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

New York State Energy Research and Development Authority

Albany, NY
nyserda.ny.gov

Mark Torpey
Senior Project Manager

Prepared by:

Pace Energy and Climate Center
Tom Bourgeois
Project Manager

and

Dana Hall

Synapse Energy Economics, Inc.
Kenji Takahashi
William Steinhurst

NYSERDA Report 11-23 | NYSERDA 10472 | February 2011

NOTICE

TABLE OF CONTENTS

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.

---

[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 $33/kW-yr[7] to $110 kW-yr[8] $66/kW-yr
Avoided Electricity Generation	$63.32/MWh[9] $87.79/MWh[10] $38.65/kW[11] $55.51/kW[12] $67.64[13] $117.92[14]
DRIPE	$11.51/MWh $600/kW-yr[15] $180/kW-yr[16]
Ancillary	.5-1.5 cents/kWh[17] .2 cents/kWh 0 cents/kWh .3 cents/kWh
Backup Reliability Value	$100/kW 0 – 2.7 cents/kWh[18] $20/MWh[19] $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 28-45% reduction in reactive power consumption $450/kW reduction (see ____Study)
Avoided T&D Costs (estimated from PJM, See ORNL, Hadley 2003)	$150/kW 35% coal energy displaced w/ DER 52% coal energy displaced w/ DG Average marginal cost of power displaced by DER supply 2.99 ¢/kWh Average marginal cost of the power displaced by the DG strategy was 2.62 ¢/kWh for baseload 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 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 Discount factor .96 $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

---

[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]

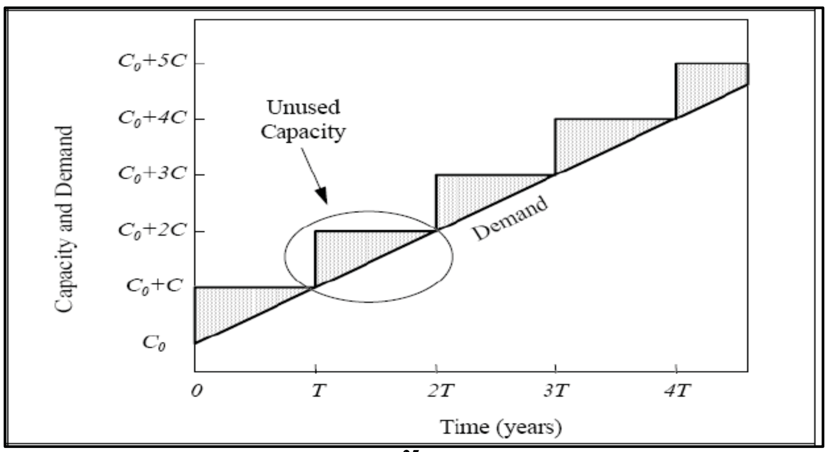

Figure 2.1: Capacity and Demand [25]

[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.

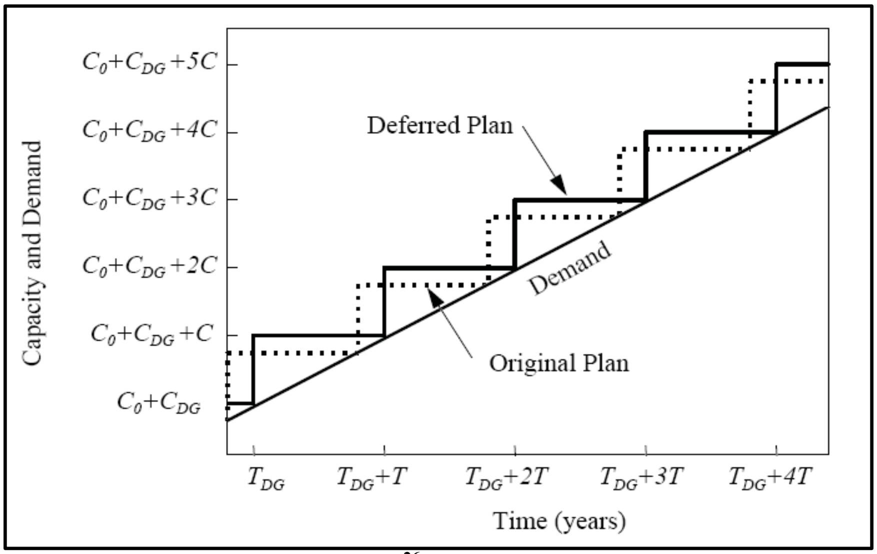

Figure 2.2: Capacity and Demand [26]

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.

<u>Congestion</u>: 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.

<u>Time of operation</u>: 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]

---

[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.

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:

---

[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]

---

[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.

---

[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.

---

[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]

Optimal Energy Study

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.

---

[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:

NYSERDA 2005 Study[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:

---

[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

<u>Green House Gas Emissions Reductions</u>
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.

---

[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.

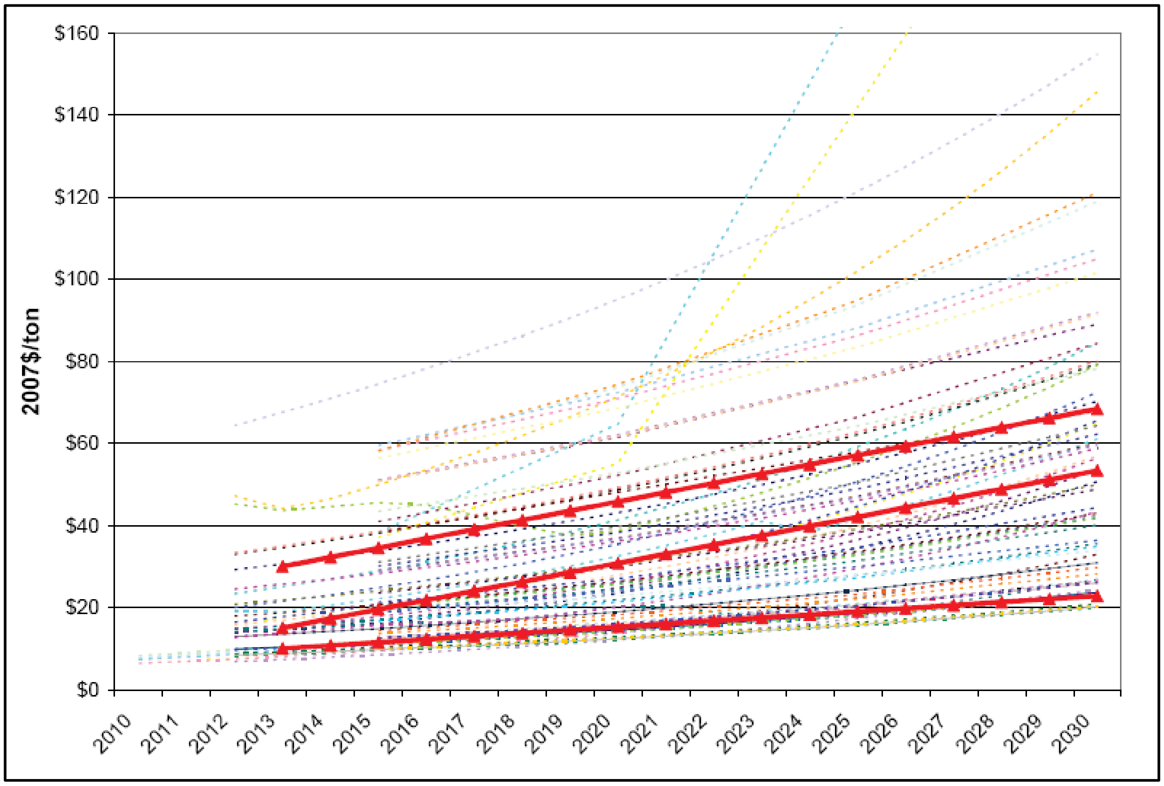

Figure 2.3.7: Synapse 2008 CO_2 Price Forecasts vs. CO_2 Prices Used by Regulatory Commissions and Utilities in Resource Planning Analyses (2013-2030, in 2007 dollars)

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

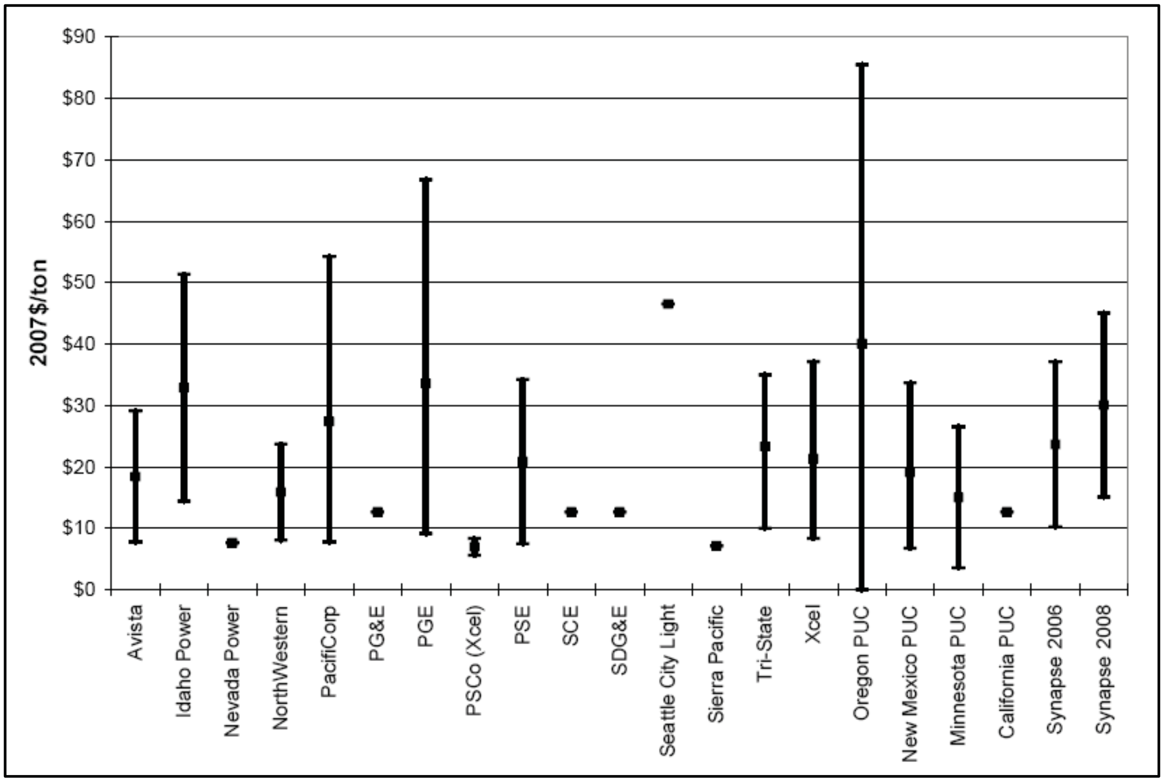

Table 2.3.7: Synapse 2008 CO_2 Price Forecasts vs. Results of Modeling Analyses Major Bills in Current U.S. Congress – Annual CO_2 Prices (in 2007 dollars)

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.

---

[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](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)

---

[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 (90th percentile) is a net 0.9 cents/kWh (xx cents/kWh in $2008), and the low end of the range (10th 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.

---

[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

[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*.]

---

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

Americans for Solar Power. *Build-Up of PV Value in California – Methodology*, 2005.

Armory Lovins, et al. *Small is Profitable*. Rocky Mountain Institute, 2002.

Asgeirsson, H., R. Seguin. *DG Comes to Detroit Edison*. Transmission and Distribution World, Oct. 1, 2002. Available at http://tdworld.com/mag/power_dg_comes_detroit/

Bourgeois, T, A. Greene, D. Rosenblum, C. Young. *Guidebook for Small Combined Heat and Power Systems Seeking to Obtain Emissions Reduction Credits in New York State*. NYSERDA, 2006.

Bourgeois, T, A. Greene, D. Rosenblum, C. Young. *Emission Allowance Market Opportunities for Small Combined Heat Power Projects in New York State.* NYSERDA, 2006.

California Public Utilities Commission (CPUC). *Decision 03-02-068 in Rulemaking 99-10-02*, February 27, 2003.

Chernick, Paul. *Direct Testimony of Paul Chernick of Resource Inslight on Case No. 08-E-0539*, Before New York DPS on September 8, 2008.

Con Edison. *Request for Proposals to Provide Demand Side Management to Provide Transmission and Distribution System Load Relief and to Reduce Generation Capacity Requirements*. ConEd, 2007. Available at http://www.coned.com/sales/business/targetedRFP2007.asp

Contreras, J.L, L. Frantzis, S. Blazewicz, D. Pinault, and H. Sawyer. *Photovoltaics Value Analysis*. Navigant Consulting Inc., NREL/SR-581-42303, 2008.

Dossey, Tom. *Key Elements of SCE's Proposed Key Elements of SCE's Proposed Distributed Generation RFP Distributed Generation RFP*. Presented at a meeting of E2I Collaborative Pilot Program, 2004.

Eilperin, J. *EPA Presses Obama To Regulate Warming Under Clean Air Act*, Washington Post March 24, 2009.

Electric Power Research Institute (EPRI). *Economic Costs and Benefits of Distributed Energy Resources*, 2004.

Electric Power Research Institute (EPRI). *Creating Incentives for Electricity Providers to Integrate Distributed Energy Resources: A Report of the EPRI Distributed Energy Resources Public/Private Partnership*. 2007.

Electric Power Research Institute (EPRI). *Case Studies and Methodologies for Using Distributed Energy Resources for Transmission and Distribution Support Applications: An EPRI White Paper* 1010517 Technical Update, 2005.

Energy and Environmental Analysis, Inc., *Natural Gas Impacts of Increased CHP*. Submitted to US Combined Heat and Power Association, 2003.

Energy and Environmental Economics, Inc. (E3). *Renewable Distributed Generation Assessment: Sacramento Municipal Utility District Case Study*. California Energy Commission, 2005.

Energy and Environmental Economics, Inc. (E3) and Rocky Mountain Institute (RMI). *Methodology And Forecast Of Long Term Avoided Costs For The Evaluation of California Energy Efficiency Programs.* Prepared for California Utilities Commission: 2004.

Energy and Environmental Economics, Inc. (E3) and Bonneville Power Administration (BPA). *Olympic Peninsula Study Of Non-Wires Solutions to The 500 Kv Transmission Line From Olympia To Shelton and A Transformer Addition At Shelton*. 2004.

Energy Information Administration (EIA) *Annual Energy Outlook 2009 Early Release Overview*. Available at: http://www.eia.doe.gov/oiaf/aeo/index.html?featureclicked=1&

Energy Information Administration (EIA) *Renewable Energy Trends in Consumption and Electricity, 2006 Edition*. Available at: http://www.eia.doe.gov/cneaf/solar.renewables/page/trends/rentrends.html

Energy Nexus Group/ Onsite Energy/ Pace Energy Project. *Combined Heat and Power Market Potential For New York State*. Prepared for NYSERDA, 2002.

Hadley, S.W., J.W. Van Dyke, W.P. Poore, III, T.K. Stovall. *Quantitative Assessment of Distributed Energy Resource Benefits*. Oak Ridge National Lab (ORNL), 2003.

Hammerstrom, D.J., et al. *Pacific Northwest GridWiseTM Testbed Demonstration Projects:Part I. Opympic Peninsular Project*. Pacific Northwest National Laboratory, Prepared for U.S. DOE, 2007.

Hoff, T. E., H. Wenger, B. Farmer. *Distributed Generation: An Alternative to Electric Utility Investment in System Capacity*. Energy Policy. Vol. 24., 1996.

Hoff, T.E., Perez, R., Margolis, R.M. *Increasing the Value of Customer-Owned PV Systems Using Batteries*, 2004.

Hoff, T.E., Perez, R., Braun, G., Kuhn, M., Norris, B., *The Value of Distributed Photovoltaics to Austin Energy and the City of Austin*, Clean Power Research LLC, 2006.

Hoff, T.E., Perez, R., Braun, Margolis, R.M., *Maximizing the Value of Customer-Sited PV Systems Using Storage and Controls*, 2005.

ICF Consulting. *Avoided Energy Supply Costs in New England,* A Report Prepared for Avoided-Energy-Supply-Component (AESC) Study Group, 2005.

Jakubiak, Ed, Hawk Asgeirsson. *DG Comes to Detroit Edison*. Detroit Edison Energy, 2003.

Kingston, T., T. Stovall and J. Kelly. *Exploring Distributed Energy Alternatives to Electrical Distribution Grid Expansion in Southern California Edison Service Territory*. ORNL/TM-2005/109., 2005.

National Association of Regulatory Utility Commissions (NARUC). *Electric Utility Cost Allocation Manual*, 1992.

Navigant Consulting, Inc. *Distributed Generation and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative*. MTC, 2006.

NYSERDA. ***New York Energy $mart**[sm] Program: Evaluation and Status Report Year Ending Dec. 31, 2007*. NYSERDA, NY DPS, NY PSC, 2008.

NYSERDA. ***New York Energy $mart**[sm] Program Cost-Effectiveness Assessment*, June 2005.

Oppenheim, Jerrold, Theo MacGregor. *Time for Action: Tackling Energy Poverty in Canada Through Energy Efficiency, Green Communities Canada*. Democracy and Regulation, 2008.

Optimal Energy, Inc. et al. *Economic Energy Efficiency Potential New York Service Territory*. Prepared for Orange & Rockland Utilities, 2008.

Pace Energy Project and Synapse Energy Economics, Inc. *A Comprehensive Process Evaluation of Early Experience Under New York's Pilot Program for Integration of DG in Utility System Planning*. New York State Energy Research and Development Authority (NYSERDA) Final Report 06-11, 2006.

Pacific Gas and Electric Company (PG&E). *Distributed Generation and Distributed Energy Resources OIR: DG Cost Benefit Analysis under Rulemaking No. 04-03-017*. Submitted to CPUC on October 4, 2004.

Petrill, E., D. Thimsen, S. Price, J. Nimmons, J. Torpey, and R. Weston. *Creating Incentives for Electricity Providers to Integrate Distributed Energy Resources.* EPRI, CEC-500-02-014, 2007.

Rocky Mountain Institute (RMI), Energy and Environmental Economics, Inc. (E3), and Freeman, Sullivan & Co. *Marshfield Pilot Design Report, Sponsored by NSTAR Electric & Gas Corporation and Massachusetts Technology Collaborative*. 2008.

Schlissel, D., L. Johnston, B. Biewald, D. White, E. Hausman, C. James, J. Fisher. *CO_2 Price Forecasts,* Synapse Energy Economics, Inc. 2008.

Shirley, Wayne, R. Cowart, R. Sedano, F. Weston, C. Harrington, D. Moskovitz. *Distribution System Cost Methodologies for Distributed Generation*. The Regulatory Assistance Project (RAP), 2001.

Shlatz, Eugene and Steven Tobias. *The Rise of Distributed Energy Resources: Calling on the Lilliputians*. Public Utilities Fortnightly, 2007.

Smellof E., *Quantifying the Benefits of Solar Power for California*, 2005.

U.S. Department of Energy. *The Potential Benefits Of Distributed Generation And Rate-Related Issues That May Impede Their Expansion: A Study Pursuant To Section 1817 Of The Energy Policy Act Of 2005*. 2007.

Weinberg, Carl J., Joseph J. Iannucci, Melissa L. Reading. *The Distributed Utility Technology, Customer and Public Policy Changes Shaping the Electrical Utility of Tomorrow*. Energy Systems and Policy, Vol. 15, 1991.

Wiser, R., M. Bolinger, M. St. Clair. *Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency*. U.S. Department of Energy. LBNL-26756, 2005.

Wiser, R. Mills, A., Barbose, G., Golove, W., *The Impact of Retail Rate Structures on the Economics of Commercial Photovoltaic Systems in California.* LBNL, 2007.