, in the public interest, just and reasonable in order to obtain rate recovery, including return of and on the DG investment.

## 1.2 THE PROHIBITION AGAINST UTILITY OWNERSHIP OF DG IN NEW YORK: PAST, PRESENT AND FUTURE

### *1.2.1 Utility Ownership of DG in New York*

In 1996, the NYSPSC initiated a proceeding that restructured the electric utility industry in New York State, fundamentally changing the market and opening the industry to competition (NYSPSC, 1996). The NYSPSC proceeding did not specifically prohibit a distribution utility from owning generation resources, but directed the investor owned utilities to divest their existing generation in order to create a competitive generation market. As a result, utilities generally divested their generation resources, with the exception of some small hydro generation, Con Edison's steam generators, and certain nuclear power plants (which were subsequently divested).

The question of utility ownership of generation has resurfaced in subsequent proceedings, with decisions on utility ownership determined on a case-by-case basis. The principles applied in those cases provide some useful insight for examining the circumstances under which utilities can own DG for the purpose of distribution system planning.

The most relevant principle for the ownership of DG by utilities is stated in the Vertical Market Power Policy (VMPP) Statement of 1998, where the NYSPSC stated its policy position on a T&D utility affiliate owning generation.[4] While the VMPP statement provided that generation divesture is "a key means of achieving an environment where the incentives to abuse market power are minimized," it also stated that the ownership of generation by a T&D company is allowed if there is a demonstration of "substantial ratepayer benefits, together with [market power] mitigation measures" (NYSPSC Case 96-E-0990, 1998). The VMPP has been relied upon to examine the appropriateness of generation divesture and ownership in past cases. Recent examples include the National Grid acquisition of KeySpan in 2007 and the Iberdrola acquisition of NYSEG and RG&E in 2008.

In contrast, there are only a handful cases since restructuring that involved utility ownership of DG. While the VMPP statement was not cited in those cases, its spirit was reflected. Brief overviews of two such cases are provided below:

- In Opinion No. 01-5, the NYSPSC directed New York's investor-owned distribution companies to implement a three-year pilot program designed to test whether distributed generation could cost-effectively defer the need for significant investment in distribution system infrastructure (NYSPSC Case No. 00-E-0005, 2001). The pilot focused on customer owned DG projects, but allowed utilities and utility affiliates to bid utility owned DG projects. It appears that this reflects NYSPSC's recognition that utility ownership of DG may provide some public benefits. Still, NYSPSC did not comment on utility ownership of DG in Opinion No. 01-5, and the recommendation report that NYSPSC endorsed in the opinion did not discuss utility ownership of DG resources in detail (other than the mention of one stakeholder who claimed that utility ownership allows for realization of the full benefits of DG). The recommendation report, however, did clearly state that utility affiliates are allowed to participate in the pilot provided that "utility does not extend preferences to its affiliates in violation of code of conduct requirements" (PSC Case No. 00-E-0005, Appendix B, 2001).
- In the April 2, 2010 Renewable Portfolio Standard (RPS) Final Order, NYSPSC, along with various stakeholders, reviewed the RPS customer-sited tier program to address the geographic imbalance between the regions of the state from which System Benefits Charge (SBC) money is collected, and the regions where renewable energy projects are installed with SBC funds (RPS Order, Case 03-E-0133, 2010). The order also examined utility ownership of PV as a possible eligible renewable energy resource option for the proposed customer-sited program in downstate New York. In the order, the NYSPSC stated that "the retail distributed solar photovoltaic market is demonstrably competitive and utility involvement in the market, at this time, does not appear necessary to address any deficiencies" (RPS Order, 2010). Still, NYSPSC also stated that "there may be merit in allowing utilities to participate further in this program, at a later date, if it were to be found that private investment is not available or sufficient in areas where utility ownership may

[4] The issues associated with vertical market power will be discussed in greater detail below.

be better targeted, more cost-effective and beneficial" (RPS Order, Case 03-E-0133, 2010). The order also emphasizes that utility ownership "will require careful consideration to ensure that such a structure is in the best interest of the ratepayer and that utilities are not able to monopolize any market segment" (RPS Order, 2010).

Opinion No. 01-5 was not explicit concerning the circumstances under which utility ownership of DG is appropriate. Nevertheless, the April 2010 RPS Final Order is more clear. The case concluded that while utility ownership of DG is not prohibited or illegal, it would be challenging for NYSPSC to approve "at this time." As stated in the April 2010 order and the VMPP statement, a utility needs to demonstrate that utility ownership of DG provides a substantial public benefit, does not harm competition and provides measures to mitigate market power. The order states that though not impossible, demonstrating the benefits of utility ownership relative to customer owned projects would be a challenge, particularly because there are few customer projects developed in the downstate area. Still, where utilities own DG-related equipment such as meters, inverters and controls, with the customer owning the DG resource itself (as the third form of the utility DG ownership proposed here), the benefits of DG can be recognized without requiring such a demonstration.

### *1.2.2 Market Power and Unfair Competitive Advantage*

Two major issues arise when utilities own DG assets that do not arise when utilities own only DG-related equipment such as meters, inverters, and DG control units. The first issue relates to vertical market power briefly discussed above in relation to the VMPP Statement. The second issue relates to a perceived unfair advantage over other wholesale energy providers and other solar PV providers, in that a distribution company's DG business may enjoy advantages not available to other market participants.

**Vertical Market Power.** Vertical market power occurs when an entity that has market power in one stage of the production process (e.g., distribution and transmission) leverages that power to gain advantage in a different stage of production process (e.g., generation) (PSC, 1998). In a case where utilities own DG assets, vertical market power would occur where the utilities (e.g., New York IOUs) take advantage of their monopoly in T&D in their territories (or have the ability to do so) in order to unfairly benefit their DG businesses. The following examples are helpful to understand the exercise of market power by T&D utilities:

- "[A] T&D company has an incentive to make entry by generators into its own territory difficult, and therefore, expensive for a new entrant by either delaying or imposing unrealistic interconnection requirements…" (PSC, 1998).
- "The affiliate's generator is on the high cost side of a transmission constraint and the T&D company has the ability to influence the transmission constraint. The T&D company has the incentive to retain the constraint to keep the market price high on the high cost side of the constraint" (PSC, 1998).

The vertical market power issue can be alleviated through appropriate rules and standards established by the NYISO, FERC and NYSPSC; however, such rules and standards might not completely eliminate the possibility of market power. The impact of DG on the distribution system is not fully understood even by utilities, and the lengthy process of examining the impacts of DG on the grid has historically caused significant delay in the interconnection of DG to the distribution system. Still, it is important to recognize that if utilities are allowed to own DG, it will provide an opportunity to better understand the impact of DG on the distribution system. This may result in a more standardized and efficient interconnection process, and a more precise assessment of DG benefits.

The issue discussed in the second example, where a utility maintains, creates, or increases a transmission constraint (e.g., by building less transmission capacity than is optimal), may be of even greater concern than vertical market power. In this situation, the transmission constraint will (or could) raise the wholesale market price of energy and capacity available to its generation resource. Nevertheless, it seems likely that this problem is insignificant for smaller scale DG/CHP and renewable generation for the following reasons:

(1) Because the primary goal of DG is to meet on-site or local demand (in the case of stationary DG units) or alleviate T&D constraints (by mobile and other types of DG) in the utility DG ownership model, the company may have little incentive to exercise market power to influence wholesale market price by retaining transmission constraints.

(2) DG/CHP resources are small in capacity relative to the size of the wholesale markets. While the total collective DG capacity could become material eventually, limiting the purpose of DG ownership to T&D support would limit the collective size of fleets owned by the utility.

It is important to note that the 1998 Vertical Market Power Policy Statement allowed the combined vertical ownership of generation by T&D utilities where there is a demonstration of substantial ratepayer benefits and measures to mitigate vertical market power risk. Limiting the total size of DG ownership, as mentioned above, is one approach to mitigate vertical market power. In addition, when utilities own and use DG for T&D support, it is likely to provide benefits to the ratepayers and renewable energy industries in the form of lower distribution related cost and lower DG cost. Lower distribution costs can be achieved because utilities are best situated to support T&D and to defer T&D investment. Significant DG cost reduction may be possible because of utilities' bulk purchasing power and long-term financing.[5]

**Unfair Competitive Advantage? The Impact of Utility Owned DG on DG Markets.** The second major issue arising from utility DG ownership, the perceived unfair advantage over other wholesale energy providers, stems from the utilities' rates typically being set to permit recovery of and on investments through the rate base (subject to prudence and used and useful standards). This policy, it is sometimes asserted, appears to give an unfair advantage of the utility over private companies because private companies' business is not similarly protected. Private companies can be divided into two distinct groups, the first of which is wholesale generators such as independent power producers (IPP), and the second of which is private DG project developers.

Wholesale generators or IPPs are typically private companies without cost recovery from captive ratepayers via regulated rates. In the deregulated energy and capacity markets in New York, wholesale generators are likely to object to generation ownership by utilities. Still, if the size and purpose of utility-owned generation is limited, such as when utilities seek to support T&D or promote renewable generation, then the concerns of competitive wholesale generators may be mitigated. Nevertheless, if DG developers or aggregators of DG become more active in the wholesale markets, the presence of utilities means a smaller share of business activity available to the private market. Utilities would then need to demonstrate that their ownership creates ratepayer benefits in excess of that available from private providers, and that utility ownership will be subject to market power oversight and mitigation measures.[6]

The threat of competition is a major issue affecting DG project developers that can be mitigated to a great extent by limiting DG ownership to a maximum capacity and location and providing market players with ample business opportunities.[7] One model would have utilities using their own property to site DG projects, while contracting out engineering, procurement, and construction (EPC), as well as maintenance work to private companies.[8]

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5 See examples of utility PV programs by NGRID and Southern California Edison in the Case Studies Section.

6 The utility contribution to the development of DG markets may be beneficial to private companies if it reduces the price of DG equipment in the long term by increasing the size of the DG market. Also, if a utility becomes more familiar with DG interconnection, that will help others interconnect to the grid more easily.

7 As recommended by the Solar Alliance, 2009. Also note that Massachusetts allows utility ownership of PV, limited to a maximum capacity of 50 MW per company.

8 Without an initiative by a utility to own DG, it is unlikely that DG will be installed on the utility's property.

# 2 CUSTOMER OWNED—UTILITY FACILITATED MODELS

The Refined Request For Proposal (RRFP) model provides a mechanism for utilities to promote deployment of customer-owned DG resources in high deferral value locations. The RRFP model is an adaptation of a 2002 New York pilot program for integration of DG in utility system planning.

**Key Elements of the RRFP Model:**

- Independent third party and utility responsible for selection process
- RRFP limited to areas where optimal DG/CHP economics exist
- Utility or customer provided with operational influence or control over the resource
- Other energy resources allowed to be bid with DG/CHP

## 2.1 RRFP MODEL DEPLOYED IN 2002 PILOT PROGRAM

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 were selected by the respective utilities as the least cost option. Over 75% of the RFPs that were issued did not receive a bid.

In 2006, the Project Team performed an independent evaluation of New York State's DG Pilot Program, described in a report entitled "*A Comprehensive Process Evaluation of Early Experiences Under New York's Pilot Program for Integration of Distributed Generation in Utility System Planning*" (2006 Report). The RRFP model presented here incorporates lessons learned from the 2006 Report to develop a refined approach that is more responsive to market conditions. The 2006 Report offered the following eleven recommendations to the PSC on ways to improve the existing program or a future program:

1. Limit mandatory use of RFPs to utility service areas with attractive DG economics
2. Consider a greater role for distribution utilities in project development
3. Initiate collaborative process with stakeholders for development of best practices
4. Experiment with cooperative management of bid review process with third party
5. Allow DG to be bid in combination with other distributed energy resources
6. Explicitly allow commitments for load shedding in lieu of redundant DG capacity
7. Provide greater transparency of the value of deferral to the distribution utility
8. Encourage aggressive utility co-marketing of DG program to large customers
9. Utilities should not automatically foreclose post-bid negotiations
10. Explore synergies between local utilities and NYISO in relieving grid congestion
11. Provide parties with greater guidance on the evaluation of reliability

The following sections incorporate these recommendations to structure an enhanced business model available to NYSPSC, should it decide to re-evaluate an RFP program as expressed by the page numbers in parentheses above. In particular, the RRFP proposes mechanisms that establish better congruence between distribution needs and sites where DG makes the most economic and technical sense; allows adequate lead time for preparing bids and securing host sites; provides greater transparency of 'price to beat' for wires solutions; reduces transaction costs; sets appropriate standards for required DG reliability; and addresses perceptions of utility bias in favor of its own "bid." An updated RFP program may find greater acceptance in the DG market than a new program with different rules and incentives. Implementing the RRFP model with the prescribed enhancements could benefit both the utility and developers entering into contracts to defer T&D infrastructure.

## 2.2 RRFP MODEL

### *2.2.1 Definition*

The RRFP will operate as a statewide business model targeted towards radial, hub-spoke and network distribution systems with the greatest deferral values. Achieving these targets will maximize the societal benefits described in Task #1, which accrue not only to utilities but also to the DG market, end use customers and all ratepayers. Amongst the key societal benefits are increased T&D system reliability, lower T&D capital costs and potential reductions in the wholesale market clearing price.

Unlike the prior pilot RFP approach, the RRFP model will be used with greater frequency in NYCA Zone J (Con Edison's service territory), as Zone J has the greatest electric capacity constraints at both the transmission and distribution levels. Nevertheless, the RRFP model would apply to all utility service territories in the state where DG/CHP would be economically and technically feasible. The RRFP model contemplates one or more of following modifications to program design:

- Solicit bids and award contracts using auction or reverse-auction process
- Allow vendors to bid portfolio of standardized Demand Side Management (DSM) and DG measures
- Standardize delivery contracts for DSM and DG measures
- Define delivery terms up front, specify quantities and timing as needed
- Bid out load reduction deliveries as they arise; place orders for low bids
- Expand eligibility to wide range of measures – e.g., DSM, DG, storage, etc.

### *2.2.2 Address Perception of Utility Bias*

The 2006 report also identified a perceived concern that utilities controlled too much of the process. This concern is addressed in the RRFP model in two ways:

1. Establishing stakeholder working group meetings to increase transparency and improve program design. In 2006, an EPRI report prepared as part of the Massachusetts Technology Collaborative, studying the New York Integration of DG Pilot Program, revealed that stakeholder meetings can improve the likelihood for successes with DG projects (EPRI, 2006). The EPRI report also analyzed Southern California Edison's (SCE) stakeholder collaborative approach and found it to provide creative solutions that addressed all stakeholder concerns. The Massachusetts DG Collaborative specifically incorporated a collaborative approach for projects. The collaborative made it possible to:
    a. Identify criteria and screen congested areas
    b. Propose feasible locations
    c. Design methods to evaluate and assure reliability, and
    d. Develop successful contract terms and payment structures.

2. Using an independent third party to process the bids received. Evaluation of proposals by an independent third party further enhances the success of the RFP approach. As described in the 2006 EPRI report, a Technical Evaluation Panel (TEP) consisting of internal utility personnel and external experts would:
    a. Review the potential bids and projects (EPRI, 2006)
    b. Compare the utility cost estimate to the bidder's estimate, and
    c. Collaboratively rank the projects to decide upon the best solution.

Selection process for the TEP would require that there be no special interest on behalf of its members.

In the 2006 Report, one developer bid within 10% of the utility's projected avoided cost. Nevertheless, the utility chose not to work with the developer. The ninth recommendation suggests that utilities should work with developers when the bid is close, rather than automatically rejecting the bid. The TEP and the utility could work with the developer to see if the cost of the bid could be lowered. If the TEP and utility could not reach agreement, each would select their respective best projects and submit to the PSC for a ruling.

There are costs to parties for participation in an RFP process. These costs must be weighed against the expected return, should a bid be successful. Potential bidders will be reluctant to participate if they perceive that meritorious bids have little or no chance of acceptance. Inclusion of an independent third party will provide assurances to developers that their bids will receive fair consideration.

#### *2.2.3 Greater Transparency of the Value of Deferral in Particular Locations*

One approach to the RFP process is for the utility to internally screen a pool of potential projects (sites) and from that pool select one or a few sites to offer in a solicitation for bids. Opportunities may be lost if this process is conducted internal to the utility, without customer input regarding the location of potentially favorable DG projects. For example, a deferrable project may rank just outside the utilities screen for selection yet, unknown to the utility there may be a particularly attractive DG application that would make DG deferral an economic alternative. The bid selection process should be informed to some extent by outside knowledge (external to the utility) regarding feasible DG/CHP development sites that would support the DG alternative. Having greater cost transparency and more complete information on both the utility and the developer side would drive bid prices down, since bidders with better knowledge about the project economics could offer lower cost solutions.

#### *2.2.4 Reduced Transaction Costs*

There are advantages and disadvantages to the RFP process. The exercise of a greater degree of control and the chance to procure resources adequate to meeting the requirement at a lower total cost via an RFP are reasons the approach might be favored. On the other hand, bid preparation costs are associated with an RRFP but not with a standard offer. RFPs are issued on an infrequent basis whereas a standard offer is open as long as the conditions underlying the resource need are met. The bid preparation, review and selection process is likely to be more costly in time and dollar terms than a standard offer approach. Therefore care should be taken to reduce transaction costs in the bid process to the extent possible while still retaining adequate controls and oversight. The process of bid preparation should be streamlined. Forms should be clear and bid requirements plainly described. Online forms requiring exactly what is necessary in an easy to complete format should drive the design. Bidders should have confidence in the timelines that are set, as they must conform their project development and financing schedules to the RFP process.

#### *2.2.5 Enhanced Congruence between Distribution Needs and Optimal DG Sites*

The first recommendation from the 2006 report was to offer the program where DG/CHP was economically and technically feasible. In the initial RFP offering in 2002, each utility was required to issue essentially the same number of RFPs. Still, it's likely that some NY utilities have far better opportunities for cost-saving DG deferral projects than. Utilities with less favorable economics should not be held to the same standard as those with more favorable economics.

The RRFP Model would be implemented by a fixed price specific to a particular location, which would remain constant through the life of the contract. It would be formulated by the utility, as a function of the utility deferral value as approved by the NYSPSC.

The model should include a set of performance conditions designed to address the disincentives that address utilities concerns about the reliability and performance aspects of customer owned resources, and likewise foster a more streamlined, efficient and economically attractive opportunity for DG/CHP developers. These performance conditions may include:

(a) Sizing the project to the location
(b) Certain performance requirements
(c) Potential utility control over the resource
(d) Agreement terms such as the timing commitment for construction completion

(e) Length of term for the payment commitment, and
(f) Requirements for compliance with permitting and regulations.

The development of a price signal begins with a review of the utility distribution capital investment plan to identify areas of constraint and in need of upgrade over the planning horizon, with a screen for DG feasibility as a measure that could defer or eliminate the need for utility T&D capital expenditure.[9] Based on the deferral value of a T&D project identified in the review process, the utility will provide a fixed monetary incentive based upon the deferral value for the life of the contract for installed customer owned DG/CHP resources. The cost of the incentive could be recoverable through a number of ways: through monthly adjustments from the utility's revenue decoupling mechanism, through system benefit type charges, or through rates. Once the DG/CHP capacity has been valued and is installed and deemed operational by the utility, the winning bidder would receive the value of the deferral over the life of the contract.

### *2.2.6 Adequate Contract Terms*

One of the roadblocks identified in the 2006 report was the short duration of the contract period. Utilities would provide contract periods of only three to five years, which represented the deferral period of the distribution system upgrade, but was considered too short a contract period by developers. As a possible solution, The RRFP model could extend the contract length but at a lower value. The lower value would benefit the ratepayers and the utility. It would also benefit the DG developer by guaranteeing a revenue stream over a longer period. Some developers were willing to accept marginal projects provided the contract period was at least 15 years (2006 Report). Developers felt that longer contracts would provide a guaranteed, steady revenue stream to support other projects.

### *2.2.7 Reliability and Redundancy Issues*

Utilities typically prefer to control the operation of DG units that are relied upon for distribution system support rather than engage resources for distribution support that are controlled by the customer. Operational control offers the utility assurance that the resource will be available to meet local requirements. Customers find it costly to provide the redundancy that a utility may demand. If a utility over-enrolls the program by requiring redundancy from every DG customer, it will ultimately result in a lower contract price between the customer and the utility, and render the project not cost-effective (MTC Annual Report, 2005). Reliability and redundancy issues are critical terms of an RRFP. Utilities should investigate lowering requirements where the directives do not lead to an appreciable gain for local area reliability, yet exact a cost to the potential bidder. For example, physical assurance requirements might better relate to hours when the resource will be required, rather than a blanket requirement of 8,760 hours per year. Likewise, the utility should consider a diversity factor to adjust payments for resources that recognize the probabilistic nature of performance of a set of resources serving a site, or a local area of need. The bidder on the other hand is going to have to accept some measure of operational controls, financial penalties or both, that will reduce the performance risk that the utility is ceding by turning over reliability responsibilities to a third party. Ultimately the utility is responsible for the safe and reliable operation of the distribution system and in the absence of direct control the utility will have to set protocols to assure that the outside party meets the proper standards.

### *2.2.8 Penalties and Operational Concerns*

In theory the degree of control could be structured along a continuum ranging from full utility control, to utility control at peak times or emergency contingencies, to customers having full control. DG redundancy and diverse DG resources may help (MTC Annual Report, 2005; Hedman, 2004). Customers who chose to control their units could be subject to a schedule of penalties for non-performance. The penalty could be consistent with the New York Independent System Operator's (NYISO) Real Time Locational Based Marginal Price (LBMP) for that zone plus an

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[9] The screening process should also consider factors related to environmental justice, network reliability, mitigation requirements in terms of timing and size load relief.

additional adder. The Real Time LBMP consists of the marginal cost of energy plus the marginal cost of losses plus the marginal cost of congestion. The penalty could be assessed if the DG/CHP resource was not compliant when requested by the utility. The generation capacity shortfall penalty could be determined by the shortfall in capacity the DG resource provided when called upon to perform during the system peak. Penalties should be set at a level that encourages the correct reliability response from the end user. When set too high, penalties might defer participation in a bid program, but if set too low, may result in reliability costs in the local area served.

#### *2.2.9 Benefits*

There are three main benefits to this updated model. The first benefit, an existing familiarity with the RFP approach, results because the fundamental structure of the RFP model will remain unchanged. Developers, regulators, and utilities are experienced with the essentials of this model. The second benefit, a better integration of the key stakeholders, will allow for a more successful program that could include the following action items:

1. Forming a collaborative in order to provide greater transparency to all stakeholders.
    - Utilities could direct developers to optimal sites in their service territory
    - Utilities could advise their customers about the program, and
    - Developers could discuss with utilities and customers obstacles they are facing during the process, as opposed to after the process is over.
2. Selecting an independent third party to work with the utility. The third party would:
    - Review the bids, providing objective analysis
    - Rank the projects according to predefined value standards, and
    - Select the most appropriate projects.

The third benefit, an integration of other demand side resources into the bid process, would provide greater opportunities for the development of responsive DG bids by project developers. This was not the case under the prior RFP process. Evidence from numerous other studies points to the benefit of a multi-resource approach that aggregates a variety of resources, including measures such as energy efficiency retrofits, and demand response.

#### *2.2.10 Risks*

An RFP process has certain advantages and disadvantages relative to a standard offer, or posted price approach, such as the High Value DG model, described later in this section. The RRFP approach gives the utilities (and regulators) more control over the final outcome. The RFP can be written in a way that provides a very exacting level of detail as to what constitutes an acceptable project. The RFP represents a price discovery method that relies on the developer/end-user to announce its bid to serve a requirement, rather than the utility announcing what it is willing to pay. The utility may get a better bargain, but this could be offset by generally higher transaction costs of developing and administering an RFP process.

#### *2.2.11 The Role of Utility Buy In*

Whether or not the utility embraces the RRFP process is likely to play a pivotal role in its ultimate success. Utilities possess the information on which areas are potentially the best candidates for T&D deferral utilizing customer sited assets. They are in the best position to assess the cost of a traditional utility distribution capital solution. A suggested refinement of the prior RFP was a recommendation to more productively use the existing utility-customer relationship. Utilities are in a strong position to promote each of these models through a range of marketing tools already in place, such as the company website, bill inserts, meetings with potential customers, vendor networks, and so on. Utilities should be required to meet with prospective customers in their service territories where the viability of DG shows promise. Utilities should explain not only the benefits of DG to the system but to the customer as well.

**Obstacles to Utility Buy-In**

1. Physical assurance requirements imposed by utilities
2. Difficulties in matching lead times in planning projects
3. Contractual issues between utilities and customers
4. Control issues (if a RRFP were to be issued, the utility would most likely require central dispatch due to the need to activate the resource at the precise time when needed due to reliability expectations; it is unlikely that the utility would allow the customer to activate the resource) (Armstrong, 2010)
5. Most DG developers do not integrate utility reliability expectations into their bids. As one developer stated at an April 2010 Northeast CHP Initiative meeting, "it only takes 85 percent availability to make a DG project cost effective" (Armstrong, 2010)
6. Customer resistance (it is already a difficult proposition to sell customers on the advantages of DG in today's economic conditions. It may be even more difficult to convince customers to enroll in the RRFP because most businesses are risk averse, especially when the business does not understand all of the issues involved. Thus, if a program were offered, the customer and developer would be driven more by the incentive and the "bottom line" than reliability brought to the system)

Based on evidence from the Project Team's research and outreach, a greater role for distribution utilities is recommended in project development. Most developers who partook in the original RFP process would have welcomed utility intervention for several reasons:

1. Considerable labor and overhead could have been averted in submitting bids if bidders knew the utility provided support for the project. Most customers did not understand the complexity involved with participating in the process.
2. Though some developers did not submit bids, they did incur costs reviewing the solicitation and requirements. These costs could have been allocated to other opportunities.
3. Developers would have preferred a greater reliance on a turn-key approach because of the security and bonding requirements associated with the program (Demaskos, 2009). With more active involvement in the project development phase, bid costs could have been lowered. One developer believes that Con Edison could not provide a turnkey approach today. Since the RFP program ended, this developer believes that obtaining approvals and coordination for CHP plants has become more complicated, because the utility has had too many personnel changes, including staff that is not familiar with CHP regulations, and is slow to respond to requests for information (Cristofaro, 2010).

Con Edison is using energy efficiency and demand reduction as tools for reducing distribution capital costs. Stakeholders perceive that customer-owned DG is not accorded the same value as a potential T&D asset. There are legitimate, yet potentially solvable issues that are precluding adoption of programs that would fundamentally include DG CHP in a suite of measures for reducing distribution system capital costs.

Nevertheless, there are a few recent examples where both the utility and customer have benefitted from a DG project as an alternative to a distribution system upgrade. For example, in 2005, the Aviator Sports and Recreation complex in Brooklyn redeveloped four hangars at Floyd Bennett Field (Armstrong, 2010). This required an upgrade to 4,000 Amp 208 volt service, which would have cost $2-3 million in reconductoring charges by the utility. The project was able to go forward without reconductoring when a CHP system was installed. Though this project was not a result of a RRFP program, it shows that quantifiable financial savings exist and can be realized when the utility, customer, and developer work together.

Table 1 below summarizes the major utility and developer issues regarding user-owned and controlled DG CHP as a distribution system asset:

| Subject Matter | Utility Concerns | Developer/Customer Concerns |
|---|---|---|
| Reliability | 99.9% availability with no fault current onto system. DG can trip from voltage disturbances during storms. | Project economics are satisfactory when the DG resource operates at a minimum of 85% availability. |
| Control | Utilities generally require control. | Developers usually unopposed. Physical assurance an issue for customer. |
| Deferral Value | Would not prefer to provide value for fear of gaming the system. | Would like an idea of value of deferral to gauge whether worthwhile to bid. |
| Other Distributed Resources | Most utilities value EE and demand response, but not DG. | No objections. |
| Contract Term | Utilities prefer short term at value of deferral. Less time equals less contractual commitment. | Developers prefer longer terms for guaranteed revenue streams. |

**Table 1: Utility/Developer DG Concerns**

In the end, a Refined RFP process (RRFP) is just a mechanism for striking a bargain between two parties -- the utility and the host site -- to use a customer-side facility as a distribution system asset. There are legitimate issues on both sides of this potential bargain. Yet, there are likely to be real opportunities for utilities (and ratepayers) to reduce overall system costs by encouraging the development of customer projects that create measurable local distribution benefits. A large fraction of the capital equipment currently operating is quite aged and in need of repair. The investment costs for meeting this need is substantial. As the growth in utility rates becomes ever more driven by capital investment needs, there is going to be significant pressure to find alternatives. Using customer sited DG /CHP resources to meet distribution requirements may be increasingly seen as a desirable mechanism to leverage private investment to meet this ever-growing need.

# 3 High Value Development Zone Model

## 3.1 MODEL OVERVIEW

The High Value Development Zone DG (HVDG) model uses a zonal, location based approach to offer an incentive for the procurement of DG resources. The model is designed to identify the most valuable deferral opportunities in order to direct DG/CHP development to the areas on the distribution system where it is likely to create the greatest system benefits. Presently DG/CHP development takes place absent information about the most desirable siting decisions from the perspective of the utility. Consider two potential projects of equal economic value to the two end users operating on a distribution utility system. If location at one site is on a severely constrained network it likely has far greater value to the utility and the ratepayers than does an identical project in an area with plenty of excess distribution system capacity.

This model uses a price signal that in theory spurs deployment of DG towards distribution-constrained areas of the network, where the value in deferring a traditional distribution system upgrade is high and the value to ratepayers greater. The intent is to encourage, to the extent possible, the installation of customer owned DG/CHP that complements utility operations. The model seeks to share achievable benefits between DG developers, utility shareholders and ratepayers at large, providing a win-win solution, such that the needs, interests and profitability of all parties could be synchronized to the benefit of all.

The HVDG model uses a pay for performance incentive mechanism, where the distribution utility offers 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 provides a mechanism for 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. There is an option for a minimum threshold capacity to address situations where only partial satisfaction of the constraint has no demonstrable value for the utility.

The utility's highest priority is reliability of service, whereas the end-user's concern is the optimum economic operation at the facility. When the asset is outside the direct control of the utility there is a risk that the site owner's operational decisions are not in synch with the utility reliability requirement. In order to foster more congruence between the utility and the DG/CHP developer, the HVDG model provides utilities with certain means for exercising operational control, or operational influence (through the incentive and penalty approach) over the DG/CHP resource.

**Key Elements of the HVDG Model:**

- Publicly announced standard offer price, differentiated by distribution zones
- Pay for performance incentive/penalty for under-performance
- Simpler administration
- Utility provided with operational influence or control over the resource

### *3.1.1 Zone Definition*

This HVDG model is perhaps most appropriate for New York City, or NYISO Zone J, where the highest wholesale energy and capacity costs, and the greatest rate of peak load growth occurs in the state, however it could also be applied in other territories (PSC Case 09-E-0115, 2009). The New York Control Area (NYCA), which includes all of New York State divided into NYISO's Load Control Zones, is subject to Resource Adequacy Guidelines established by the Northeast Power Coordinating Council. Because most of the reliability risk in the state occurs in NYISO Zone J, the guidelines specifically require that 80% of New York City's peak-load capacity be generated at facilities within the zone. To do so, Zone J relies on numerous peaking generation units, some of which operate inefficiently and produce high emissions. Con Edison, the distribution utility that serves Zones H, I and J, operates a massive distribution system, with 94,000 miles of cable, 2,204 primary feeders and 61 area substations, serving over three million customers (Con Edison website).

In 2009, costs for upgrading the distribution system in Zone J were quantified by the NYSPSC (PSC, Case No. 08-E-1003, 2009). NYSPSC staff used figures from recent Con Edison projects to estimate that the value of marginal avoided distribution costs for the utility ranged broadly anywhere from as little as $22 per kW-year up to $609 per kW-year. Though the Team knows the minimum and maximum marginal avoided costs, the shape of the distribution of costs was not made public. Needless to say, for utilities where upgrade costs are in general more expensive (where there is a concentration of costs in the upper portion of the distribution curve), there are greater opportunities for finding mutually beneficial DG/CHP deferral opportunities.

Under the HVDG model, Con Edison would identify a set of areas where the most attractive deferral value opportunities lie, and publicly post individually designed incentives for each of those locations to invite customer-side deferral projects. The incentive would be priced as a function of the deferral value in each location and available to DG/CHP/DER resources that singly or in aggregate are sized appropriately to achieve deferral. To receive the incentive, the performance of the participating DG/CHP facility would have to satisfy certain contractual obligations that would provide assurance and reliability to the utility, as described below.

### *3.1.2 Pricing Strategy*

The HVDG Model would be implemented by a publicly posted payment specific to a particular location, formulated by the utility, and set as a function of the utility deferral value. The development of a price signal begins with a review of the utility distribution capital investment plan to identify areas of constraint and in need of upgrade over the planning horizon, with a screen for DG feasibility as a measure that could defer or eliminate the need for utility capital expenditure. The screening process should also consider factors related to environmental justice, network reliability, mitigation requirements in terms of timing and size load relief requirements, and whether there are existing targeted demand or supply side resource acquisition activities capable of reducing peak demands at the area of constraint.[10]

[10] Con Edison recently proposed a model for zonal price signals for solar development entitled "Transforming the Solar Marketplace: A Proposed Con Edison-NYSERDA Solar Program," Comments of Con Edison and Orange and Rockland Utilities, in PSC Case 03-E-0166.

### 3.1.3 Program Mechanics

- *Setting the Payment*: The incentive can be offered as a monthly or quarterly payment as a dollar amount per kW/year that is calculated relative to the deferral value in the posted location. The duration of the payments is relative to the length of time that a DG resource is expected to defer a traditional upgrade. For example, if a location is identified by Con Edison to be in need of 3000 kW of certain DG resources in order to defer a certain distribution upgrade for a period of five years, then a price for performance based on a kW/year would be announced in that spot, to last for five years.

- *Performance Conditions*: The HVDG model requires a set of performance conditions designed to address the disincentives that drive utilities away from customer owned resources, and likewise foster a more streamlined, efficient and economically attractive opportunity for DG/CHP developers. These performance conditions include setting the appropriate size of project specific to the location, performance requirements, control over the resource, and other agreement terms such as the timing commitment for construction completion, length of term for the payment commitment, and requirements for compliance with permitting and regulations.

- *Location*: The highest cost locations (e.g. at the top ten or twenty percent of the deferral value range) on the distribution system that are targeted for medium to longer-term upgrades in the distribution capital investment plan form the initial pool. These may include upgrades required for forecast load growth or for reliability constraints. Once those locations are identified, they must be confirmed further to be feasible for DG/CHP.

- *Resource Size*: For a DG/CHP resource to participate in the incentive, it must be sized appropriately for the need in each particular location, individually or in the aggregate. The spot incentive particular to a location could be designed to be a step function (all or nothing) or smooth (incremental) depending on the nature of the value created by deferral. For example, if anything from 0 kW to 1,000 kW creates no measurable value relative to the need, whereas at 1,000 kW the need is fully satisfied, the preferred approach would be a step function of all-or-nothing. (Alternatively, all awards for that location could be conditional on receipt of a total of 1000 kW of qualified proposals.) In such a location Con Edison would announce that they will pay full price for a minimum resource of 1,000 kW, and after 1,000 kW the need will be satisfied and the value of the payment will be $0. In the alternative, if the need is partially satisfied when 500 kW of DG resource is available then partial payment will be made at that point, and perhaps another payment when the combined DG resources are at 750 kW, and again at 1,000 kW.

- *Resource Control*: In order to accept a DG/CHP resource as an alternative to a distribution system upgrade, the utility will desire influence over the operational control of the customer owned DG/CHP resource, for reliability purposes. This can be accomplished either through indirect means by certain terms and conditions of operation for payment to be received, or by direct physical control over the resource (e.g. automatic controls). The indirect approach to influencing the operation of the resource will not enable the utility to fully determine the operating schedule of a DG resource under ownership and control of a third party, but it can use an incentive and penalty scheme that influences the operational choices of the DG owner/operator. For example, a DG resource may be uneconomic for the site to run at a time when the utility requires its operation to meet a local peak need. Program terms must ensure that the DG/CHP resource is available, at a minimum, to meet the utility's requirement and not operating on a schedule that only optimizes the site's economic return. An indirect method of control would condition payments on performance and set penalties for non-performance at stipulated times. With a direct control approach, under appropriate circumstances and upon mutual agreement, the utility would be provided with physical control over the resource, to guarantee that the resource would operate during peak periods.

- *Program Flexibility*: The model can be designed to allow adjustments to the incentive prices that correlate market conditions and deferral values; however it is desirable from the DG/CHP owners' perspective to have fixed prices and time periods over which the payment will remain constant. The associated uncertainty of adjustable pricing creates a level of risk to the developer. Such uncertainty has proved problematic in other settings. For example, sites have a difficult time monetizing the present value of a stream of payments from Renewable Energy Credits (RECs), because the future value of RECs is highly uncertain. With perfect information a site could capitalize the future value of a known and certain stream of future payments. If adjustments to the incentive are permitted, they would be made at the discretion of the utility based upon a pre-determined protocol that sets forth the conditions. Should the model be implemented with price flexibility, the utility commission should be engaged in weighing the concerns of both parties and the risk before allowing such adjustments.

- *Equipment Lead Time and DG Ramp-Up Rates*: Typical equipment and construction lead time for distribution upgrades can range from six months to two years for feeders, two and five years for substations and between three and eight years for transmission upgrades (Salamone, 2007). Lead times impose a hard constraint on the DG/CHP resources. It is imperative that the resources be available, in sufficient quantity, when needed. The program must anticipate realistic DG ramp-up rates. In interviews with utility staff, the Team was told that they would have to begin planning an alternative option, if an adequate sized DG resource was not ready by a certain cut-off date (well in advance of the need date). Risk from delays can be captured by setting a higher discount factor, or by a write down of the DG deferral value as costs are incurred to plan for an alternate wires solution. The posted incentive for each location will need to be formulated with consideration of the appropriate timing to construct and begin operation of the DG resource.

- *Unforeseen Contingencies*: Similar to the issue above, there is a significant risk of delay from any number of unforeseen factors, such as siting, permitting, regulatory compliance, or previously secured commitments failing to go forward. When opting for a DG alternative, if the utility also plans for a wires upgrade as a backstop, the cost associated with such a plan lowers the deferral value that can be credited to the DG project.

## 3.2 ISSUES

Previous attempts at utility facilitated, customer owned DG development have demonstrated little success, in large part because the over-riding concern expressed by the utility is distribution system reliability while the interests of DG hosts sites are quite heterogeneous. At some level of utility payment the incongruence of interests could be bridged, with the DG host site accepting the utility's pre-conditions in return for financial compensation. If that level of payment can be made at a net gain to the ratepayers, at the same time that reliability standards are maintained then a mutually beneficial end has been reached.

Privately developed DG is sited based on the suitability for the host customer, without consideration of potential distribution upgrade deferral benefits for ratepayers and society as a whole. DG operating at sufficient scale, at periods coincident with the local system in congested areas does provide, and uncompensated benefit. If sites were paid for this value, the economic return at such locations would be enhanced, resulting in more DG projects being constructed. Since these hosts are not compensated when they do produce this broad based benefit, the investment in end-user DG/CHP resources in congested areas will be under-provided from society's perspective. Sites where DG has a significant congestion mitigation value has a greater social return than a similar project at a site with no congestion relief value. Capital expenditures for distribution system upgrades can represent a considerable share of a utilities cost of service. Therefore, if more cost effective means of satisfying local congestion can be found, all ratepayers benefit.

The following section includes discussion on the following key issues: the complications and difficulty in measuring deferral values and the asymmetry of deferral value information; grid reliability issues; management complexity; administrative and transactional costs; and the impact on markets.

### 3.2.1 Measuring and Disseminating the Deferral Value

As discussed above, DG can provide an opportunity for considerable cost avoidance when used as a substitute for distribution system investments, particularly in locations where the marginal avoided capital investment cost is high. Whether employing the Utility Owned model, an RRFP model or a posted price (HVDG) approach, the initial step is identification of areas of the distribution system in need of upgrade that are suitable for utilizing DG as a close or perfect substitute for distribution capital investment. This is the technical feasibility assessment stage.

> *For a utility whose capital spending is centered around antiquated infrastructure rather than anticipated load growth, the set of viable DG solutions is markedly diminished. National Grid reports that of the total capital spent on investments, only 20% or so is load growth related, while the other 80% replaces old equipment or funds upgrades required from contingency events (Roughan interview, 2010).*

The next stage is ascertaining the economic viability of the DG/CHP solution. The information required to accurately measure the value of the distribution deferral potential is in the sole possession of the distribution utility. Under the utility ownership model the company can conduct its economic analysis internally and judge its economic viability.

With the customer owned models the situation is far more complex. Developers have no access to information identifying areas of high marginal distribution cost. More importantly, they have no economic incentive to choose those locations over any other feasible locations to site a project.

Access to deferral value information can assist developers in evaluating their bids in an RFP process and the information conveyed by posted prices for areas requiring upgrades directs development to the highest cost areas in a standard offer process. The 2006 Pace/Synapse Report identified the lack of deferral value information as a major stumbling block for developers. In the 2006 Report, one developer commented that if the utilities needs were more transparent, it would have saved both the utility and the developer time and money. By understanding the needs of the utility, a developer can concentrate on those projects for which it could provide a competitive solution. Competition is enhanced when all market participants have access to the same information as multiple parties vie to provide a least cost solution in an RFP type process.

The HVDG Model addresses information asymmetry by allowing the distribution utilities to post a price they are willing to pay for an incentive to develop DG in a location that best suits their current load forecast and associated system constraint needs. The posted price need not directly reveal the underlying deferral value itself. Because the posted incentive is only a function of the underlying deferral value, the utilities can maintain their desired confidentiality over proprietary information, if the Commission finds that warranted. The function of the posted price is to provide savings to the utility (and ultimately to the ratepayers and society) from using a DG resource as a distribution upgrade alternative.

According to NYSPSC staff, in recent proceedings staff has accepted some confidential Con Edison deferral values that were significantly higher than the standard Long Range Avoided Costs (LRAC) for Location Based Marginal Prices (LBMP) in the top 60 hours/yr, and for shaving peak on constrained distribution networks (Tress, 2010). The information on the locations and times of high marginal distribution costs are typically compiled as part of the distribution resource planning process. The deferral values should be measured by NYSPSC approved avoided cost methodology, as a component of Total Resource Cost methodology (as described in the NYSPSC Energy Efficiency Portfolio Standard (EEPS) Case) or by some other NYSPSC approved approach.

**Con Edison service territory as a test case**

There are many aspects of the current operating environment in the Con Edison service territory that make it an attractive test case for systematically and formally incorporating DG into the distribution planning process.

According to Company testimony, of the $854 million Con Edison sought in the 2008 rate case, the largest single driver is "infrastructure investment," which accounts for $170 million or about one-fifth of the request (Rasmussen Direct Testimony, p. 11). Given the role of T&D infrastructure investment in driving up Con Edison's cost of service, it is prudent to explore systematic and formal mechanisms by which Con Edison could analyze using additional investment in DG, whether utility-owned or customer-owned, as a means of avoiding or delaying investment in T&D infrastructure.

Con Edison has experience using demand side resources to defer capital investment. In testimony before the Infrastructure Investment Panel for the recent Con Edison rate case, Con Edison stated that in its 2008—2017 Forecast it is planning for demand side resources to defer eight new substations and the installation of four feeders, resulting in deferral of $1.2 billion of capital investment. Con Edison's Ten year Independent Load Forecast of March 2009 defers two more substations (Westside and Hudson Yards) beyond the current 2009—2013 capital plan, resulting in $260 million of additional deferral for 2010-2012.

Con Edison uses an annual internal budget planning cycle, which starts in draft form April and is adjusted after the summer events to result in a formal internal budget by the end of the calendar year. Con Edison also develops a five year plan each year as an extension of the one year plan. The five year plan deals with longer term projects, such as substations that have a lead time of two to three years.

Con Edison develops capital plans that are consistent with their internal budgeting, and submits those plans to the NYSPSC for audit. Budgeting for investments involves a system load analysis, with both top down and bottom up approaches to loads to determine where the system needs reinforcement. These are 10-year resource plans and are submitted to the NYSPSC, which audits the 10 year plan for consistency with the company capital plans. These plans are not routinely made public. The most recent three-year plan is a comprehensive Joint Settlement of the most recent rate case.

### *3.2.2 Grid Reliability and the Capital Planning & Acquisition Process*

The current NYSPSC reliability standard has been in effect since October 12, 2004, as described in Cases Nos. 02-E-1240 and 02-E-0701. The standard sets forth the following four reliability objectives:

1. Each utility must improve its reliability cost effectively and continue to do so over time.
2. Each utility must analyze at least five percent of its circuits each year and develop and maintain a program to correct its least reliable circuits.
3. When feasible, each utility must make every attempt to minimize service interruptions when working on its lines and/or equipment.
4. Each utility's System Average Interruption Frequency Index must be calculated each year.

Planning for T&D upgrades in New York City is a particularly challenging prospect. The dense urban environment typically presents strong opposition to new peaking generating facilities within Zone J. Health concerns about EMF from high tension lines sends new transmission lines underground, which in turn drives up distribution system upgrade costs. DG can provide numerous benefits that offer solutions to these challenges, including the potential to strengthen grid reliability by mitigating load pocket constraint. In a 2001 report, Keyspan Energy recognized DG "as a valued component in a customer-oriented strategy to manage local electric load growth, and a good platform for growth in a deregulated market" (Berry, 2001). EPRI reports that while specific distribution upgrade deferrals can be supplied with certain customer owned applications, there is likely to be enhanced and systemic grid reliability improvements from the diversity supplied by integrating multiple DG/CHP resources into the resource planning process (EPRI, 2005).

#### *3.2.3 DG for Distribution Capital Deferral: The Impact of Reliability Concerns*

As noted on several occasions in this report, there is a large literature indicating the DG and other distributed energy resource (DER) assets such as demand response and energy efficiency can be used as to defer or perhaps avoid utility distribution capital investment. The actual record of employing DG/DER for that purpose is quite limited. The 2006 Pace/Synapse report concluded that certain utilities appeared to deny projects because the DG project's reliability standard could not match the same reliability of the utility's whole distribution system. National Grid (formerly known as NIMO) rejected one project because it could only provide 98% reliability compared to 99.9% off the utility's feeder (Leuthauser, 2004). The 2006 Report recommended that utilities should not measure the value of DG in isolation, but instead integrate its value into the whole system.

In the most recent rate case, Con Edison advised it "would consider supporting new incentives for encouraging reliable and timely facilitation of clean DG interconnections" (NYSPSC Case No. 09-E-0428, 2009). Still, to date, Con Edison has not selected any third-party DG providers to participate in its Targeted DSM Program. One major reason for this result is that the parameters of the TDSM program appear too restrictive, which was confirmed by Navigant Consulting independent review of Con Edison's program. An independent study of the targeted DSM program, performed under PSC Order, was completed by Navigant Consulting and filed with the PSC on May 8, 2009. Navigant concluded that DG is not used due to Con Edison's requirement of physical assurance. Navigant expressed in its report that "[p]physical assurance involves use of communication and control systems that would interrupt customer load in amounts equal to contracted firm DG delivery if the generator was unavailable when needed to reduce load" which is claimed to be necessary "to assure certainty of load reduction at the time of the load area peak" (Navigant, 2009).

> *In order to more commonly employ DG as a means for deferring distribution capital investment, a consensus must be reached on reliability issues. For example, parties must reconcile concerns about DG sites providing 100% physical assurance. The distribution utilities should employ standards that measure reliability in a consistent manner whether applied to their own existing resources or new DG/CHP.*

In 2009, testifying in NYSPSC Case No. 09-E-0428, Paul Chernick of Resource Insight described how Con Edison's physical assurance requirements reveal a double standard. He testified that three of Con Edison's gas turbine generators ranging from 12 to 20 MW each — one located on W. 59th St and two located on W. 74th St, built over forty years ago—were treated as load relief resources for nearby substations and feeders despite the fact that those generators are larger in scale than most customer owned DG, which carries with it a greater reliability risk than most customer owned DG (Chernick, 2009, discussed in detail in Task 1 report). Chernick further stated that if these same generators were proposed for Con Edison's targeted program, they would be deemed ineligible to participate according to Con Edison's program requirements.

The utility argument is that reliance on a non-wires solution to defer a T&D upgrade will require total confidence in the reliability of the resource, suggesting that the DG alternative must operate at 99.9% availability. Many DG projects operate at 95% to 97% availability. What the utility really requires is a guarantee of availability at the time of resource need. If there are multiple DG resources available to supply the need at the constrained location, then the unit availability is not the right measure—the availability of the fleet of operating DG/DER assets is the correct metric.

For the CHP developer, optimal economic performance occurs with base-loaded generation and high thermal utilization; however, the utility has no interest in thermal dispatch. This does not necessarily represent conflicting interests. In fact, if the CHP site is designed to run as often as possible, then the customer's objective function (run all the time) and the utility's primary interest (be running on and near local system peaks) are entirely in synch. While many CHP projects will fare best when operating base-load, this is not the only economically viable mode of operation. There is a significant set of potentially viable CHP projects that have negligible thermal and electric requirements for large numbers of hours of the year. Such projects may be successful if they run intensively during the highest cost (peak) hours and are able to fully use the thermal energy generated at the same time. As long as there is a high correlation between the economically advantageous times for the site to be running its generators and the occurrence of the local distribution area peak, there is no divergence of interests. It would only be the case that utility and CHP interests diverged if the days and hours when the utility needed the generator running, were days and times that were un-economical for onsite generation.

The reliability of DG operation can be affected by voltage disturbances or downed circuits from storms, accidents, or other contingency events. The operational mechanisms to control these situations are much more difficult, often occurring with no predictability. In contingency events, the utility is concerned about the impact on the grid if the unit goes down when the loads on the system are at peak demand. Such a contingency could occur with little or no notice. This issue could be resolved with some sort of automated control, such as a recloser or fuse between the utility and the customer.

Utilities may oppose DG as a means of deferring distribution upgrades based on the following claims that relate to adequate reliability, lead time, incongruence of interests and other contractual issues. These claims can be addressed as described in the text box below.

**Utility opposition issues**

**Reliability**
The utility may claim that reliability is compromised if the DG resource fails to produce the desired output, and the customer requires power to continue operations.

**Diversity**
Multiple DG/DER assets serving the local requirement have a reduced joint probability of failure. If a single DG resource is providing the necessary reserve, then the reliability on that network is a function of the reliability of that asset. The rebuttal to this concern is that multiple DG/DER serving the local requirement have a miniscule joint probability of failure (i.e. that all resources fail simultaneously). This is especially true if the assets satisfying the need are configured so that no one resource accounts for an overwhelming share of the requirement.

**Lead Time**
Most utilities need 12 to 18 months lead times to plan and implement traditional solutions to capacity constrained areas and claim that relying on its customers to meet its requirements would leave the grid in jeopardy. Most developers who were interviewed also require this amount of time due to delays with customers and securing adequate financing for the project.

**Incongruence of Interests**
The customer's primary objective is cost minimization, and the utility's primary objective is to meet the reliability needs of local distribution. Analysis can empirically determine whether the two objectives are in conflict, they may not be.

**Contractual Issues**
The utility is concerned with the assumption of contractual obligations by any future owners of the DG resource for the entire term of the contract. Appropriate contract terms regarding assumption could be negotiated with third party design/build owner/operators. Host sites can be prioritized on the basis of this type of risk.

**Standby Service**
Utilities suggest that virtually all customers with installed DG also require standby service, meaning that the utility would still have to plan on meeting its systems need in the event that the DG was not operational.

**Sizing Constraints**
In Con Edison's proposed M29 Transmission Line Project in 2006 to the NYSPSC, they advised that typical DG projects ranged from two to 10 MW which would mean several DG projects would need to be installed in order to defer this project. Con Edison references Pace's 2002 *Combined Heat and Power Market Potential for New York State* (Pace, 2002 Report) which said even though there were 26,000 sites in New York that have the technical potential for CHP representing 8,500 MW, close to 74 percent of these sites were from plants that would produce less than 5 MW.

#### *3.2.4 Reliability Solutions*

The customer-owned business models are tailored to address the needs of utilities and developers. The models provide reliability assurances for utilities and incentives to offer the assurance to the DG developer. These approaches may involve technical measures to provide operational control or commitment, as well as policy mechanisms that elicit specific behavioral responses.

Even if physical assurance is needed to maintain reliability, the degree to which it has been required is onerous to the DG developer (Yap, 2004). Accordingly, Con Edison is contemplating reducing its physical assurance requirement to peak load hours for the distribution system (Gazze, personal communication).

An alternate means to ensure reliability that may be more effective than requiring physical assurance would be to assess penalties for non-performance. Penalties for not meeting the reserve requirements can also incent behavior. For example, participation for current ISO market participants would require fulfillment of a required schedule or payment of a penalty for the cost of replacement. Customers who install DG provide a resource, however if the unit is not available, customers could be assessed a penalty, for example, equal to real-time LBMP plus an additional incremental monetary penalty assigned and determined by the utility. Since DG (especially CHP) has proven to be a reliable resource, participating CHP customers would be exposed to minimal risk.

DG developers have also suggested the use of internal controls up to the thermal load point (for CHP); and an external centralized override that increases the electrical output above thermal loading, with the use of thermal dumping when necessary (Armstrong, 2010). A suggested incentive would compensate the resource for dispatch above thermal load, where there is a positive "spark spread."[11] If a positive spark spread does not exist, it needs to be induced.

Reliability can also be enhanced by diversifying the DG resources deployed in a particular location. According to a study performed by Energy & Environmental Analysis (EEA), when a group of DG units operate as a system, reliability is increased. As was noted in the study, if one DG unit, independent of others, has a reliability risk of, say, 3%, when two such units are used, the overall reliability risk drops to 0.1 percent (Hedman, 2004). By creating local redundancy and diversity with a combination of DG and other demand side resources, utilities can relax their assurance and load shedding requirements during contingency events. As suggested by the 2006 Report, using DG in combination with other distributed energy resources may be mutually beneficial to the utility and bidders including Southern California Edison, the Bonneville Power Administration Non Wires Solution and the ISO-NE RFP. The SCE model relied exclusively on DG. By allowing participation in demand response programs, utilities may be more amenable to using customer-owned DG as a T&D resource. In addition, this may also provide a lower cost solution than just DG alone. The ISO-NE RFP obtained over 250 MW of demand side resources including 100 MW of demand response located in the Southwest Connecticut region (Carver, 2010).

In Con Edison's service territory, fault current issues have also limited the amount of synchronous generation that can be added to the grid in various load-constrained areas. Con Edison contends that the fault current interferes with protection systems and creates power quality issues such as harmonic distortion and voltage flicker (Jolly, 2010). These issues have resulted in a range of proposed technical solutions. For example, Washington D.C.-based Pareto Energy has developed the so-called "GridLink" technology to address this problem. When installed at the customer's site, GridLink interconnects power from multiple sources and switches power from AC to DC using converters, and then switches it back to AC in order to enhance power quality. GridLink varies the amount of power supplied by sources, down to zero, within milliseconds. The grid views GridLink as an on-site generator reducing its load rather than as a power source.

#### *3.2.5 Regulatory Compliance and Complementary Policies*

The HVDG model puts the burden of satisfying regulatory requirements on the DG resource owner.[12] In New York, the approvals and permitting necessary to develop DG/CHP resources are administered by the New York State Department of Environmental Conservation (NYSDEC) Air Pollution Control Permitting Program.[13] In New York City, additional regulations further impact the development of DG resources.[14] Depending on the DG/CHP resource

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[11] Spark spread can be defined as the cost of buying electric power from the grid relative to the cost of natural gas.

[12] Pace published a comprehensive guide for prospective DG/CHP project developers, owners, and planning/code officials that explains all applicable regulations governing smaller-scale (from .1 MW to 10 MW) on-site generation projects (Bourgeois, 2003).

[13] Authorized under the New York State Environmental Conservation Law, Articles 19 (Air Pollution Control) and 70 (Uniform Procedures), and DEC amended regulations 6NYCRR Parts 200, 201, 621 and 231. Available at http://www.dec.ny.gov/permits/6069.html

[14] New York City regulates air permits, boiler registrations, fuel gas supply, piping, venting and stack height, and material & equipment under a number of city codes including the building, electrical and fire codes, involving the New York City Department of Environmental Protection, the New York City Department of Buildings and the Fire Department.

technology,[15] a project must receive one of three types of state air permits, which are based primarily on a comparison of the facility's potential to emit (PTE) using federally-defined major source thresholds. The entire downstate region (encompassing Zone J) is within New York's Severe Non-Attainment Area, which could subject some projects to New Source Review.[16]

In early 2005, the NYSPSC initiated a proceeding to consider Demand Response Initiatives (NYSPSC Case No. 09-E-0115, 2009). As part of the DR proceeding, working groups are actively considering how to reduce the operation of combustion generating units in environmental justice and Severe Non-Attainment Areas. The outcome of these proceedings will have implications for the development of DG resources in those locations.

Both local and state policymakers have recognized the importance and potential of DG. For instance, in PlaNYC, Mayor Bloomberg has set aside a goal to install 800 MW of clean DG by 2030 (PlaNYC, Energy Initiative 9, 2009). The 2009 New York State Energy Plan recognizes that DG/CHP increase energy efficiency, reduces costs and improves reliability.

The DG interconnection process has been a major obstacle to DG development. In 2000, a NREL study showed that only seven of sixty-five DG projects were interconnected in a timely manner (NREL, 2008). The remaining projects were delayed due to three types of barriers: technical, business practice and regulatory. Some of the technical barriers included power quality issues, safety and reliability. Business practice barriers included contractual and operational requirements. Finally, regulatory barriers included standby tariff issues, ISO requirements and exit fees. This led to the development of IEEE 1547 in 2005, which sought to provide a national interconnection policy (LBNL, 2008). According to the Database of State Incentives for Renewables and Efficiency, there are presently 40 states in the U.S. that have interconnection standards, and in February of 2009, New York standardized the processes for all applications that run parallel to the grid up to 2 MW.

Though the IEEE has made substantial progress in standardizing interconnection policy in its Standard 1547, subtle nuances do exist across the country. Interconnection policy should be streamlined across the country to provide clarity and consistency for project developers who may want to do business in other states. Presently, projects require external disconnect switches and size limits are capped at 2 MW. Increasing the cap up to 20 MW would provide additional incentive for large businesses to invest in DG technologies (Network for New Energy Choices, 2009). Another approach would be to standardize and streamline the interconnection process, which would lower costs and provide certainty for project developers. Costs vary depending upon whether the system will be connected to transmission or distribution system and these costs would be the responsibility of the customer.

#### *3.2.6 Impacts on Markets*

Customers consider several factors when they decide to install DG/CHP. These factors include energy and economic savings, enhanced power quality/reliability, reduced emissions and hedging against price volatility. The success of customer owned models will depend on the effective marketing of the model to those who recommend, bid, develop and own/operate DG/CHP systems. The incentive will be ineffective unless it contributes meaningfully to a project's economic fundamentals (IRR or payback).[17] To the extent possible, incentive levels should mirror the deferral value of an investment.

On the other hand, customer owned DG models will in general give more competitive impetus to developing the market for DG service providers (turnkey operators, installers, engineers, maintenance companies, etc.) because private companies participating in DG projects are facing fierce competition and are making every effort to find and

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[15] Technologies governed by the permitting process in New York include natural gas reciprocating engines, diesel reciprocating engines, micro-turbines, combustion turbines, fuel cells and renewables.

[16] The New Source Review permitting program was originally promulgated under the 1977 Amendments to the Clean Air Act. Nonattainment NSR permits are required for new major sources or major sources making a major modification in an area not in attainment with the National Ambient Air Quality Standards (NAAQS). In New York State, the NYSDEC administers NSR permits for all of New York, except for PM2.5 non attainment, which is administered by US EPA, Region 2.

[17] Although payback periods are considered to be an inferior measure of economic return, many businesses report using the metric and in some cases a "years to payback threshold" may be set as a screening out mechanism for any projects that do not fall within the period.

offer cost-effective DG/CHP solutions for their customers in all aspects of DG development and operation including engineering, designing, procuring equipment and fuel for, building and maintaining and operating DG projects on their own or using other private companies.

For example, Fran Cummings, Policy Director for the Renewable Energy Trust, Massachusetts Technology Collaborative (MTC) noted with regard to the lessons learned from MTC customer sited DG pilot projects that the programs would also benefit from collaboration with an energy services company that provides services related to DR since these third party service companies are frequently very effective at finding demand side opportunities and marketing (See the MTC case study section below). Further, one participant in SCE's 500 MW PV program proceeding (discussed in the utility DG model section) mentioned that "competitive markets drive developers to seek new technologies, to negotiate better prices, to find highest value sites, and/or to accept lower return to gain market shares" (CPUC, 2009, page 25).

Still, the utility owned DG model can also use competitive market forces to some extent. As noted in the utility owned DG model section, to the extent these services are contracted out to private companies, the utility owned DG model can also be competitive to their parties. Lastly note that the competitive advantage does not necessarily apply to upstream markets that provide DG equipment because utilities will also purchase equipment from private companies. Upstream markets are likely to be more sensitive to scale than to the whether the buyers are utilities or competitive DG service providers.

#### *3.2.7 Management Complexity, Administrative, Transactional Costs*

The HVDG Development Zone program would be managed by local distribution companies, which would publicly post and adjust spot incentives, administer the application and eligibility review process, oversee performance conditional payments, disburse payments, and submit costs to the PSC for adjustment through the appropriate mechanism.

On the other hand, the operational burden of individual DG/CHP resources, including regulatory compliance, construction oversight, and so forth, fall to the DG/CHP resource owner. In the event utilities retained some form of control over DG operations, they would assume any associated operational burdens under the HVDG model.

Compared to an RFP model, the HVDG model is designed to keep program costs low, for both applicants and utilities. The HVDG model is conceptualized around least cost solutions, by synchronizing the needs of developers and the utility in a way that allows both to achieve cost savings. A simple proposal process allows for low application and proposal costs to the resource owner, and a first come first served review process with pre-established standard conditions simplifies and reduces costs to the utility to administer the selection process. The development of a standard form agreement between Con Edison and DG/CHP developers will lower legal costs.

The management of the RRFP Model would be the responsibility of the utilities and the Technical Evaluation Panel TEP. Management includes setting the incentive; marketing the program, administering the application and eligibility review process; oversight of the DG resource performance conditional to payment, administering payments, and submitting all costs to the PSC for decoupling mechanism approval.

The eighth recommendation from the 2006 Report suggests that utilities should be more involved in the process including marketing of an RFP approach. At a minimum the report stated, the utility should notify large customers about the potential benefits of the program and provide these customers with contact information of potential DG developers.

Once a customer has been selected, the onus would be on the customer to follow through with the necessary permits to install the system. If the customer chose the full ownership model, it would have to sign a contract with the utility that in the event of an emergency and load was not curtailed, that it would be responsible for penalties. The penalty provision would be made part of the participating customer's tariff with the utility. If the customer allowed the utility to operate the system during peak times, it would not be subject to the penalty provision.

Administrative costs can be seen from the perspective of the utility or alternatively from the perspective of the DG developer and host. With traditional wires approaches, utility administrative costs can vary quite considerably. The

Massachusetts DG Collaborative revealed that utilities claimed that administration accounted for 20% of the carrying charge for implementing a DG program (MTC minutes, 2005). The administrative costs for utilities include the planning and permitting process and the time and resources spent in creating and executing the RFP process. In Massachusetts DG Collaborative, key stakeholders questioned the 20% administration charge asserting by the utilities, and instead suggested that administrative costs would likely decrease once the program has been implemented and standardized. Two alternative approaches were proposed, one that would limit administrative charges for projects under a certain size, and another that would assess a fixed fee based on the number of employees needed to run the utility program. The RRFP collaborative group could consider administrative costs in a similar way to MTC, by determining the most effective strategies for administration and lowering transaction costs.

DG developers have their own set of administrative and transaction costs to consider in responding to an RFP. DG developers require adequate time to prepare their bids and find financing for the project and time to implement the project. Transaction costs for developers are increased when utilities do not provide ample time for developers to secure a customer site for the program. Extending the time required for the project could allow for developers to seek lower cost bids from subcontractors for engineering services. As a result, the RRFP model may be more effective if utilities promptly identified reliability concerns associated with proposed locations. In addition, utilities could provide developers with adequate notice of the location of congested areas so that developers could plan in advance to respond to the RRFP by identifying appropriate host customers and incrementally scoping a project.[18] The same issue is also applicable to the HVDG model, but to a lesser degree.

#### *3.2.8 Financing Costs*

Financing costs are heavily influenced by risk. Lenders are wary of a variety of issues, such as risk of default and complicated and varied contract forms. With a streamlined or standard form contract, lender risk premiums will go down, and financing costs will be reduced. Longer lead times would also allow developers to secure more attractive financing, which could enhance the economic benefits for all the parties involved. The lack of transparency for the deferral value forced developers to estimate approximate values for the project; greater transparency would have lowered the costs involved because competitors would have bid costs to secure the contract. This knowledge also would lessen the financing costs for the utilities, because not all bidders would have bid on these projects had they known how the utility valued the asset.

Developers have argued that if the utilities knew the value of the project then they should be provided the same information. The NYSPSC, however, agreed with the utilities stating that developers would be able to game the system by submitting bids at or just below the utility's cost (Rieder, 2005). Some utilities did provide additional information about the project that should have allowed the developer to estimate the value of the project within +/-10% (Hamilton, 2005).

[18] If, for example, the utility provided two years' notice that an award would be issued in a particular location, developers who could guarantee a project to be online within a shorter time period may be eligible to receive an incremental incentive. The detailed design of an incremental incentive could be left up to the collaborative discussion process, or the TEP and utilities.

# 4 DISCUSSION

In this task report the Project Team identifies certain circumstances where DG has been used as a distribution system asset by utilities. Such circumstances have been quite limited. Utilities occasionally employ DG assets that they own and control as a short term measure to address a local distribution investment need. In New York State the Project Team reports on the experiences of Con Edison in using mobile DG on its system. Con Edison uses the mobile generators as an emergency or "backstop measure." They are not employed to defer distribution system investment; rather, they are used to buy time while the distribution upgrade is being completed. This strategy is compared to that of Detroit Edison, a company that has elected to incorporate mobile (and stationary) DG applications into its distribution planning and capital budgeting process. Detroit Edison's strategy is one of the most robust examples of the utility ownership approach.

Other examples of utility ownership in New York include a case of a C-323 1 MVa diesel engine generator installed in the town of Denning, NY in lieu of investing in a new distribution feeder. The town was experiencing an average of 10 outages per year, and Central Hudson was exploring different scenarios to improve reliability in this location. The cost of installing a new distribution feeder was approximately $1 million, while the capital cost of the generator was $700,000.[19] Peak demand in the village is about 500 kW. Load growth in the area is < 1% per year. Therefore, this generator should be sufficient for meeting local reliability requirements for several years.

Utility programs that facilitate the deployment of distributed scale photovoltaic (PV) for distribution grid support appear more popular than DG/CHP programs. These are considered in two examples from outside New York State. National Grid has a plan to own and operate 25 MW of utility owned and operated PV in Massachusetts, in five 5MW projects; and Southern California Edison has a plan to install 500 MW of PV on commercial rooftops in 1-2 MW size projects, 250 MW to be utility owned and operated, and 250MW to be customer owned and operated.

National Grid's (NGRID) plan to deploy 25 MW of PV in Massachusetts involves the construction, ownership and operation of five 5 MW PV systems at five sites owned by the company or its affiliates. This plan developed as from the Congestion Relief Pilot projects in Everett and at Revere. NGRID recognizes the opportunity provided by these projects to study distribution system benefits including the effects of PV as a percent of the load carrying capacity of a distribution feeder, and the impact of DG on a substation and contingency loading issues. NGRID cited not only distribution system benefits but other factors that may be relevant to decision makers such as the ability to secure DG resources at a lower cost (in this case PV), to speed the time to deployment and to more readily study the impacts on the distribution system. This is relevant to New York insofar as Con Edison has expressed interest in using PV resources in constrained areas of the distribution system.

Southern California Edison (SCE) 500 MW Commercial Rooftop Solar PV Project involves the installation of 500 MW of solar PV on existing commercial rooftops in the SCE service territory at an average system size of 1 to 2 MW, over a five year period. SCE will own, install, operate, and maintain 250 MW of solar PV projects, which will primarily consist of one to two MW rooftop systems. The remaining 250 MW will be installed, owned, and operated by independent, non-utility solar providers selected through a competitive process. The cost is estimated at $875 million, resulting in a cost of $3500 per kW installed (SEPA, 2008; CPUC Solar PV Decision, 2009). The company requested a 10% contingency for potential additional capital cost spending before being subject to reasonableness review by the Public Utility Commission ( PUC). SCE also earns a return on its PV investment.

The California PUC determined that SCE's application was in the public interest, because the economies of scale and installation efficiencies resulting from deploying MW scale, multi-year projects will provide benefits to the ratepayers, and the solar PV systems promoted under the program will be located near load and can be quickly deployed. The PUC also noted that the program offers SCE and the State an opportunity to better understand the implications of interconnecting significant amounts of distributed renewable generation to the grid, and the comparative costs and benefits of different renewable energy deployment options. SCE asserts that this program will allow it to coordinate PV with demand shifts using its existing demand reduction programs on the same circuit,

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[19] Conversations with Steven Vincent, Central Hudson's Electric Standards and Utilization Engineer.

more fully utilizing distribution assets. It will also combine PV, customer demand programs, and advanced circuit design and operation into a unified system.

These two examples are relevant to New York State insofar as Con Edison has also recently offered the PSC a proposal for a multi-year program that would facilitate 25 MW of customer owned distributed PV along three networks for distribution grid support (EEPS Comments Case 03-E-0188, Jan 29, 2010). Con Edison's proposal includes the following main elements: a production based incentive, a capacity based incentive that targets networks that the company has identified as suitable for PV, and rebate funding that adds to existing NYSERDA PV rebates (with an addition for low income customers).

Con Edison's proposal included a statement about how this deployment effort will allow them to study how generation resources at the distributed scale can be integrated into resource planning for the future.[20]

An issue that the Project Team struggled with in the development of this report was the very slim historical record of the utilization of DG/CHP in distribution system planning. Experience with models utilizing customer owned utility facilitated DG/CHP assets as a substitute for distribution capital is even less well developed than the utility ownership approach.

The Project Team reviewed the Massachusetts Technology Collaborative Pilot and the Con Edison Targeted DSM program as a basis for establishing a more broadly based program that would pay an incremental incentive to projects demonstrably substituting for distribution capital investment. National Grid and NSTAR experimented with similar programs on a pilot scale in Massachusetts. The Team also studied the policy literature that discusses the outlines of potential utility programs that might implement this type of approach.

The Team did considerable outreach in support of the work in Chapter 2 of this report, conducting individual meetings, workshops, and numerous phone call interviews. The purpose was to get a thorough understanding of the issues involved in establishing a program that uses customer owned and operated assets that might substitute for utility distribution capital investments. There is a host of issues and concerns both on the utility side as well as the end user. The outreach conducted was designed to provide NYSERDA an inventory of these concerns from all perspectives. The Report goes beyond simply cataloguing parties' issues and requirements in implementing Customer Sited DG as an alternative to distribution investment, and provides specific recommendations, many of them arising from the outreach with key stakeholders.

In Chapter 2 a detailed description of HV DG Development Zone model is presented. The Project Team considered the benefits (and drawbacks) of establishing geographically targeted development zones for DG under which the utility would offer a set incentive for new DG deployment. In this chapter the Team explored the practical considerations of implementing a geographically targeted approach (e.g., defining the zone, setting incentive levels, ensuring that incentives are paid only upon a threshold of DG penetration sufficient to defer/avoid the "wires" solution).

The Scope of Work included a review of the prior RFP model that was implemented in response to NYSPSC Opinion No. 01-5 2001. This section of the report suggests several refinements to the earlier RFP process that would address problematic issues that had been identified by bidders and by the utilities that ran the bids.

The Task #3 Report will present a more thorough and detailed description of how the three models perform on various metrics that are of concern to policymakers. The reader is referred to that report for a full presentation of how each model fares on issues having to do with management complexity, transaction costs, and regulatory burden.

The utility ownership model has certain advantages particularly with respect to the utilities interest in operation and control of the asset. From the utilities' perspective there is significantly less reliability risk to relying on an asset that they own and control rather than relying on contractual arrangements and incentive payments to ensure that a third party operates the resource in a manner that insures the reliability level that the utility requires (see Table 2).

[20] Con Edison Solar Proposal, Jan 29, 2010

| IMPLEMENTATION ISSUES: | UTILITY OWNED | CUSTOMER OWNED |
|---|---|---|
| Dispatchability | Can dispatch to meet utility, economic, and reliability needs | Contractual arrangement, utility risk |
| Reliability | Can operate to meet utility reliability criteria | Contractual arrangements, physical controls, utility risk |
| Access to site | Not problematic | Contractual arrangements |

**Table 2: Implementation Issues**

There are certain other factors that tend to be favorable to utility ownership of DG assets. These circumstances include:

- Internalized Non-market benefits
- Operated to maximize utility's objectives
- Lowered transaction costs (e.g., contracting with third parties, lowered setting and monitoring incentive payments, running outreach programs, etc )
- Shorter implementation schedules (if utility owns land and can secure permits more quickly)

Some of these issues can be overcome. Where markets for capturing uncompensated benefits do not exist, they can be developed. That is the rationale for the HVDG Development Zone model, to provide a price signal encouraging DG siting in areas that provide a high value for the local distribution system.

Policymakers and stakeholders may be wary of the utility ownership model for some of the following reasons:

- Ability to wield market power
- Existing relationships with customers may create an unfair competitive advantage
- Utility dominance in the market may result in lower rates of product and service innovation

The customer owned models may be favored in circumstances where the utility is facing pressure to reduce the growth rate of distribution system capital investment. In some cases distribution capital expenditures are a key driver of increases in distribution utility revenue requirements (and consequently rates). A large proportion of the distribution system is quite aged and in need of imminent replacement. The costs of meeting the investment requirements are substantial. Using customer owned assets that are cost effectively serving as a local distribution system resource is a mechanism for leveraging new sources of private investment.

New capital investment should not simply be replacement of parts in kind – particularly where such a strategy fails to advance stated policy interests in accommodating greater local levels of clean DG penetration and facilitating more economic operation of systems of local resources (DG, DR, EE, storage) on the distribution system. Incorporating DG/CHP in distribution planning necessitates taking a longer run view of the productivity enhancing, future cost savings of investments that enable future integration and optimization of a suite of resources operated at the local area level in support of clean energy and distribution system operation objectives.

# APPENDIX A

## 3.3 CASE STUDIES

### Detroit Edison's Mobile DG Strategy

**Background.** Since 2003, Detroit Edison has been incorporating DG into its distribution planning and using DG as a temporary distribution capacity solution. Detroit Edison, a subsidiary of DTE Energy, is a regulated electric investor owned utility located in Michigan. Detroit Edison experienced electric industry deregulation in the 1990s, and divested its transmission system, but still owns and operates a large number of electric power plants. Detroit Edison started to use mobile DG back in the summer of 2002, when it used several leased mobile DG units to mitigate stressed areas on the distribution system. Since then it formally incorporated DG into its distribution planning and distribution capital budgeting process as one of the cost-effective distribution system solutions.

Detroit Edison developed and owns several mobile DG units mounted on trailers. Detroit Edison owns three 1 MW natural gas units, two 2 MW diesel units, and one 1.5 MW dual fuel unit. To date, it has deployed 16 distribution DG projects totaling 26 MW since the beginning of the program. (Asgeirsson, 2010)[21] Most of the projects are considered temporary installations, designed to operate until system upgrades have been completed (from one to five years). Detroit Edison uses mobile gen sets, internal to the distribution circuit, at a substation, and in an island mode to support maintenance work. Detroit Edison also offers a premium power program to large customers on overloaded circuits who could host generators (Jakubiak, 2004). In these cases of customer-sited DG Detroit Edison owns and operates the unit under three to seven year contracts. Customers pay a monthly fee based on the size of the unit and enjoy cost savings and increased power quality (Jakubiak, 2004).

**Detroit Edison's DG Strategy.** Detroit Edison sees DG as "one way of delivering just-in-time and "right-sized" capacity to resolve smaller short falls while minimizing the initial capital outlay" (Jakubiak, 2004). Detroit Edison occasionally has faced time and budget constraints in investing its distribution assets. Construction delays affected some planned projects. Limited capital budgets also constrained initiation of some distribution projects. Distribution projects oftentimes involve significant amounts of up-front investment in capacity to solve a small capacity problem expected in the near term future. Detroit Edison found DG provided an option to better match the scale of investment to the imminent distribution need, thereby saving limited budgets for other important projects.

A number of important elements Detroit Edison's mobile DG strategy are described as follows:

- **Earning a return**: Michigan Public Service Commission allows Detroit Edison to earn a return on the DG investment. Detroit Edison has noted that " purchasing of generators, rather than leasing, has turned out to be advantageous because the Michigan rate-setting commission tends to look more favorably on capital investments" (Journal for Onsite Power Solutions, 2004).
- P**roject screening process**: Detroit Edison uses a load flow model called the Distribution Engineering Workstation (DEW) to identify and evaluate potential DG sites on the distribution system. The DEW identified critical distribution problems; estimated capacity shortfalls at specific sites, and evaluated potential DG solutions (including size and type of DG) and the impact of DG on the grid system. Detroit Edison then conducts economic screening tests of DG over conventional distribution projects. One of the screenings compares the installed cost of DG with the installed cost of distribution projects per kW of *capacity shortfall*. Another and more important screening is to compare the annual cost of DG projects to the annual cost of distribution capital investment.
- **Community outreach**: When siting portable DG units, Detroit Edison performs community outreach to help gain acceptance of the idea. Detroit Edison shows parties a short video, which introduces the idea of portable power for grid support. (Journal for Onsite Power Solutions, 2004) When Detroit Edison needs to lease property from other entities (e.g., city, school, and church) they structure a very simple lease

[21] According to Asgeirsson, most of the units are not used as of this writing given the depressed electricity load due to the economic recession.

agreement with the counterparties (Jakubiak, 2004). Lease payments provide a welcome revenue stream to schools, churches and other organizations.

- **DG operation**: Detroit Edison uses sophisticated monitoring and remote control devices to ensure reliable DG operation. Using a number of different media such as radio, satellite, cell phone, the Internet, the monitoring device transmits operational data including oil pressure, loading level, fuel consumption and temperature. Detroit Edison also uses an automation technology that dispatches mobile DG units automatically in response to temperature.
- **Emission and noise issues**: as noted above, Detroit Edison typically places diesel DG around 300 feet from residential areas, at which distance the noise level is about 60 dB, equivalent to the noise level of conversation. In contrast, natural gas engines emit significantly lower noise and would need just 50 feet clearance to maintain 60 dB noise. When noise level is still a concern, sound baffles are often installed to accommodate concerns from the surrounding residents.

**Case Examples.** The Union Lake substation conversion project was meant to relieve an emergency overload. Nevertheless, due to the delay in construction, the project was not completed before the summer overload. The Company installed a mobile DG at the substation at an annual cost of about $61,000. This project was not only significantly cheaper than the annual cost of the substation upgrade, which was estimated to be about $137,000, but also deferred the conversion project for four years (Pace, Synapse, 2006 Report; Asgeirsson, 2004; Asgeirsson and Seguin interview, 2005).

The Milford DG project is a 1 MW natural gas generator that is located at an elementary school property. It was used to help with load relief on the 13.2 kV distribution circuit MILFORD DC8103 while the substation was being upgraded. The project has been in operation for six years and has seen two renewals of the lease agreement with the school (Asgerisson, personal communication, 2010).

In 2002, a 13.2 kV radial system near Ann Arbor, Michigan, was experiencing overloading due to larger-than-expected load growth and abnormally hot weather. The Collins substation project was supposed to mitigate this problem, but constructing the Collins substation was delayed due to issues obtaining community approval to build the substation. To temporarily solve this matter Detroit Edison installed a 2-MW diesel generator at the location of the planned substation. The unit was remotely started when temperature rose above 80 degrees F. The DG project cost was roughly equivalent to annual charges for the substation project. The construction of the DG project took just five days to complete. After seeing Detroit Edison’s commitment to serve its customers, the community recognized the need for the substation project and accelerated the approval process granting permission to build the project (Asgeirsson, 2002).

### Con Edison Emergency Generation Application

Currently Con Edison, the investor owned utility serving New York City, owns four mobile generators and a number of central power plants. The regulated central power plants owned by the company are mostly steam generators with the total capacity of 500 to 600 MW and also serve about 2,000 steam customers (Basu, personal communication, 2010). The company has been actively using emergency generators (including the four mobile generators, but the majority of the generators are leased units) to deal with distribution system maintenance and power outage events (Jolly, 2010: Jolly, personal communication, 2010). The company also occasionally used emergency generators to support its distribution system (by directly supplying a feeder or by transferring customer load to emergency generators) and to buy time when it found that it cannot build distribution circuits or substations on time. For example, the company used emergency generators to temporarily mitigate overloading system conditions while upgrading the distribution system serving the World Trade Center and upgrading the Sherman Creek substation (Jolly, personal communication, 2010).

In a way, Con Edison’s practice is similar to Detroit Edison's. The major differences are that (a) Con Edison mainly uses mobile generators for distribution maintenance and power outage events, rather than to defer T&D investment, (b) when mobile gen sets are used for deferring T&D investment, the majority of such cases, if not all, are actually for buying time for T&D upgrades because the upgrades could not be completed on time, and (c) Con Edison does not incorporate mobile DG applications into its distribution planning and capital budgeting process unlike Detroit

Edison. In other words, Con Edison's use of mobile generators is exclusively a short term or emergency solution. Still, it is not clear whether and to what extent Con Edison can incorporate DG into distribution planning and consider the use of mobile DG a few years in advance of T&D upgrades. Con Edison staff noted the difficulty of taking this approach due to the fact that the majority of its distribution systems are network systems whose capacity and load growth are so large that it is challenging to find situations where a few mobile generators can reduce enough load on the system to defer T&D investment (Jack, personal communication, 2010). Mobile generators may have to be combined with other demand side resources, such as demand response and energy efficiency measures, in order to make a difference to the distribution system.

### National Grid PV project in Massachusetts

**Background/Overview.** The New England wholesale energy and capacity markets are competitive. All Massachusetts investor owned utilities sold off their generation assets in the late 1990s when the state restructured the retail electric industry. However, more recently, the Massachusetts Green Communities Act allows utility ownership of solar PV for electric distribution companies, limited up to 50 MW per company after January 2010 (MA Green Communities Act, 2008). In response to the Act, National Grid filed a proposal on April, 2009 to construct, own, and operate a total of 5 MW solar PV facilities at 5 properties owned by the company and its affiliates. This is the first phase of the three phase programs NGRID is planning where the company will also install PV on customer sites as well as provide incentive to customer owned PV systems in the later phases. The company also requested a pre-approval of their PV cost estimates for those sites as well as the cost recovery method for the projects. The approved plan for a total of 5 MW PV capacities is expected to cost from $26.4 million to $35.7 million, with a median estimate of $31.1 million. This results in an average $6.34 per watt installed, with a range from $5.4 to $7.1 per watt for different sites, a relatively low cost per kW installed cost. The cost of the program will be determined by the annualized cost of the projects and the revenues the company would receive from selling energy and capacity as well as Solar Renewable Energy Certificates (SREC) from the PV projects into wholesale markets. The net cost will be recovered annually using the Solar Cost Adjustment Provision (SCAP) Tariff. On October 23, 2009, the MA DPU approved the company's plan (MA DPU, 2009).

**Rationales for MA DPU's Approval.** The MA DPU approved the company's plan for a number of reasons. First, the DPU acknowledged that the NGRID plan is consistent with the state's energy policy including (1) the state's RPS goal to meet 20% of its electric load by 2020 through new renewable energy and alternative energy; and (2) Governor Patrick's solar PV goal of 250 MW by 2017. The DPU also recognized that the plan is in the public interest and the cost-recovery method proposed by the company will result in just and reasonable rates because the company's PV proposal also bring about a number of benefits to the state. Such benefits, the DPU stated, includes "(1) producing electricity without emissions, thus avoiding future costs to electric consumers associated with the control of greenhouse gas emissions, (2) stimulating markets forces in creating additional solar generation in the Commonwealth, and (3) producing valuable information on the costs and benefits of installing solar generation facilities in Massachusetts" (MA DPU, 2009).

**Benefits Claimed by National Grid.** In their Application, National Grid claimed that there are a number of unique benefits that the company will bring about from their utility owned PV projects, as follows:

- Using company-owned properties for siting PV will eliminate the time required to negotiate with other parties and eliminate lease payments or fees for the use of properties owned by others. The DPU acknowledged that this will allow NGRID timely development of the PV projects (MA DPU, 2009).
- NGRID identified site specific benefits (with which MA DPU agreed). One project will be integrated with the Congestion Relief Pilot project in Everett and will allow NGRID to study the effects of PV as a percent of the load carrying capacity of a distribution feeder. Another project in Revere will allow NGRID to evaluate the impact on a substation and contingency loading issues (MA DPU, 2009).
- NGRID can buy in quantity, achieving lower prices for the system (EPRI, 2008).
- Utility owned PV projects can achieve lower net cost of service because of the ability of the utility to sell the energy and capacity to the ISO (EPRI, 2008).
- Utility owned PV projects now can take advantage of the 30% federal tax credit (EPRI, 2008).
- NGRID's PV project proposal will provide the company with "the opportunity to study the interaction of utility-scale solar generation with the distribution system under a variety of different conditions" (MA DPU, 2009).

**Southern California Edison 500 MW Commercial Rooftop PV Project**

**Background.** On March 27, 2008, Southern California Edison (SCE) filed an application with the California Public Utilities Commission (CPUC) for approval of SCE's Solar Photovoltaic Program (SPVP) to install 500 MW of solar PV on existing commercial rooftops in the SCE's territory over a 5-year period (SCE Application, 2008). Under SPVP, SCE builds, owns, and operates 250 MW of utility owned PV facilities and seeks competitive bids for power purchase agreement for electricity from the other 250 MW from independent power producers (IPPs). The targeted system size is in the 1 to 2 MW range, which has experienced limited installations in the past in the existing state's renewable energy programs. The SCE estimates the capital cost to be $875 million with the average cost of the PV facilities at about $3.5 per watt Detroit Edison requested a 10% contingency for potential additional capital cost spending before being subject to reasonableness review by the PUC. SCE also earns a return on their PV investment. On June 22, 2009, the CPUC approved the program in Decision 09-06-049 with slight modifications (CPUC, Solar Program, 2009).

**Rationales for CPUC's Approval.** The CPUC has a general policy to encourage utility ownership of distributed renewable energy generation. The Energy Action Plan I adopted by the Commission in 2003 states, "the state is promoting and encouraging clean and renewable customer and utility owned distributed generation as key component of its energy system" (CA Energy Action Plan, 2008).

In Decision 09-06-049, the CPUC reviewed some of the Public Utility Code Section 2775.5 and comments from stakeholders mainly as to how the utility ownership element of this adopted program will affect market competition and if the program is in the public interest. Public Utility Code Section 2775.5(b) required the CPUC to consider whether the program restricts competition in the solar industry, and it concluded that the program will solicit competitive bids from solar equipment manufacturers and will enhance the market for solar energy systems of one to two MW by creating a new market opportunities that currently do not exist. The PUC addressed IPPs concern that SCE's program eliminates competition in leasing commercial roof space for the use of solar PV, and modified the original plan in a way to allow IPPs to secure roof space on their own and require SCE to procure 50% of the program capacity from IPPs. With this modification, the PUC concluded that "because the adopted SPVP will allow for significant competition throughout the solar energy industry value chain, including competition for ownership and operation of the solar generating facilities, it will not restrict competition in solar energy industry" (CPUC, 2009).

In response to Public Utility Code section 2775.5(f), the PUC also examined whether the program is in the ratepayer's interest, and determined it is in the public interest because of the following reasons:

(1) The program would promote the development of additional renewable projects on existing rooftops;
(2) The program would help expand the one to two MW solar market, which under current policies has remained under-developed;
(3) The economies of scale and installation efficiencies resulting from deploying large MWs and multi-year projects will provide benefits to the ratepayers;
(4) The solar PV systems promoted under the program will be located near load and can be quickly deployed;
(5) The program can play a role in meeting the objectives of the state RPS and driving down the costs of renewable energy technologies;
(6) Large scale utility deployment of solar PV facilities along with the adopted competitive procurement process can put downward pressure on renewable energy prices;
(7) The program offers SCE and the state an opportunity to better understand the implications of interconnecting significant amounts of distributed renewable generation to the grid and the comparative costs and benefits of different renewable energy deployment options (CPUC, 2009).

Given that utility-owned renewable generation is a new program approach, CA PUC intends to carefully monitor the program's progress, to examine ways in which the program can be improved, and to improve the design where and when appropriate.

**Benefits of Utility Owned PV Systems.** SCE argues that the utility is in the best position to promote large scale PV deployment on the commercial rooftop spaces for the following reasons (SCE Application, Case 08-03-015):

(1) SCE can use established electric supply arrangements with vendors and commercial lessors who are also its longstanding customers, and who view the utility as a stable, competent, reliable business partner (whereas 'most solar PV developers have been in business for only a few years')
(2) SCE can obtain volume discounts not available to most PV developers
(3) SCE has a strong balance sheet and procurement expertise that enables it to negotiate effectively with rooftop owners and vendors
(4) SCE will refer building owners/developers to its Energy Efficiency group to identify efficiency opportunities for new structures considering PV
(5) Utility field personnel can effectively monitor and cost-effectively repair systems
(6) SCE can coordinate PV with demand shifts using its existing demand reduction programs on the same circuit, more fully utilizing distribution assets
(7) SCE is uniquely situated to cost-effectively combine PV, customer demand programs, and advanced circuit design and operation into a unified system
(8) SCE involvement substantially increases the chance that 250 MW of PV will become available to meet State RPS goals
(9) SCE will share with other entities, in California and elsewhere, its experience concerning PV interface issues, forecasting and scheduling, training and best practices for 1-2 MW facilities, and streamlining of tariff applications and local and State codes.

### Austin Energy's CHP Solution at Dell Children's Hospital

Austin Energy is a publically owned municipal electric utility located in Austin, Texas. Austin Energy serves 388,000 customers in the City of Austin, Travis County, and parts of Williamson County. Also functioning as a city department, Austin Energy returns profits to the community on an annual basis. Austin Energy's generation mix includes 2,600 MW of nuclear, coal, natural gas, and renewable energy sources. The utility offers highly successful renewable energy, green energy, and energy efficiency programs to residential and commercial customers (Austin Energy Profile, 2010).

Dell Children's Medical Center, a 170-bed hospital located in Austin, first contacted Austin Energy about contracting for a CHP generator to be located on the hospital site (TAS, 2010). Dell was interested in becoming the first hospital in the world to obtain Platinum LEED® certification, and hoped the CHP installation would assist achieving this goal (TAS, 2010; Collins, 2010). Austin Energy would own and operate the unit on the hospital site, and in turn the hospital would purchase the power and chilled water from the plant at tariffed rates over a 30-year term (TAS, 2010).

Given its history of supporting renewable energy, green buildings, and energy efficiency, Austin Energy accepted the request as an opportunity to experience the advantages and disadvantages of CHP generation. Austin Energy further hoped that the CHP experience would contribute to improved customer relationships and reliability, two long-standing goals of the company (Collins, 2010).

Austin Energy contracted with Burns & McDonnell for engineering, procurement, and construction of the unit, which was completed in 10 months and initiated operation in 2006 (TAS, 2010). Burns & McDonnell was able to secure cost share funding through a grant from the U.S. Department of Energy (DOE) and the Oak Ridge National Laboratory (ORNL) (Burns, 2010). The system is comprised of a 4.3 MW Solar Mercury 50 combustion turbine with a HRSG and absorption chiller (TAS, 2010). With a 1.5 MW diesel backup generator and two grid feeds from separate substations, the system is exceptionally reliable and supplies 100% of the hospital's electricity, heating, and cooling needs (TAS, 2010).

Both Austin Energy and Dell have benefited from the CHP project. Austin Energy receives the stability of a long-term contract while the hospital enjoys a reliable power supply (Collins, 2010). Dell has also saved $7 million in capital outlay by outsourcing power, heating, and chilled water needs to Austin Energy (Bullock, 2010; Collins, 2010). In addition, the CHP unit operates with very low emissions, enabling the utility and the hospital to meet environmental goals and minimize regulatory hurdles (Collins, 2010).

Overall, Austin Energy encountered very few regulatory barriers costs in implementing the Dell CHP project.

Environmental permitting was simple due to the unit's low emissions, and Austin Energy's role as a city department simplified other regulatory matters. Coordination of the parties involved significant time and effort upfront, mostly because neither Austin Energy nor Dell had prior experience with similar projects. Connection to the grid was not difficult (Collins, 2010).

From a project management standpoint, the greatest challenges to the Dell CHP project have come from allocation of fuel and equipment between power production and non-power production and maintaining 24-hour staffing. Operating cost accounting can be complex and subject to fluctuating natural gas prices. The plant has experienced three outages early in its four-year operation. These outages were caused by problems switching to the grid power feed, and Austin Energy is working to eliminate such problems in the future (Collins, 2010).

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

Comparative Analysis of DG Implementation Models
Task #3

Prepared for the

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## SUMMARY

This report provides a narrative summary of Task 3, which is a comparative analysis of the risks and benefits associated with the three DG deployment models described in Task 2. The complete comparative analysis exists in a matrix in the form of an excel spreadsheet, which provides a clear form for comparison. The issues considered in the comparison matrix include the following overarching issues, with both risks and benefits described with respect to each implementation model:

- Regulatory Burden And Management Complexity
- Project And Program Cost
- Ease Of DG Integration
- DG Relocation Flexibility, Deployment Lead Time
- DG Interconnection
- Reliability
- DG Market Development
- Meeting Utility RPS Requirement
- Resource Integration
- Utility Ownership Of DG

The sections of the narrative below correspond to each of these overarching issues. Unless otherwise specified, the parenthetical page number references refer to the corresponding pages of the Task 2 report, "Deployment Of Distributed Generation For Grid Support And Distribution System Infrastructure: Alternative Utility DG Deployment Strategies." The Project Team would like to acknowledge the assistance of Todd Olinsky-Paul and Thomas Kelly in the preparation of this Final Task Report.

# 1 REGULATORY BURDEN AND MANAGEMENT COMPLEXITY

The overarching issues related to regulatory burden and management complexity include several sub-categories. These include the issues of cost recovery, program management, project development, monitoring and operation, customer screening, customer contracting, emissions, sales of energy and capacity, and noise and space.

## 1.1 Cost Recovery

Cost recovery is a critical issue and depends on standards imposed by regulators, which stems from the regulatory requirement that utility investments be in the public interest, prudent and just and reasonable. For each of the implementation models, all utility program costs or investments contributing to a DG/CHP project must be justifiable as cost effective and in the public interest in order to receive cost recovery. Lost net revenue may be an issue for either type of model, but is at least partially offset by return on equity under utility ownership models.

With utility-owned DG investments, in order to qualify for regulated rate treatment, including return of and on the investment, utilities need to spend time and resources to ensure that CHP/DG projects are in the public interest and the costs of such projects are prudent and just and reasonable. They may also need to spend time and resources demonstrating that such standards have been met if recovery is challenged in a rate case, but the recovery framework is the same as for other utility costs. In general, the successful use of the RFP model historically by utilities has been preceded by adoption of measures that ensure cost recovery. For that purpose, the RRFP model incorporates separate checks and balances to ensure cost effectiveness, such as the involvement of the Technical Evaluation Panel (TEP) to evaluate proposals. In the HVDG model, the program design presumes that the utility already received regulatory cost recovery guarantees before posting the prices.

## 1.2 Program Management

All three models require utility time and resources to manage the programs. The Utility model would be managed like any other utility program, benefitting from existing expertise and efficiency of other utility managed programs. When utilities decide to develop, design, and construct DG on their own, utility-owned DG projects/programs become more complex, but, to the extent that utility-owned resources are installed by third party contractors, the same efficiencies would accrue as utilities routinely manage construction work by others. Still, depending on the volume of work, utilities may need to create a new department or assign/hire dedicated staff who can work on utility-owned DG projects. The RRFP model would be co-managed by the utility and the technical evaluation panel (TEP). This collaborative management approach would set the incentive, market the program, and administer the application and eligibility review processes. The acquisition of the resource would be conditional upon approval by the New York State Public Service Commission (NYSPSC). The HVDG model would be managed by the local distribution utility, who would publicly post and adjust spot incentives, administer the application and eligibility review process, oversee performance payments, and submit costs to the NYSPSC for adjustment through the appropriate mechanism.

## 1.3 Monitoring and Operation

Monitoring and operation of the DG resource is an important attribute for each of the models. In order for DG/CHP projects to be effective as distribution resources, the units will likely need to be controlled by the utility either directly or indirectly through programmatic elements. In the utility-owned model, monitoring and operation are performed by the utility; however with the customer-owned models, programmatic elements will be necessary to manage the monitoring and operation of the resource to the satisfaction of the utility. This added level of complexity associated with the customer-owned models will likely involve additional time and expense to manage.

## 1.4 Customer Screening

One form of the utility-owned DG model deploys DG units along distribution systems (e.g., as in the mobile DG example from Detroit Edison discussed below), on public property such as parking lots and subway depots, and on utility property (e.g., solar PV examples from SCE and NGRID), and does not require host customer screening. For utility-owned DG that uses customer sites for DG projects and for the customer-owned DG models, there will be considerable amount of time dedicated to identifying and screening the customers who are most suitable for participation. For CHP projects, where both power and thermal needs of the customer must be considered, this process will take additional time. With the customer-owned models, the burden to identify appropriate hosts will lie with the DG developer.

## 1.5 Customer Contracting

With a utility ownership model, as with central station power plants, there may or may not be a counterparty for the development, ownership or operation of the generating unit. Depending on the technology and location, there may be a site landlord or a steam or heat customer to engage in a contract. The customer-owned models will need to contractually obligate the customer operating the resource to make the unit available and operating at critical times in order for DG to be used as a distribution resource. In both customer-owned models, the utility would contract with its customers for the prescribed amount of time to match the deferral value. For the RRFP model, developers would contract with the customer who would then remit to the utility for contracted payments. For the HVDG model, depending upon the deferral price, the customer would contract that amount with the utility.

## 1.6 Emissions

Depending upon the type of fuel used for the resource, New York State Air Resource regulations may apply to DG projects, and the appropriate permits must be acquired. The utility-owned DG model includes mobile generators that can be used to defer T&D system upgrades as demonstrated by Detroit Edison. If such mobile generators are run by diesel fuel (as is typical), and if they are not eligible to be treated as emergency generators in New York (perhaps, because they are incorporated in T&D system planning or due to projected annual run times), emissions from diesel units would not likely meet the current emission regulations in New York.[1] Adding emission control technologies such as a selective catalytic reduction (SCR) system could cut the emission enough to allow diesel engines to comply with regulations, but are very costly to install. SCR requires up to $250,000 additional capital cost for a 1 to 2 MW unit (MECA, 2009). On the other hand, natural gas engines have significantly lower emission rates and could be viable for mobile DG options. The NOx emission limit for stationary compression ignition internal combustion engines under the current air regulation is approximately 6.79 lb/MWh while the emission rate of natural gas engines range from 0.096 to 1.25 lb/MWh (NY Air Regulations, US EPA Catalog of CHP Technologies).

## 1.7 Sales of Electric Energy and Waste Heat

In some situations, utilities may need to sell electric energy to the wholesale market if, for example, it cannot be treated as load reduction for reliability and market purposes. Nevertheless, sales of energy may not be complicated if output does not require scheduling of energy output and pricing, i.e., if the unit is simply a price taker. This is likely the most to be the case when DG is mainly used for T&D support or when the output of renewable DG cannot be scheduled. When utilities own CHP as Austin Energy in Texas is doing (see Task 2, Appendix A), they have to sell not just energy but steam or other forms of waste heat to their customers. Selling steam is within the ordinary

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[1] According to New York Air Regulations, emergency power generating units, such as those that are currently used by utilities to support T&D system during T&D system upgrades or to buy time when system upgrades are delayed, are exempt from permitting as long as they operate less than 500 hours per year (NYCRR 201-3.2(c)(6)). Still, given that the nature of DG envisioned for distribution planning is mobile, non-emergency or both, the air regulations for non-emergency generators are likely to be more applicable for the utility DG model discussed here.

scope of business for Con Edison. which has been operating steam generators for its steam customers for many years, but it may be quite novel (or a "flashback") for other utilities.

### 1.8 Sales of Capacity

Dealing with capacity from DG does not appear complicated given that utilities are familiar with the capacity market in their role to meet installed capacity requirements. Also capacity from DG, if it is owned by a utility, would likely be regarded as self-supply resource by utilities (LSEs), the amount of which will be subtracted from the capacity requirement the company needs to purchase via bilateral contracts or from the installed capacity market (NYISO, 2010).

### 1.9 Noise and Space

Noise and space are generally not a significant concern for some DG technologies such as solar PV, fuel cells, and microturbines; however noise and space can be significant issues for engines and turbines, aside from CHP applications. (Facilities that support CHP can often provide indoor industrial space and noise control.) When engines are used outdoors for mobile DG applications to support T&D system, noise and space become a significant matter for a densely populated city like New York. Detroit Edison uses mobile DG for T&D support and usually places diesel DG around 300 feet from residential areas, at which distance the noise level is about 60 dB, equivalent of the noise level of people talking on the street (Asgerrisson, 2004). It would be challenging to find such space in New York City in a useful DG T&D support location, although utility substations, empty industrial sites, under highway overpasses, subway depots, or the like could possibly host engines and mitigate noise concerns. Natural gas gensets operate more quietly than diesel units, and would face fewer siting challenges in NYC.

# 2 PROJECT AND PROGRAM COST

## 2.1 System Installed Cost and Project Cost

When utilities install and own DG resources, there is significant potential for them to face system capital costs lower than those non-utility owners would face, depending on the type of DG technology used. Some utility-owned DG projects can be large scale either in individual unit size or collectively in capacity with numerous projects, while others such as CHP may not be much different in size regardless of who own the projects. The nature of large scale projects allow for (a) economies of scale in planning and operation, (b) bulk purchase and (c) standardization of products and installation practices, all of which reduce the project cost. This is especially true for technologies like solar PV, the cost of which still has potential to decline with widespread installations (DOE EIA 2010, Navigant 2004). For example, Southern California Edison is planning to install 250 MW of utility-owned PV on commercial rooftops over five years. The program targets an average system size of 1-to-2 MW. The cost is estimated at $875 million, resulting in a cost of $3500 per kW installed (SEPA, 2008; CPUC Solar PV Decision, 2009). (See Task 2, Appendix A for the SCE's PV example and another PV project example from NGRID.) Another example is Tucson Electric's 5 MW Springerville PV generation station, which had a system cost of about 30% less than other PV systems installed around the same time due to the incorporation of standardized products, volume purchasing and an efficient array field design and installation (Moore, 2005). According to Tucson Electric, a key to cost reduction was achieved through "an identical copy of a standardized array field configuration that uses the same hardware components, wiring topology, and structural mounting plan" (Moore, 2005).

It is also possible that an incumbent utility may have advantages in the access to information or the cost of information for pre-development activities. The most important of these would likely be information about current and future T&D relief needs. When all market participants have access to the same information on deferral value of a T&D project, multiple parties may vie to provide a least cost solution in an RFP type process, but utilities may know long in advance which circuits will need expensive upgrades, giving them a potential competitive advantage in siting DG to defer those upgrades. On the other hand, utilities often have commercial and industrial customer account representatives who would know large customers and their facilities in detail. This knowledge could allow a utility to identify good prospects for hosting a DG unit, an advantage difficult to erase in an RFP.

## 2.2 Cost of Capital

The cost of financing a utility-owned, rate-regulated DG project is typically lower than the cost to other types of private companies. This is due in part to a lower cost of equity and debt for regulated monopolies compared to the unregulated private market and in part to the ability of utilities to obtain financing with a larger debt ratio than other "unregulated" businesses. Together with utilities' ability to recover costs over a longer term than most unregulated entities can afford, these savings generally help lower the cost of capital for utilities compared to unregulated companies. Further, if utilities offer third party developers long-term power purchase agreements or feed-in tariffs, which guarantee long-term payments to DG projects, the cost of capital for private companies is also reduced. In either case, the lower financing costs would benefit both utilities and consumers.

Another aspect of capital cost may favor one of the models or the other, depending on the utility's circumstances and the state of capital markets. The 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. Some utilities have ready access to capital and confidence in their ability to obtain recovery for rate base additions through their Commission. Such utilities will see capital additions as a valuable activity. Others are capital constrained and would not. Such capital constrained utilities could see negative impacts on their bond ratings and cost of capital if they pursue capital additions for needs that could be met in other ways, as over-leveraging will be penalized by risk averse financial markets.

One recent example of this is the history of CECONY, as set out in the 2009 Comprehensive Management Audit by Liberty Consulting. Liberty Consulting concluded that an increase of more than 100% in the Company's capital spending levels increased revenue requirements faster than revenues, leading to higher costs for new capital and serious concerns about the company's ability to raise further capital. The implication here is not that investment in DG is risky; quite the opposite if the DG option is the least cost solution for T&D constraints. Rather, the point is that for a company in such a financial situation, customer ownership models may be favored, at least while that situation continues. For a utility with problems accessing or carrying debt, non-utility ownership models for DG could make more sense for the utility and for ratepayers. Still, the balance is likely to be utility specific and change over time. It should be noted that this issue does not depend on whether DG is the least cost option for a given T&D constraint. When DG is the least cost option, it will eventually reduce the amount of capital and debt spent on dealing with T&D constraints and investments associated with them. Nevertheless, for some utilities, other aspects of their financial situations may interact with DG investments in ways that make either type of investment (T&D or DG) quite difficult. In such cases, utility-owned DG models may be untenable.

In some situations, a third capital cost issue may arise. Investment rating agencies treat the payments required of utilities under long-term power purchase contracts as a debt obligation, at least in part. Thus, utility ownership can be attractive for utilities and ratepayers inasmuch as it can avoid that type of burden on the utility balance sheet. Still, that potential benefit may be irrelevant if the utility has a weak balance sheet to start with. Conversely, if a utility is capital constrained, i.e., 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, but that perceived benefit (avoiding the need to raise or spend capital) may partially offset by any commitment to future power purchases from customer-owned DG, depending on rating agency treatment of purchased power obligations.

In general, financing costs, including transaction costs, are heavily influenced by risk. Lenders are wary of a variety of issues, such as risk of default and complicated and varied contract forms. With a streamlined or standard form contract, lender risk premiums will go down, and financing costs will be reduced. Longer lead times would also allow developers to secure more attractive financing, which could enhance the economic benefits for all the parties involved. The utility posted price in the HVDG model may lower the cost of financing because bidders will have certainty about their bid costs in securing the contract.

## 2.3 Administrative and Transaction Costs

### *2.3.1 Utility Ownership Model*

Utility administrative and transaction costs mainly occur when utilities are marketing the program, searching for potential DG and customer sites, reaching out to potential customers, arranging lease agreements with customers to install DG at customer site, and during DG interconnection and operation. In general, if utilities own DG resources, they can avoid the time and expense that otherwise would be required to deal with customer-owned DG. For instance, DG interconnection becomes easier if DG is owned by utilities because utilities do not need to process applications for numerous customers. DG monitoring and control would also be simpler and more cost effective because utility ownership does not require utility-customer agreements for monitoring and control of customer-owned DG units. With utility-owned DG resources, when utilities use their own or affiliates' properties, buildings and substations to site a DG resource, leasing costs are also eliminated. Where the utility sites a DG unit on private property, a situation unique to the utility-owned DG model, transaction costs ought to be minor, as lease agreements could be a short, standard form document.

Seeking proposals from customers willing to help the utility's T&D system with a DG proposal requires a significant amount of marketing time, dealing with inquiries by potential participants, and screening and selecting the winning participants. Identifying customers with sites appropriate for DG as a T&D solution also requires a considerable amount of time and resources, and is necessary regardless of who owns the DG units.

### *2.3.2 Customer-owned Models*

The utility management of an RFP for customer-owned DG projects requires a significant amount of utility staff administrative time and resources (page 36). The costs associated with administering an RFP include activities undertaken in creating and executing the RFP process, marketing the program, handling inquiries from potential participants, and screening and selecting the winning participants, as well as the costs of finalizing and executing power purchase contracts. Unlike the HVDG model, the RRFP process entails more granular management of the public-procurement process. For private DG developers, bid preparation costs associated with an RFP process can be significant, but are likely to be significantly lessened with a standard offer. These costs can be significant and potentially deterring qualified firms because those bid costs are at risk if a firm bids and does not win a contract.

Nevertheless, the customer-owned implementation models both provide mechanisms to address and lower these types of costs. The RRFP collaborative group is intended to address administrative costs by determining the most effective strategies for administration and lowering transaction costs (page 36). Under the RRFP, DG developers would be provided with adequate time to prepare their bids, secure financing and implement the project. Transaction costs for developers are increased when utilities do not provide ample time for developers to secure a customer site for the program. Extending the time required for the project could allow for developers to seek lower cost bids from subcontractors for engineering services (page 37).

Transparency on the deferral values specific to a particular location will provide knowledge that will allow private developers to bid more accurately and discriminately, where multiple parties vie to provide a least cost solution, and thus will lessen administrative costs for the utilities (pages 13 and 26).

With the HVDG model, a simple proposal process allows for low application and proposal costs to the resource owner, and a first-come, first-serve review process with pre-established standard conditions simplifies and reduces costs to the utility to administer the selection process. These costs are expected to be lower than the costs expected with the RRFP model. For example, the development of a simple, standard form agreement between Con Edison and DG/CHP developers will lower legal costs (page 36).

## 2.4 Tax Credits

Federal tax credits often have a significant impact on the rate of return for DG projects. Until October 2008, utilities were not eligible for federal investment tax credits (ITCs) on renewable energy and DG projects. The solar industry claimed that the federal ITC is critical for the economics of utility-owned projects (SEPA, 2008). In October 2008, the Energy Improvement and Extension Act of 2008 (H.R. 1424) extended the ITCs for eight years and also extended eligibility to utilities. Existing law provides ITCs for solar energy, fuel cells and microturbines and that was extended to new small wind-energy systems, geothermal heat pumps, and CHP systems (DSIRE). Solar Electric Power Association states that the removal of the utility exclusion from the federal solar investment tax credit, along with other current conditions such as lower PV module prices, has made photovoltaic a viable ownership option for utilities to consider (SEPA, 2009).

# 3 EASE OF DG INTEGRATION

With respect to DG integration, the utility ownership model is the model best suited to integrate DG into the distribution grid with ease. This is because utilities are in the best position to identify the most beneficial sites and system sizes for their network. The NYSPSC indicated recently in the RPS proceeding, that "utilities are not only uniquely situated to identify locations within their distribution networks that are in need of significant upgrades or replacement where added distribution support may be desirable but also that utilities are in the best position to analyze system performance and the impact of any installations on their respective distribution systems" (Case 03-E-0188, RPS Order, 2010, page 35).

With the customer-owned implementation models, the utility will need to respond to a variety of project-specific proposals that involve a range of different technologies. Fielding these proposals and managing the requirements and specifications to interconnect a variety of DG technologies at different locations on the distribution grid will undoubtedly complicate the integration of DG.

The Refined RFP process is intended to integrate DG into the distribution grid with more ease, by recommending certain adjustments based on the lessons learned after the three-year DG pilot program ordered by the NYSPSC in 2001. By matching RFPs with service territories that contain more attractive DG/CHP economics, implementation in those areas will tend to be more successful. Inviting utilities into the process for a greater role in project development, and initiating a collaborative process that solicits stakeholder input and develops best practices are also actions that will ease implementation. Exploring the synergies in grid congestion between the local distribution utilities and the NYISO will help accomplish more accurate identification of locations where DG economics make sense. Finally, the provision of guidance on the evaluation of reliability will serve to save time, create efficiency in project development, and ultimately better ease DG integration.

Both the posted incentive and standard offer process outlined in the HVDG model are also intended to ease DG integration, despite the complexities associated with customer-owned models. Clear price signals resulting from accurate deferral values will improve DG economics. A streamlined process with a first-come, first-served nature selection process saves the distribution utility reviewing time over the RRFP process.

# 4 DG RELOCATION FLEXIBILITY, DEPLOYMENT LEAD TIME

Periodically, distribution problems emerge on the grid with so much urgency that they must be addressed rapidly. These urgent situations, often related to T&D congestion, are routinely addressed by utilities with the deployment of utility-owned DG resources. Certain DG technologies, such as mobile DG and PV, can be located and relocated to best meet the changes in distribution loading condition. With respect to alleviating T&D constraint, utility-owned DG projects, especially those located on distribution systems or utility properties, have an advantage over customer ownership forms because they save time on site and customer selection, contractual relationships with private parties, interconnection agreements, and monitoring and control of a customer-owned resource. Even utility-owned DG models located on customer sites will save time and resources on interconnection agreements, and monitoring and control of a customer-owned resource.

DG project lead time can be relatively short and can be extremely short for utility-owned mobile DG applications. These benefits are demonstrated in the cases of Detroit Edison and National Grid (pages 4 and 38). Most private developers who were interviewed require a lead time of 12 to 18 months, similar to lead times that a traditional distribution solution requires. Private developers desire these lead times primarily because of the necessary time to identify host customers and to secure adequate financing for a project (page 37). Utilities also have to plan for lead times based on project deferral timelines. With the HVDG implementation model, the location incentive would be posted with expectations on lead time, allowing for greater efficiency in planning a project and cost savings.

# 5 DG INTERCONNECTION

In a 2009 study, the Solar Electric Power Association (SEPA) stated that, “the major utility obstacle for interconnection [of DG] is the utility’s desire to ‘protect’ the grid,” by requiring “highly reliable” and “continuously operat[ed]” DG resources (Sautter, 2009).

With utility ownership of DG, utilities are better suited to improve DG interconnection and technologies, although possibly not their cost or flexibility in application. The development of more simplified and standardized interconnection requirements for DG is likely to benefit utilities in the long run (Sautter, 2009). SEPA points out that when a utility decides to own and operate a DG resource, the utility also gains an opportunity to “expedite the development of simplified interconnection” and the “education to identify the lowest cost (both in hardware and process) to assure grid reliability is not affected by PV systems” (Sautter, 2009).

Both NGRID and SCE photovoltaic projects (referred to in the Task 2 case studies) demonstrate the benefit to utilities of understanding and facilitating DG interconnection. For example, MA DPU stated that NGRID’s PV project proposal will provide the company with “the opportunity to study the interaction of utility-scale solar generation with the distribution system under a variety of different conditions” (MA DPU, 2009). The CA PUC stated that the SCE’s PV program offers SCE and the state an opportunity to better understand the implications of interconnecting significant amounts of distributed renewable generation to the grid and the comparative costs and benefits of different renewable energy deployment options (CPUC, 2009).

In February of 2009, New York standardized the processes for all applications that run parallel to the grid up to 2 MW. Projects require external disconnect switches and size limits are capped at 2 MW (Page 34). This new standard is beneficial for the customer owned DG models, but the capacity limit is still small for many commercial scale DG projects. Network for New Energy Choices argues that increasing the cap up to 20 MW would provide additional incentive for large businesses to invest in DG technologies (Network for New Energy Choices, 2009).

# 6 RELIABILITY

Utilities and DG developers vehemently disagree on whether DG serves to improve or weaken grid reliability. The contradiction was explained in a 2002 article by Roger Dugan of Electrotek, who pointed out the differing perspectives of the utility versus the DG owner. "Almost all of the literature promoting DG also claims that DG improves reliability. Still, utility engineers often will not give DG any credit for reliability improvement, and in fact, they often will give reasons why it will decrease reliability" (Dugan, 2002). Utility concerns about reliability, particularly with respect to radial distribution systems, include issues related to the "multiple sectionalizing switches that allow for reconfiguration of the radial circuits during emergencies, or for balancing loads between substations during normal conditions" (Dugan, 2002).

Detroit Edison uses sophisticated monitoring and remote control devices to ensure reliable DG operation. Using a number of different media such as radio, cell phone and the Internet, the monitoring device transmits operational data including oil pressure, loading level, fuel consumption and temperature. Monitoring equipment is duplicated for safety and reliability (Pace, Synapse, 2006 Report). Also, relay protection is often installed to DG units in addition to the protection device embedded in the DG system (Pace, Synapse, 2006 Report). The company also uses an automation technology that dispatches mobile DG units automatically in response to temperature.

Utilities typically prefer to control the operation of DG units that are relied upon for distribution system support rather than engage those resources for distribution support if they operate under customer control, primarily for a desire for physical assurance that the resource will operate during system peaks. For example, Con Edison operates three small gas turbine generators (one located on W. 59th St and two located on W. 74th St.), which were built over forty years ago. These units were treated as load relief resources for nearby substations and feeders despite the fact that those generators are larger in scale than most customer-owned DG, which carries with it a greater reliability risk than most customer-owned DG.

Nevertheless, there are alternatives to 100% physical assurance that utilities typically demand for customer DG resources, such as (1) reducing physical requirement to just peak load hours for the distribution system (Con Edison is considering this option for its targeted DSM program); (2) assessing penalties for non-performance; (3) diversifying the DG resources deployed in a particular location; and (4) allowing other distributed energy resources such as EE and DR in addition to DG (page 32).

Furthermore, according to a study performed by Energy & Environmental Analysis (EEA), when a group of DG units operate as a system, reliability is increased. It was noted in the study, if one DG unit, independent of others, has a reliability risk of, say, 3%, when two such units are used, the overall reliability risk drops to 0.1% (Hedman, 2004). By creating local redundancy and diversity with a combination of DG and other demand side resources, utilities can relax their assurance and load shedding requirements during contingency events.

With both customer-owned models, compensation for energy and capacity from DG units, including performance based incentives or penalties, may be pre-defined. Relaxing physical assurance requirements to only peak periods may induce more cost-effective DG to enter the market.

# 7 DG MARKET DEVELOPMENT

Two of the barriers to the wider spread of customer-owned DG technologies are the lack of upfront capital for development and the short payback periods demanded by customers and developers. Utilities can overcome these barriers by providing incentives to customers who want to install DG units. Still, even with incentives (for ongoing performance) and rebates to purchase clean DG technologies, many customers still face a barrier in terms of lack of up-front capital. In contrast, utility ownership models, in general, do not encounter these barriers if installed DG qualifies for regulated rate recovery. Utility-owned but customer-sited technologies, such as utility installed and owned rooftop solar panels, can deliver the benefits of clean energy to customers without the necessity of a large up front financial investment by the customer. Utilities can often more readily obtain the necessary capital due to their size and access to capital, and can amortize PV investment and recover over a longer term than most customers.[2]

Another related benefit of utility ownership models is that a large scale utility DG program (e.g., SCE's 250 MW PV plan) could provide certainty in terms of actual delivery of DG installations, while a customer ownership model that aimed at the same scale of DG deployment would tend to have some uncertainty as to whether they could actually be delivered.

The success of customer-owned models will depend on the effective marketing of the model to those who recommend, bid, develop and own/operate DG/CHP systems. The incentive offered must be designed to contribute meaningfully to a project owner's economic fundamentals in terms that customers relate to, such as internal rate of return (IRR) or simple payback period.

Customer-owned DG models generally viewed as giving more impetus to developing the competitive market for DG service providers (turnkey operators, installers, engineers, maintenance companies, etc.) because private companies participating in DG projects presumably face fierce competition and make every effort to find and offer cost-effective DG/CHP solutions for their customers in all aspects of DG development and operation including engineering, designing, procuring equipment and fuel for, building and maintaining and operating DG projects on their own or using other private companies (pages 34-35). However, utility ownership models can provide similar kinds of benefits if implemented via contracting between the utility and such providers, although the result may be somewhat less diversity if utilities favor consolidated master contracts for many DG projects.

[2] For example, SCE is recovering the cost of utility-owned PV assets over 20 years. See http://docs.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/116784.htm

# 8 MEETING UTILITY RPS REQUIREMENTS

Production of renewable energy credits (RECs) for renewable portfolio standard (RPS) compliance is a possible benefit available from DG projects that qualify as renewable energy for that purpose. Both utility ownership and customer ownership models may provide a significant benefit in the form of a vehicle for aggregating qualifying generation. This is because many REC clearinghouses (such as ISO generation information systems) issue such certificates only in minimum amounts of one MWh, a utility managed DG program can bundle the generation together for that purpose, if the clearinghouse rules permit. For a utility ownership model, this is straightforward. Under a customer ownership model, there would be a need to specify terms and conditions that govern ownership of and compensation for any RECs produced.

# 9 RESOURCE INTEGRATION

Active utility involvement in DG projects could allow for economies of scope and thus reduce the cost of DG projects. Economies of scope are possible when a utility having existing energy efficiency and/or demand response programs promote DG projects by utilizing the existing program infrastructure, staff, marketing methods and channels and by targeting the same customer base at the same time as promoting energy efficiency and/or demand response resources at customer site. A case in point is SCE's 250 MW utility PV program. In the case study of that project, SCE noted the following points as the benefits of its utility-owned PV program:

1. SCE can refer building owners/developers to its Energy Efficiency group to identify efficiency opportunities for new structures considering PV;
2. Utility field personnel can effectively monitor and cost-effectively repair systems;
3. SCE can coordinate PV with demand shifts using its existing demand reduction programs on the same circuit, more fully utilizing distribution assets; and
4. SCE is uniquely situated to cost-effectively combine PV, customer demand programs, and advanced circuit design and operation into a unified system.

Coordination and integration of DG with other programs and resources will be easier if DG is owned by a utility, especially for (2) and (3) mentioned above.

# 10 FEASIBILITY OF UTILITY OWNERSHIP OF DG

In 1996, the New York State Public Service Commission (NYSPSC) initiated a proceeding to restructure the electric utility industry, fundamentally changing the market and opening the industry to competition. (PSC, 1996) In order to create a competitive generation market, the PSC directed the investor owned utilities (that at the time owned transmission, distribution and generation) to unbundle and divest most of their existing generation, although the PSC did not specifically prohibit a distribution utility from owning generation in the future. As a result, utilities generally divested their generation resources, with the exception of some small hydro generation, Con Edison's steam generators, and certain nuclear power plants (that were subsequently divested). Since then, distribution-utility ownership of generation has been determined on a case-by-case basis when the issue arises in proceedings. The principles applied in those cases provide some useful insight for examining the circumstances under which utilities can own DG for the purpose of distribution system planning and operation.

The most relevant principle for the ownership of DG by utilities is stated in the Vertical Market Power Policy (VMPP) Statement of 1998 regarding a T&D utility affiliate owning generation. While the VMPP Statement provided that generation divesture is "a key means of achieving an environment where the incentives to abuse market power are minimized," it also stated that the ownership of generation by a T&D company is allowed if there is a demonstration of "substantial ratepayer benefits, together with [market power] mitigation measures." (PSC Case 96-E-0990, 1998) The VMPP has been relied upon to examine the appropriateness of generation divesture and ownership in past cases. Recent examples include the National Grid acquisition of KeySpan in 2007 and the Iberdrola acquisition of NYSEG and RG&E in 2008.

In contrast, there are only a handful cases since restructuring that involved DG ownership by a distribution utility itself. While the VMPP Statement was not cited in those cases, the spirit of the Statement was reflected. Brief overviews of two such cases are provided below:

- In Opinion No. 01-5 issued on October 26, 2001, t he PSC directed New York's investor-owned distribution companies to implement a three-year pilot program designed to test whether DG could cost-effectively defer the need for significant investment in distribution system infrastructure. (PSC Case No. 00-E-0005, 2001) The pilot focused on customer owned DG projects, but allowed utilities and utility affiliates to bid DG projects. This could reflect the PSC's recognition that utility ownership of DG may provide some public benefits. Still, neither the PSC's Opinion No. 01-5, nor the recommendation report that the PSC endorsed in the Opinion discussed utility ownership of DG resources in detail beyond mentioning one stakeholder who claimed that utility ownership allows for realization of the full benefits of DG. The recommendation report, however, did clearly state that utility affiliates are allowed to participate in the pilot provided that "utility does not extend preferences to its affiliates in violation of code of conduct requirements." (PSC Case No. 00-E-0005, Appendix B, 2001)
- In proceeding leading up to its April 2, 2010 Renewa ble Portfolio Standard (RPS) Final Order, the PSC along with various stakeholders reviewed the RPS customer-sited tier program to address the geographic imbalance between the regions of the state from which System Benefits Charge (SBC) money is collected and those where SBC-funded renewable energy projects are installed. (RPS Order, Case 03-E-0133, 2010) The Order also examined utility ownership of PV as a possible eligible renewable energy resource option for the proposed customer-sited program in downstate New York. The PSC stated that "the retail distributed solar photovoltaic market is demonstrably competitive and utility involvement in the market, at this time, does not appear necessary to address any deficiencies." (RPS Order, 2010) Nevertheless, the PSC also stated that "there may be merit in allowing utilities to participate further in this program, at a later date, if it were to be found that private investment is not available or sufficient in areas where utility ownership may be better targeted, more cost-effective and beneficial." (RPS Order, Case 03-E-0133, 2010) The order also emphasizes that utility ownership "will require careful consideration to ensure that such a structure is in the best interest of the ratepayer and that utilities are not able to monopolize any market segment." (RPS Order, 2010)

Opinion No. 01-5 was not explicit about the logic of allowing utility-owned DG projects in the pilot. Still, almost a decade later, the April 2010 RPS Final Order is more clear concerning the circumstances under which utility ownership of DG is appropriate. The case concluded that while utility ownership of DG is not prohibited or illegal, it would be challenging for the Commission to approve "at this time." As stated in the April 2010 Order and the VMPP Statement, a utility must demonstrate that its ownership of DG provides a substantial public benefit, does not harm competition and provides measures to mitigate market power. The Order states that though not impossible, demonstrating the benefits of utility ownership relative to customer owned projects would be a challenge, particularly because there are few customer projects developed in the downstate area. Nevertheless, where utilities own DG-related equipment such as meters, inverters and controls, with the customer owning the DG resource itself (as the third form of the utility DG ownership proposed here), the benefits of DG can be recognized without requiring the demonstration of utility ownership of the resource.

## 10.1 Vertical Market Power and Unfair Competitive Advantage

Electric industry restructuring seeks to promote a competitive market for wholesale power, retail power, or both. To do so, market structures are developed to prevent the exercise of undue market power over the price or availability of power by any market participant. Two major issues arise when utilities own DG assets that do not arise when utilities own only DG-related equipment: vertical market power and possible unfair advantage over other wholesale energy or DG providers.

Vertical market power could exist if utilities own and operate generation or T&D assets (including DG) in a manner that could or does unfairly benefit their DG businesses. Utility good faith in design and implementation of markets is generally not sufficient to address vertical market power concerns. Regulators typically need to provide market power oversight of terms and conditions and market monitoring of implementation. Requiring competitive solicitation mitigates these issues, assuming proper design, and may be included in either utility ownership or customer ownership models.

Two examples of potential vertical market power are (1) a T&D company could hinder entry by generators into its own territory by delaying or imposing unrealistic interconnection requirements (PSC, 1998); (2) a T&D company could influence the transmission constraints that affect the operability or profitability of generation owned by others.

The first concern can be mitigated to a great extent by appropriate rules and standards established by the NYISO, FERC and the PSC. It is worth noting that utility DG ownership could provide an opportunity to better understand the impact of DG on the distribution system, resulting in a more standardized and efficient interconnection process and a more precise assessment of DG benefits. The second concern is likely insignificant for smaller scale CHP/DG and renewable generation for the following reasons:

(1) Renewable generation such as PV and wind is an intermittent resource whose availability is not under utility control. Therefore, there may be less incentive for a utility to use T&D constraints to raise prices than if the utility owned dispatchable generators.
(2) Because the primary goal of DG in the utility DG ownership model is to meet on-site or local demand (in the case of stationary DG units) or alleviate T&D constraints (by mobile and other types of DG), the company may have little incentive to exercise market power to influence wholesale market price by retaining transmission constraints.
(3) CHP/DG resources are small relative to the size of the wholesale markets. While the total collective DG capacity could become material eventually, limiting the purpose of DG ownership to T&D support would limit the collective size of CHP/DG fleets owned by the utility.

The second major issue arising from utility DG ownership, the perceived unfair advantage over other wholesale energy providers, stems from the utilities' rates typically being set to permit recovery of and on investments through the rate base (subject to prudence and used and useful standards). This policy could give an unfair advantage to the utility because private companies' business is not similarly protected. Private companies can be divided into two distinct groups – wholesale generators such as independent power producers (IPP) and private DG project developers.

Wholesale generators or IPPs are typically private companies without cost recovery from captive ratepayers via regulated rates. In the deregulated energy and capacity markets in New York, wholesale generators are likely to object to generation ownership by utilities. If the amount of generation owned by a distribution utility is small and limited to a particular public purpose, such as supporting T&D or promoting renewable generation, the concerns of competitive wholesale generators may be mitigated. When DG developers or aggregators of DG become more active in the wholesale markets, the presence of utilities in these businesses means a smaller share of private DG businesses in the wholesale market. Utilities would then need to be able to demonstrate that the ownership will benefit such private companies in addition to ratepayers and be subject to market power oversight and mitigation measures.

The threat of competition from utilities is a major issue affecting DG project developers that can be mitigated to a great extent by limiting utility DG ownership to a maximum capacity and location and providing market players with ample business opportunities. Further difficulties can be avoided if utilities use their own property to site DG projects, and contract out to private companies the work of engineering, procurement, and construction (EPC), as well as maintenance work.

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

Analysis of Regulatory Disincentives to Utility Ownership/
Facilitation of DG and Remedial Policies
Task #4

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# 1. REVENUE DECOUPLING MECHANISMS (RDM)

Electric distribution utilities are the primary point of contact for consumers when procuring electric energy and power. Most customers acquire their retail electric energy services either through, or from, their local utility. A distribution utility obtains its revenues from the sale of delivery service to retail customers on their systems while a vertically integrated utility obtains its revenues from the sale of electricity supply to retail customers.

Customer demands for energy services can be met via numerous sources including;

- utility-delivered electric energy and power,
- more efficient buildings, appliances, and other energy using capital equipment that reduce energy and power requirements, and
- customer sited renewable generation or other forms of clean onsite power and combined heat and power.

To the extent that a customer reduces its annual purchases of utility services, whether vertically-integrated or distribution-only, will see a reduction in its revenues. Under traditional rate making, that reduction in utility revenues will translate into lower earnings for any utility that is recovering fixed costs through its energy or delivery charge, i.e. its rate per kWh[1]. More efficient use of energy at customer sites and customer sited clean DG and CHP will reduce utility sales. Where government policy requires a reduction in electricity sales and an increase in renewable DG and clean, high efficiency CHP, there is an inherent conflict between the interests of the utility and the interests of society, as expressed in public policies.

In this section we explore issues involved in aligning the financial interest of distribution utilities with the preferences of regulators for ever greater levels of energy efficiency and clean DG CHP.

In subsection 1 we describe the impact of sales reductions on utility earnings. The traditional model for compensating utilities for the services they provide creates a linkage between incremental (decremented) sales and increased (reduced) earnings.

In subsection 2 we explore the rationale for implementing a new model for compensating the distribution utility in the form of a revenue decoupling mechanism (RDM). The RDM ostensibly breaks the linkage between utility earnings and increased sales. In theory this business model will make the utility indifferent to lower sales occurring as a result of higher levels of efficiency and deployment of more DG/CHP.

Subsection 3 poses the question of whether or not the RDM is a sufficient mechanism for meeting social goals of increasing efficiency and DG/CHP. We note that making the utility indifferent to lost revenues from DG/CHP may not be a sufficient to motivate the desired behavior.

In the final subsection we explore certain incentives that may be required in addition to establishing an RDM to meet preferences for more clean DG/CHP deployment.

## 1.1 Impact of Sales Reductions on Utility Earnings

It has long been recognized that electric utilities experience a financial disincentive when promoting energy efficiency, renewable energy or clean distributed generation and combined heat and power programs within their service territory. When a state expresses a public interest objective in promoting energy efficiency, customer owned renewable generation and efficient combined heat and power this objective is in conflict with the utilities interest in maximizing earnings.

[1] Customer reductions in purchases of utility services during a limited number of peak hours generally do not translate into lower utility earnings because of the limited reduction in kWh revenues and because the utility may be able to either avoid peak hour energy and capacity costs or recover those costs from other customers or off-system sales.

In traditional cost of service regulation, the utility finds it profitable to increase sales (or avoid a decrease in sales) in the period between rate cases, as long as the marginal revenue from the sale exceeds the marginal cost of the kWh sold. For a distribution-only utility the marginal revenue is the distribution component of the retail rate. The marginal cost is the marginal variable distribution system costs per kWh delivered to serve the next increment of load.

In traditional rate making, which applies to most vertically-integrated and distribution-only utilities, rates are established in a periodic general rate cases. Utilities are given the opportunity to recover their revenue requirements for a "test year" through rates which are a mix of customer charges ($ per customer / month), demand charges ($ per kW) and energy or delivery charges (cents/kWh).

The test year may be a historical 12-month period or a forecast 12-month period. The revenue requirement is computed for the same period as the test year, includes all of a utility's' costs of doing business, and reflects certain types of changes from the test year, the types depending on the jurisdiction. Utility costs can be broadly categorized as variable costs (e.g., fuel related costs, variable operation and maintenance costs, some types of transmission charges), fixed operation and maintenance costs, and other fixed costs such as administrative and capital costs. In the terminology of utility regulation, the rate base is total cost of utility capital net of depreciation. A utility's rates are set based on a revenue requirement that reflects its variable costs (e.g., cost of fuel and purchased power for the test year sales), plus annual depreciation of capital plant (the initial cost of the capital plant divided by its average lifetime), annual interest on corporate debt, annual preferred dividends, as well as an opportunity to earn an annual return on the capital. Earning a return on capital is necessary to continue to attract equity investors to provide financial resources for the utility to invest in physical and working capital over time, as well as to be able to issue corporate debt at reasonable rates for those purposes. The return on equity may be thought of, roughly, as the utility's allowed earnings or profit. Utilities and their investors may focus on the return on equity (ROE) per share rather than on the total absolute amount of earnings.

The rates for most utilities are set such that they recover some portion of their fixed costs through their energy or delivery charge, i.e. the rate per kWh. The result is a rate per kWh that will provide the utility an opportunity to recover its variable costs, plus some portion of its fixed costs including an allowed return on invested equity, provided that its actual kWh sales are equal to the test year sales upon which the rate was set. (This also assumes that the utility's actual variable and fixed costs are less than or equal to those assumed in its revenue requirements.)

Therefore the rate (price) of a kWh sold includes a portion to recover ROE, which permits the utility to earn a return on its equity investment. If the utility experiences higher sales, all else equal, the utility will accrue a higher ROE. Alternatively, if the utility experiences lower sales than forecast in the rate case, then all else equal, the utility will experience a lower ROE than expected. The same holds true for revenues needed to pay interest on debt and preferred dividends. The only instance when the marginal sales will not contribute to increased profit is in the case where the marginal revenue (i.e., the distribution component of the retail rate) is less than the marginal variable distribution costs per kWh required to serve that incremental increase to the load.

A portion of each kWh sale is also allocated to the return of utility capital, i.e., depreciation. The return of capital is the remuneration to a regulated distribution utility for investments made in all of the equipment necessary for providing electric service, including T&D facilities, vehicles, control equipment, buildings and, if vertically integrated, generation plant. If these investments were "prudently made" and are "used and useful," the associated depreciation expense (and the corresponding portion of the above return) is allowed in the utility's revenue requirement and is reflected in its rates.

Energy efficiency investments providing electric energy services that function as a substitute for utility owned ("supply side") investments impinge upon the expansion of utility revenues and earnings in another sense. Providing electric utility services from regulated supply side sources requires the deployment of utility-owned capital. Utility fixed assets earn a rate of return. As noted above the regulator includes in retail rates what it deems a fair return on equity (or debt). In contrast to an unregulated business entity, a distribution utility (or a vertically integrated utility) can rely on its monopoly customer franchise as a source of revenue for its allowed costs, a much less risky situation than that of an unregulated business.

On the other hand, electric utility services from energy efficiency investments at customer premises do not employ utility capital. If the utility operates programs that encourage energy efficiency investments at customer premises they are in effect diminishing the size of their franchise. Wherever non-utility owned, demand side resources are employed as a substitute for providing electricity services that might have been provided by utility owned, supply side resources, there is a diminution of the potential size of the utility investment for that area. The service is being provided but the utility does not own the assets providing the service.

Capital used to deliver electric power earns a return. When the same service is provided via energy efficiency savings, there is no return to the utility, other than covering the costs incurred in providing the efficiency services. All else equal, from the utilities perspective providing energy services via energy efficiency is not nearly as profitable as providing services via delivery of electric power to end use customers. Similar observations apply to services provided by DER to the extent that they avoid or defer T&D investment. To the extent that a utility is or expects to be in a position to make additional investments on advantageous terms, this is a concern to the utility.

The two points can be summarized as follows. Under traditional electric utility regulation fostering reductions in energy use is at cross purposes with the utility's interest in:

1. maximizing its profit between rate cases, and
2. expanding the size of its asset base, thereby enhancing its revenue generating potential

As long as the marginal revenue ("MR", or the distribution portion of the retail rate) from the sale of an additional kWh exceeds the marginal cost ("MC", as noted above, largely comprised of marginal distribution system costs of serving the next increment of load) of supplying that kWh, the utility will increase its earnings by virtue of that sale or avoiding a reduction in sales. Electric distribution utilities are a very capital intensive business. It is generally the case that MR > MC, making an increase in sales profitable for the company, and consequently implying that a decrease in sales diminishes utility profitability.

## 1.2 Revenue Decoupling Mechanisms (RDM)

Several states that have expressed a public interest objective in expanding the provision of electric energy services via efficiency, distributed generation and demand response have at the same time called for an alternative ratemaking strategy that would facilitate this objective. Decoupling mechanisms are said to serve this purpose by creating an alternative regulatory design that removes the disincentives that the utility faces when there is a compelling justification for providing an increasing share of electric energy services via demand side, or efficiency resources.

With utility earnings linked to increased sales the utility has a potential disincentive to promote cost-effective energy efficiency investments at commercial, industrial and residential customer sites within their service territory. When efficiency investments are the least cost means for providing incremental energy services, this disincentive with respect to efficiency investments may create a conflict between the interests of the ratepayers within the service territory and the distribution company serving those customers.

The New York State Public Service Commission (NY PSC) found in Case 03-E-0640 that properly designed revenue decoupling mechanisms were needed to address potential disincentives to utilities promoting and implementing more efficient energy use.[2] RDM has been proposed by the NY PSC as a mechanism to align the interests of the supplier of electric energy services (the distribution utility) with the consumer of those services, the electric ratepayer within that company's service territory.

On April 17, 2007, the New York State Public Service Commission ("Commission") announced its support for utility revenue decoupling mechanisms[3]. In 2003 the Commission had initiated a proceeding to investigate potential

[2] See Commission Order Requiring Proposals for Revenue Decoupling Mechanisms. Issued and Effective April 20, 2007. Case 03-E-0640. information accessed at http://www.dps.state.ny.us/Case_03-E-0640.htm
[3] "PSC SEEKS MORE EFFICIENT ENERGY USE: -Utility Revenue Decoupling Mechanisms to Eliminate Disincentives-" Cases 03-E-0640;06-G-0746. April 18, 2007

disincentives in the current rate structures that impeded the promotion of energy efficiency; customer sited renewable technologies and other forms of distributed generation. In July of 2006, the Commission expanded this proceeding to encompass the state's gas utilities. A final Commission Order was issued and effective on April 20, 2007.

Based upon its review of the evidence presented the Commission found that current rate designs were acting at cross purposes with an overall state objective to encourage greater customer adoption of existing and developing technologies for the clean production and end-use of energy. As a consequence, the Commission directed the utilities to file revenue decoupling proposals in any ongoing and all newly initiated rate cases.

Commission Chairwoman Acampora made this statement in support of broad based decoupling mechanisms.

> "To the extent current design of utility delivery rates continue to link the recovery of utility fixed costs, including earnings, to the volume of actual sales, disincentives exist that limit the utilities' interest in promoting efficient energy use," said Commission Chairwoman Patricia L. Acampora. "Creating a mechanism to reduce or eliminate the dependence of utilities' revenues on sales, would thereby increase the utilities' interest in the promotion of customer initiated more efficient energy use. The resulting public benefits from new energy efficiency programs, renewable technologies and distributed generation could be substantial." [4]

The Commission approved implementation of a broad based decoupling approach, rather than the more limited Lost Revenue Adjustment Mechanism (LRAM) method. An LRAM attempts to true up estimated lost revenues attributable to a program or a suite of programs. The more broad based approach approved by the Commission required the utilities to submit mechanisms that would true up forecast and actual delivery service revenues. This approach is significantly more far reaching than a net lost revenue adjustment that focuses on identifiable losses from specific energy saving programs. It avoids complex debates over what lost revenues are attributable to energy efficiency programs and it practically eliminates a utility's incentive to oppose energy appliance standards and other state and federal measures that might reduce utility sales.

RDM has been identified as a mechanism for effectively breaking the link between utility annual sales and utility recovery of fixed costs and earnings.

In its broadest form, the RDM adjusts rates up, or down, outside of a general rate case. The RDM adjusts rates so the utility's actual annual revenues remain sufficient to cover the fixed cost portion (including ROE) of the utility's revenue requirement approved in its last rate case. For example, if revenues from sales fall short of the amount required to recover these fixed costs, the rate is adjusted upward to collect the difference. If revenues exceed the amount required to recover fixed costs, rates are reduced to return the difference to ratepayers. Put another way, by maintaining the recovery of fixed costs, RDM avoids increases or decreases to ex ante profitability.

There are many nuances involved in the design and execution of an RDM. The overarching objective is to create a regulatory mechanism that does not penalize utilities for reductions in delivered energy sales, when sales reductions are a state and social goal.

Some of the nuances in RDM design have to do with the extent of the protection that the utility receives. For example, RDM can be designed to shift business risks from the utility to the consumer. For example, sales fluctuation due to weather patterns is a risk (and reward) traditionally borne by the utility. If a summer is cooler than normal or the winter warmer than normal, then utility sales will likely fall significantly short of forecasts resulting in reduced earnings. On the other hand, if a summer is hotter than normal or a winter colder than normal, then utility sales will likely rise significantly above forecasts, resulting in increased earnings. Likewise, if economic conditions embedded in a sales forecast were overly optimistic and realized economic activity falls short of the forecast, then utility revenues and targeted rate of return will not be realized. If economic conditions embedded in a sales forecast were overly pessimistic and realized economic activity exceeds the forecast, then utility revenues and targeted rate of return would be greater than expected. RDMs can be designed to address this shifting of weather risks and other economic development risk.

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[4] ibid, page 1

Other issues of concern are the extent to which the utility is made whole for divergences from projected sales. At one end of the spectrum is the more limited Lost Revenue Adjustment Mechanism (LRAM). In this approach rate adjustments are limited to truing up for sales reductions that are demonstrably a consequence of utility-run programs designed to lower sales. At the other end of the spectrum is the full true up of actual to forecast sales. In this instance, there is no need to determine how the sales reductions occurred. Reductions may be due to codes, standards, naturally occurring efficiency gains, or any other source. Supporters of the more broad based approach note that this approach has lower oversight and compliance costs, is less subject to gaming and it does not penalize the utility for sales reductions due to building codes and higher efficiency standards. The supporters point to the fact that in many instances utilities have opposed tighter codes and standards.

## 1.3 Decoupling Mechanisms Do Not Fully Address Utility Concerns with CHP Development

A broad based RDM removes the explicit disincentive created by the lost revenues that occur with the removal of that portion of the customer load once served by the distribution utility. Still, it fails to address numerous other issues that may affect the operations and the future profitability of a distribution utility.

### 1.3.1 Impact of RDM on Utility Perspective on CHP

New CHP projects should benefit at the margin from the institution of full decoupling mechanisms. A full decoupling mechanism is one that "true ups" forecast and actual delivery service revenues. This is the type of approach that the Commission approved in its April 20, 2007 Order.

The type of broad based decoupling prescribed by the Commission removes one major obstacle to the development of CHP within electric distribution utility service areas. It may be seen as a necessary, but not sufficient policy approach for facilitating the more rapid deployment of economically viable, environmentally preferred customer-owned CHP[5].

### 1.3.2 Remaining Barriers to utility support for CHP

Customer side, CHP is a substitute for the power delivery services of the distribution utility. When customers remove a significant portion of their energy and capacity demand from the distribution system, for 4,000 to 8,000 hours per year, they are at the margin shrinking the size of the utilities franchise. Even with compensation for the loss of revenues the utility continues to be worse off with increasing levels of CHP as it lowers the future earnings potential of its franchise. The worth of a corporation is the discounted future value of its earnings. Increasing levels of CHP reduce the future earnings potential of the enterprise by shrinking the scale of operation.

Above and beyond RDM, utilities will likely require incentives in order to meet accelerated resource acquisition targets. States interested in markedly increasing the rate of distributed energy resource growth have recently paid greater attention to a portfolio of measures that would better align the distribution utilities interests with those of policy makers and ratepayers. This portfolio of incentives is likely to include RDM as well as incentives that provide the utility with a higher profit upon meeting certain agreed upon targets.

There are several reasons why simply breaking the link between sales and earnings is likely to be an insufficient incentive to change the rate of growth of DER investments in a really meaningful way. We explore several of these reasons in this section.

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[5] Such sites may be customer or third party owned and/or operated. The key distinction creating additional electric distribution utility disincentives is attributable to the fact that the utility has no ownership stake.

### 1.3.3 DG CHP Capital May Be Less Profitable to a Utility than Utility-Owned Capital

This research study is focused on examining the possibilities of DG/CHP as an alternative to utility distribution capital investment. From society's perspective we can envision many plausible situations where a DG CHP or DER solution could provide a substitute for utility capital investment in the distribution system and do so at a lower cost to ratepayers. Nevertheless, from the utility's perspective instances of this sort may represent a loss in future earnings potential. RDM breaks the link between sales and earnings but it does not break the link between rate-base and future earnings potential. Under the current system of utility cost recovery, increasing the rate of substitution of DG/CHP assets in place of new utility investment means an increase in the diminution of the utility's franchise. This issue will be explored in more detail in the next section as we examine rate-basing utility investments in DG/CHP.

In contrast to the above argument we note there are some instances that DG/CHP projects are viable alternatives to T&D projects and may be seen by the utility as in the best interest of investors. For example, when T&D projects face obstacles, such as delay in project schedules due to environmental concerns, local opposition, and so on, DG/CHP and DSM could be beneficial to maintaining reliability of the electric system. In other instances a utility may be capital constrained and could welcome a solution that does not require them to raise additional capital – particularly when the environment for project financing is difficult.

### 1.3.4 Distribution System Planners are not Trained to Identify DG CHP Solutions

Using DG/CHP assets in distribution system planning has not traditionally been part of the operations of distribution utilities. There is an inertia that exists in the form of years of education and training in supply side methods. The existing tools familiar to distribution system planners are not designed to capture DER solutions. There is an existing investment in simulation models, routines and staff planning, design and operation experience that has to be redirected in order to fully take advantage of DG/CHP system solutions.

The retraining of staff and the retooling of existing methods and procedures is not costless. A change of business practice requires investment. Unless the utility is specifically compensated for this retraining of their human capital assets they will likely view such changes skeptically.

In this section we have underscored the point that there are some very pragmatic reasons why the distribution utility would be averse to substituting DER resources for traditional capital expenditures in the T&D system.

### 1.3.5 DG CHP Resource Acquisition is not the Utility's Core Business

Discovering DG CHP assets to substitute for distribution system capital investments is a time consuming process requiring the employment of the utility's human capital resources as well as specialized assessments requiring modeling and analysis tools. This is not a costless exercise. In our conversations with affected parties we have heard that one of the major issues with utility DG/CHP developer relationships is timeliness and responsiveness. From a development standpoint delays in a project's timetable and uncertainties in project costs can be fatal. From the utility's perspective, making time to review and respond to developer requests takes time away from other activities. There may also be conflicts in system resource decisions between the needs of the DG/CHP developer and the utility's assessment of what is optimal. A case in point is the "red zones" in the Con Edison service territory. There are a number of areas within New York City where DG/CHP deployment is severely curtailed unless and until Con Edison makes necessary system upgrades. The schedule of upgrades that Con Edison has set forth has been criticized by some as being a hindrance to the development of viable and socially beneficial DG/CHP investments.

### 1.3.6 Risks Inherent in Lack of Control over the Assets

When a DG/CHP solution is put in place in lieu of a traditional utility capital investment, the utility still shoulders the responsibility for insuring the reliability of the system. When the ownership and operation of the asset shifts from the control of the utility to the control of an external party, the utility is bearing an increased risk. The primary focus of the utility is on the provision of safe and reliable service. Utilities are penalized for loss of service and for lapses in service quality. Utilities have expressed concerns regarding these types of issues that arise when ownership and control of the asset is taken out of their hands:

- Guarantees that the DG/CHP will run when required
- The ability to run the DG/CHP asset in a manner that optimizes the utilities needs
- Information on the assets likely performance
- Control over the maintenance schedule

These issues are not insolvable. Some can be addressed by legal contracts. Still, the point remains that when the responsibility remains with the utility, but the asset is removed from their control, a greater level of risk is borne by the utility. In the final section we examine the prospect of utility ownership, which is also a solution to this problem. Nevertheless, utility ownership of distributed energy resources (DER) has consequences that must be considered in the broader context of promoting efficiency, competition and innovation.

## 1.4 Utilities may Require Incentives to Support Accelerated CHP Development

States interested in markedly increasing the rate of distributed energy resource growth have recently paid greater attention to a portfolio of measures that would better align the distribution utilities interests with those of policy makers and ratepayers. This portfolio of measures is likely to include RDM as well as incentives that provide the utility with a higher profit upon meeting certain agreed upon targets.

These additional incentive measures include the following:

i. cash rewards for achieving and exceeding savings goals, often stated as a percentage of savings
ii. incentive payments based on kW of DER assets installed in a performance period (e.g. $150/kW for all DG operational in a calendar year)
iii. capturing a percentage of savings of the DER investment as compared with utility investment (e.g. utility investment cost is $550/kW , DER solution is paid $400/kW, utility keeps $150/kW)
iv. rate-basing and return on eligible customer Utility Ownership of the DG Resource

Proponents of RDM as well as affected DG stakeholders agree that one or more incentives in addition to an RDM are required to reach significantly higher levels of clean DG penetration. As noted in the chapters above, simply breaking the direct link between increasing sales and increases in earnings is not a sufficient condition for encouraging greater levels of DG penetration on the existing utility distribution systems.

### 1.4.1 Incentive Payments Based on Installed Capacity in a Performance Period

In order to stimulate greater utility interest in DG/CHP some regulators have put in place an installed capacity incentive for the utility. For example the State of Connecticut in June 2005 passed legislation (Senate Bill 7501) that provided incentives for utilities to facilitate the installation of distributed generation (including CHP) within their service territories. Under the legislation, a utility would receive an incentive payment to "educate, assist, and promote investments in customer-side distributed resources developed in such company's service territory." When implemented in 2006, the size of the incentive payment was $200 per kilowatt. Each year thereafter, the incentive decreases by $50 per kilowatt until 2010, when the incentive payment becomes $50 per kilowatt. The payment is made at the time the resource becomes operational.

If utilities, their regulators, and affected parties identify cost saving DG/CHP investments on the distribution system, the utility could capture a reward in the form of retained savings. Such a reward structure might direct the utility towards identifying the highest value DG/CHP resource solutions. For example, suppose a fixed payment of $300/Kw-year was set on DG CHP investments that are deemed a substitute for a proposed utility investment. If this were the case, avoided utility distribution system costs of $600/Kw-year would net the utility a $300/kW-year bonus; similarly avoided distribution system costs of $400/Kw-year would net the utility a $100/kW-year bonus.

The non-participating ratepayer does NOT receive a benefit in this scenario as all of the gains are split between the utility and the DG/CHP owner. Nevertheless, as long as avoided costs are accurately characterized and the DG/CHP solution does not increase costs over the utility investment case, then the non participating ratepayer is no worse off.

### 1.4.2 Permitting Utilities to Rate-base and Earn a Return on DG CHP Investments

If a utility has the choice of addressing a T&D investment with two equally effective measures, and if one measure is utility owned and the other owned by an external party, the utility owned measure will tend to be preferred by the utility, at least in those situations where it has ready access to capital. With utility ownership comes the right to rate-base the measure earning a return of the original capital investment and return on the equity portion of the investment (profit). A measure sited at a customer facility and paid for by the customer or a third party developer produces no expansion of the capital base of the utility. Over time, as customer sited T&D assets substitute for utility assets, the capital base and subsequently the earning power, of the utility is smaller than it would otherwise have been.

This is an important disincentive that RDM alone does nothing to address. The future earning power of the utility is linked to the size of its asset base. A DG/CHP program as a substitute for T&D capital investment inevitably leads to a smaller asset base then the status quo without such a program.

On the other hand, scenarios clearly exist where the utility would prefer not to invest its own capital for a variety of reasons. It may be that capital solution proposed by the utility is more costly in terms of time, effort and public image than would be the DG/CHP solution. In dense urban areas for example, utility construction may meet with public opposition, may be delayed for long periods in the codes siting and permitting process, and otherwise be subject to other unforeseen costs and disruptions. Likewise, if the utility is capital constrained, if the cost of capital is high and availability of capital tight, the utility may prefer a customer based DG/CHP solution.

The issue of ownership is a complex one. If the distribution utility is permitted to own the DG/CHP resource many of their stated concerns, such as asset control, dispatchability, or asset reliability, are all greatly diminished, if not eliminated.[6] The utilities have expressed a concern that in the absence of physical control over the resource, they will be at risk that the DG/CHP owner may choose not to run when needed, for whatever reason. The asset may not run for an economic reason, or as an operational decision, or for any number of reasons that are germane to the end-use customer. Another concern that has been voiced is dispatchability. The way in which an end user might run the system at a particular time may not be the optimal manner in which the utility would run the asset, were the asset under the utility's control. The issue of maintenance and reliability has been put forward as a concern. The utility asserts that they take on some risk in not knowing the reliability of the asset. Were the asset under its control they would have full information regarding the schedule of maintenance and the expected performance of the asset under various operating conditions.

There may be some information gains to be had by allowing the utility to own the DG/CHP resource that is serving as a substitute for distribution capital investment. Lack of information and lack of control raises the performance risk for the utility. Ownership greatly diminishes the risk. It does so at a potential cost to those who compete with the utility by offering DG/CHP project development services. As a regulated entity with access to system and customer information that others do not possess, the utility has a dominant position in the marketplace. This position of dominance might be used to undermine real competition in the provision of DG/CHP services. The loss to society in this case is one that is hard to quantify, but may nonetheless be quite real and possibly substantial. There is a risk that if the market is captured by a dominant player, costs may be driven up due to a lack of real competition while innovation, product and service quality may suffer.

[6] A case in point is Detroit Edison. As discussed in Section 1, Detroit Edison has been aggressively purposing utility owned mobile DG units to solve a number of distribution problems.

## Summary

In this task we have reviewed the rationale for instituting a revenue decoupling mechanism. The RDM is designed to break the link between sales and earnings. This linkage is a clear disincentive to the utility that is required or who chooses to promote programs such as energy efficiency and DG/CHP (collectively "DER") that involves a loss of utility sales.

The RDM removes a disincentive but does not create an incentive for the utility to acquire DER assets. Policy makers are expecting DG/CHP and other DER assets to play a markedly expanded role in the future energy system in New York. In order to meet these goals the rate of increase of DER resource acquisition will have to accelerate.

For a variety of reasons explained in the sections above, RDM alone is not likely a sufficient mechanism to create a rapid acceleration of DG/CHP deployment. There are disincentives that remain even with the implementation of an RDM. These disincentives include but are not limited to the following:

- DG/CHP capital may be less profitable to the utility than utility-owned capital
- Distribution system planners are not trained to identify DG/CHP solutions
- Systems planning and analysis software and methods and procedures typically do not consider DG/ CHP solutions
- Risks inherent in lack of control over the assets, and
- DG/CHP resource acquisition is not the utility's core business

It appears that incentives in addition to RDM will be required in order to encourage distribution utilities to capture the benefits; including the potential T&D avoided cost benefits, of DG/CHP in their service territories. Proponents of RDM as well as affected DG/CHP stakeholders agree that a suite of incentives, in addition to an RDM, will be required to reach significantly higher levels of clean DG/CHP penetration.

# 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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# 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]

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[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

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[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*. |

[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]<br>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

[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.

[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:

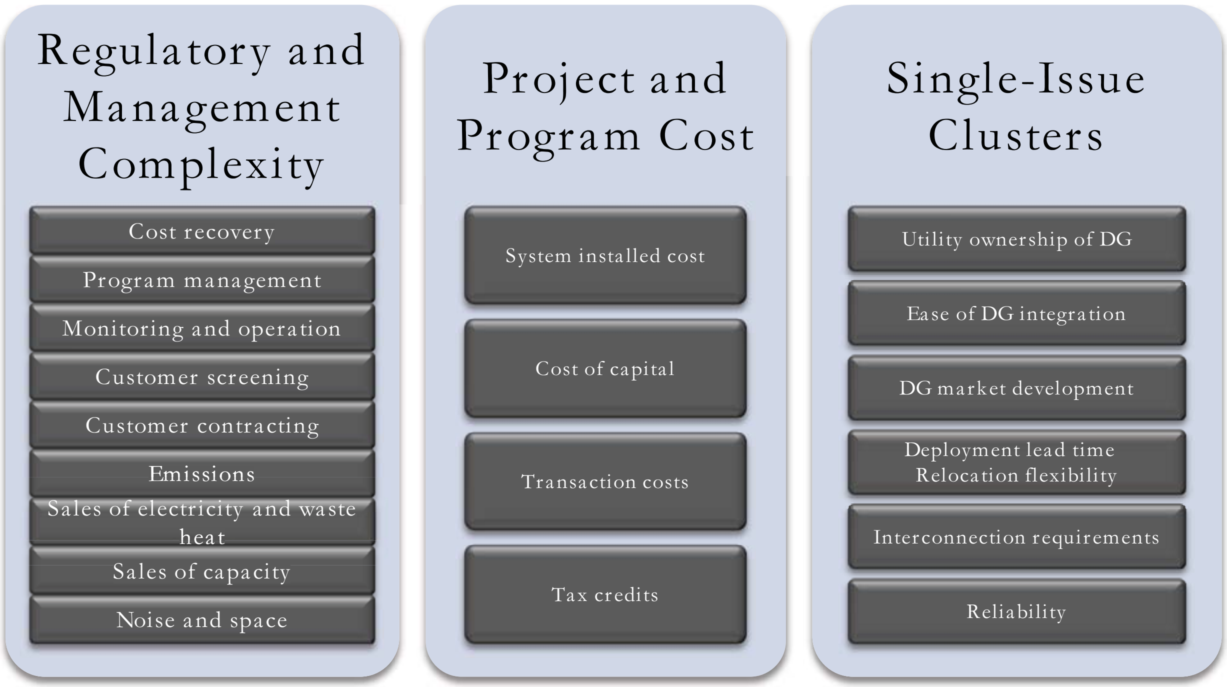


**Figure 1 – Summary of Overarching Issue Clusters Identified in Task 3**

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

Final Report No. 11-23

**State of New York**
Andrew M. Cuomo, Governor

**New York State Energy Research and Development Authority**
Francis J. Murray, Jr., President and CEO