The Influence of Distributed Energy Resources on the Hourly Clearing Price of Electricity in a Restructured Market

Dragoljub Kosanovic and Lawrence Ambs, University of Massachusetts, Amherst
Christopher Beebe, Keyspan Energy

ABSTRACT

Although Combined Heat and Power (CHP) is recognized for its energy-saving, environmental, and economic benefits, no one has developed a method of calculating non-energy-related benefits –such as transmission, distribution, and emissions - or determined who would benefit and to what extent.

This study attempts to do that by exploring congestion and associated transmission constraints in the Northeast/Boston Massachusetts (NEMA) zone of the ISO-NE region. The study was successful in that it provided limited answers to these questions, but could not provide the level of detail desired because significant information was unavailable. Here we note only the absence of the following information, which is critical to understanding wholesale power market operation:

- Transmission Line Capacity
- Transmission Line ID numbers
- Verification of Node ID Numbers With Location
- Substation Capacities and Installed Loads

Without this information, the study finds benefits associated with deployment of DG/CHP, but cannot accurately determine the amount of DG/CHP required to provide those benefits and prevent line constraints. Other missing information that would be useful is:

- Cost and location of planned transmission and distribution upgrades for the larger utilities, which permit assessment of distribution deferment values
- More complete congestion data, which would offer better guidance on DG/CHP siting, and better assess DG/CHP's ability to decrease the congestion component of the locational marginal price (LMP)

Despite the absence of this information, we believe even our limited results indicate that DG/CHP provides an important societal benefit because it can reduce LMP; reduce congestion; defer network upgrades.

Study Results

The goal of the study was to evaluate benefits and costs associated with a distributed generation unit from the perspectives of the customer, utility providers, and society. A second goal was to identify and quantify the network nodes most likely to be congested, and to determine appropriate locations and sizes for DG/CHP systems that could relieve congestion.

First, we looked at the overall potential of DG/CHP units to affect prices in the ISO-NE market. We compared the U.S. Department of Energy's inventory of "Non-Utility Power Generators by State" (US DOE 2002) to the list of generators registered in the ISO-NE bidding pool, and found 1,460 MW of generating capacity in the six states, as Table 1 illustrates.

Table 1: DG Units and Capacity by State (DOE 2002)

	Number of DG Generators			Total Generators	Total Capacity (MW)	Total Capacity for DG < 5 MW (MW)
	DG < 5 MW	5 < DG < 20 MW	20 < DG < 50 MW			
Connecticut	24	5	3	32	224	40
Maine	150	14	174	338	577	195
Massachusetts	89	20	116	225	506	126
New Hampshire	60	2	62	124	97	83
Rhode Island	19	0	19	38	28	28
Vermont	16	0	0	16	28	28
Total	**358**	**41**	**374**	**773**	**1,460**	**500**

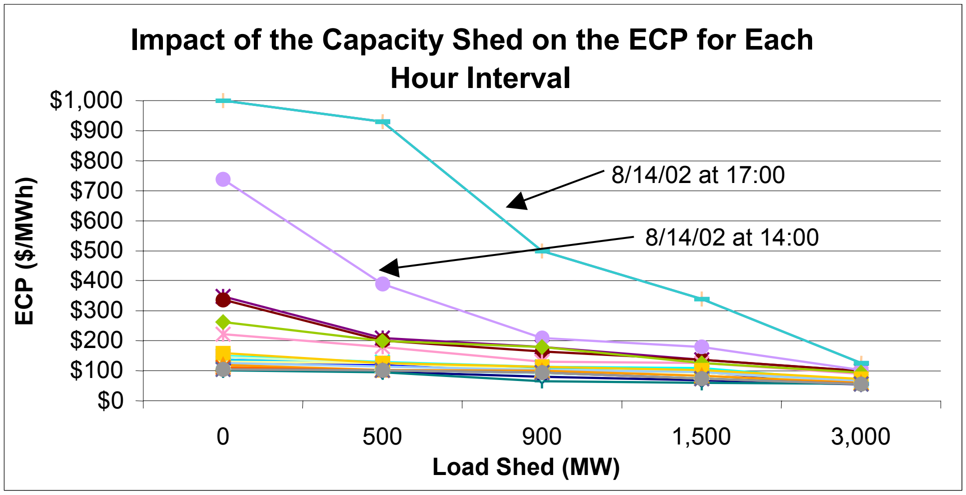
Then we analyzed the impact on the energy clearing price (ECP) of replacing utility generation with the units in Table 1 during high demand periods. We looked at load-shed levels of 500 MW, 900 MW, 1,500 MW and 3,000 MW, to determine the best level for each hour interval. Predictably, the price drop is directly proportional to the amount of load that is shed (see results in Table 2).

Table 2: Actual ECP and ECP Resulting from Shedding Loads (Fleyhan 2003)

Event Day	Hour End	*Actual Demand (MW)	* ECP ($/MWh)	** Bid Price with 500 MW shed; ($/MWh)	** Bid Price with 900 MW shed; ($/MWh)	** Bid Price with 1,500 MW shed; ($/MWh)	** Bid Price with 3,000 MW shed ; ($/MWh)
6/26	14	22,073	$102	$97	$80	$69	$55
6/26	15	22,249	$147	$125	$108	$97	$66
6/26	16	22,112	$126	$118	$102	$97	$63
7/23	13	24,087	$150	$129	$113	$109	$65
7/23	14	24,559	$348	$209	$179	$136	$99
7/23	15	24,533	$337	$200	$165	$136	$99
8/5	13	23,015	$101	$95	$66	$60	$57
8/5	14	23,527	$127	$118	$101	$95	$57
8/5	15	23,694	$137	$125	$107	$99	$57
8/13	16	24,731	$113	$102	$90	$80	$64
8/13	17	24,528	$147	$125	$103	$97	$65
8/13	18	24,149	$130	$125	$102	$94	$65
8/14	12	24,100	$126	$114	$102	$96	$66
8/14	13	24,757	$222	$180	$130	$125	$90
8/14	14	25,215	$738	$389	$209	$180	$102
8/14	15	25,344	$1,000	$930	$500	$339	$125
8/14	16	25,273	$1,000	$930	$500	$339	$125
8/14	17	25,150	$1,000	$930	$500	$339	$125
8/14	18	24,601	$262	$199	$179	$125	$94
8/19	12	22,179	$159	$125	$113	$102	$73
8/19	15	23,330	$119	$102	$100	$83	$60
8/19	16	23,295	$111	$101	$94	$74	$57
8/19	17	23,240	$105	$101	$94	$74	$56
8/19	18	22,868	$105	$101	$94	$74	$56
Average			**$288**	**$240**	**$164**	**$130**	**$77**

As shown in Table 2, the higher the load shed, the lower the ECP. All hour intervals reveal a significant drop in the ECP with an increase in capacity that can be curtailed. This trend is illustrated in Figure 1, where the ECP drop for each hour interval is represented as a function of the load shed. These numbers were determined using real bidding data and ECP.

Figure 1: Impact of Capacity Shed on the ECP



The higher the ECP dispatched for each hour, the steeper the drop in ECP at the different loads examined. For example, August 14, 2002 at 17:00 represents the largest drop because the ECP for that hour reached the cap limit of $1,000/MWh. The lowest ECP values were reached at 3,000 MW load shed, where the ECP had an average value of $77/MWh, with a minimum of $55/MWh, and a maximum of $125/MWh. If all DG units less than 5 MW in size were called, the 500 MW overall capacity would drop the ECP from an average level of $288/MWh to $240/MWh for the six days where Demand Response Program (DRP) was called. If the four-hour-long interval on August 14, when the ECP hit $738/MWh at 14:00, and $1,000/MWh from 15:00 to 17:00, were omitted, the average ECP for the six-day period would drop from $240/MWh to $130/MWh.

It is important to note that this reflects the impact of load shed on the ECP - not on the LMP. Nevertheless, it is clear that small DG units can provide more than half (500 MW) of ISO-NE's desired 900 MW to satisfy the requirements of its Real Time-Demand Response Program, which aims to lower the clearing price during peak demand periods. If, for example, 3,000 MW had been available during the days and hours in Table 2, the spot market price would have been cut by over $32 million. Even 500 MW would have reduced costs by almost $7.3 million.

CHP's Impact on LMP

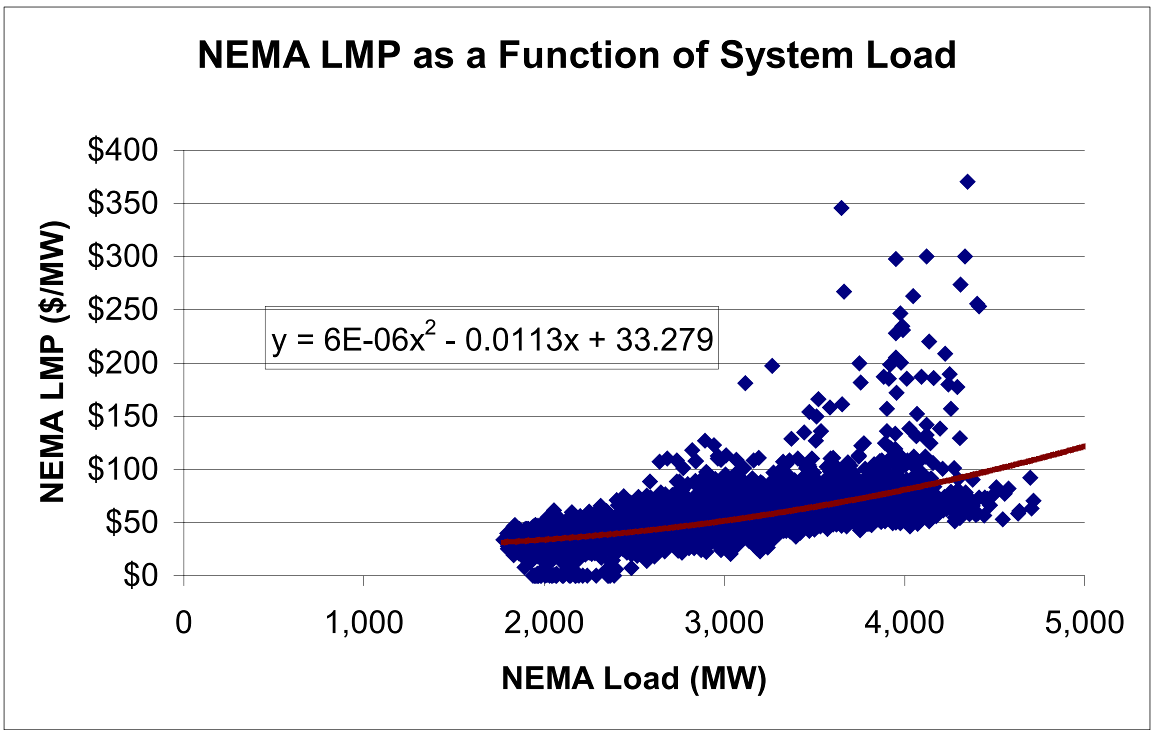
LMP is the sum of three components: energy (EC), congestion (CC), and marginal losses (MLC). The marginal loss component shows how much transmission losses over the system would change if one MW of power were injected. It is a function of voltage and the distance between generation and load. The congestion component is the nodal difference between the energy component and the cost of providing another more expensive unit of energy. The energy component is the energy price at a node.

Prices are calculated at more than 900 nodes throughout New England, and each node falls into one of eight zones: Maine, New Hampshire, Vermont, Rhode Island, Connecticut, Western/Central Mass., Northeastern Mass. (including Boston) and Southeastern Mass. Prices are determined using a load-weighted average in each zone. A hub – located in central Massachusetts, where transmission congestion is insignificant - provides a reference, or uncongested, energy price.

Our study indicates that all three LMP components improve when a CHP unit is installed on the grid. We looked at the LMP in the Northeastern Mass.(NEMA) zone from August 20, 2003 to August 19, 2004, and found that the LMP rose to 18 to 20 times its normal value on two occasions (12/5/03 and 1/14/04). The spikes were due mainly to high energy costs at the hub, with small contributions from congestion and loss (see figure 3). We set out to establish a mathematical relationship between LMP and load, using a best-fit line. Assuming a quadratic relationship, we developed the following equation (see figure 2):

$$\text{LMP} = 6 * 10^{-6} \times \text{LOAD}^2 - 0.0113 \times \text{LOAD} + 33.279$$

Figure 2: NEMA LMP as a Function of Zone Load



CHP's Impact on LMP Components

CHP can reduce the energy component by increasing the total amount of installed capacity, which decreases the need to dispatch expensive marginal generators, thereby increasing reliability and decreasing energy costs. Energy price spikes occur when expensive generators must be dispatched out of merit order to provide power to constrained portions of the grid. Price spikes also occur during proper merit order dispatching, since the lower-priced generators are called first.

The marginal increase of LMP as a function of load can be estimated by analyzing the relation between the energy component and the system load. By comparing the energy component with the corresponding LMP during on-peak and off-peak hours it is possible to calculate the wholesale power value and its increase as a function of system load. Assuming again a quadratic relationship, we developed the following equation for EC as a function of load (see figure 4):

$$EC_{LMP} = 7*10^{-6} \times LOAD^2 - 0.0202 \times LOAD + 44.58$$

Figure 3: NEMA LMP

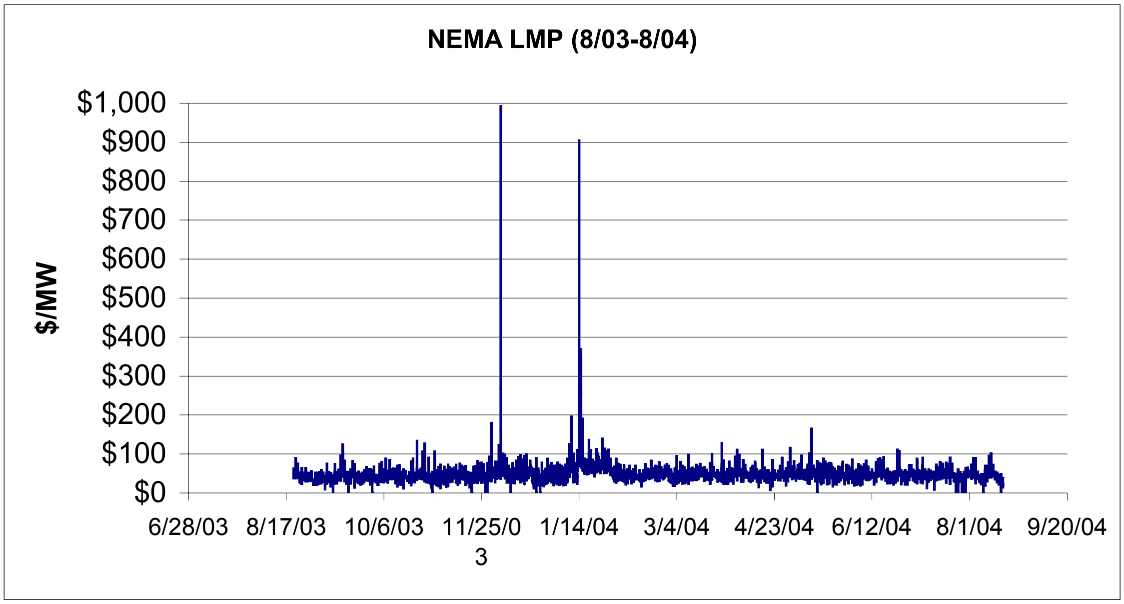
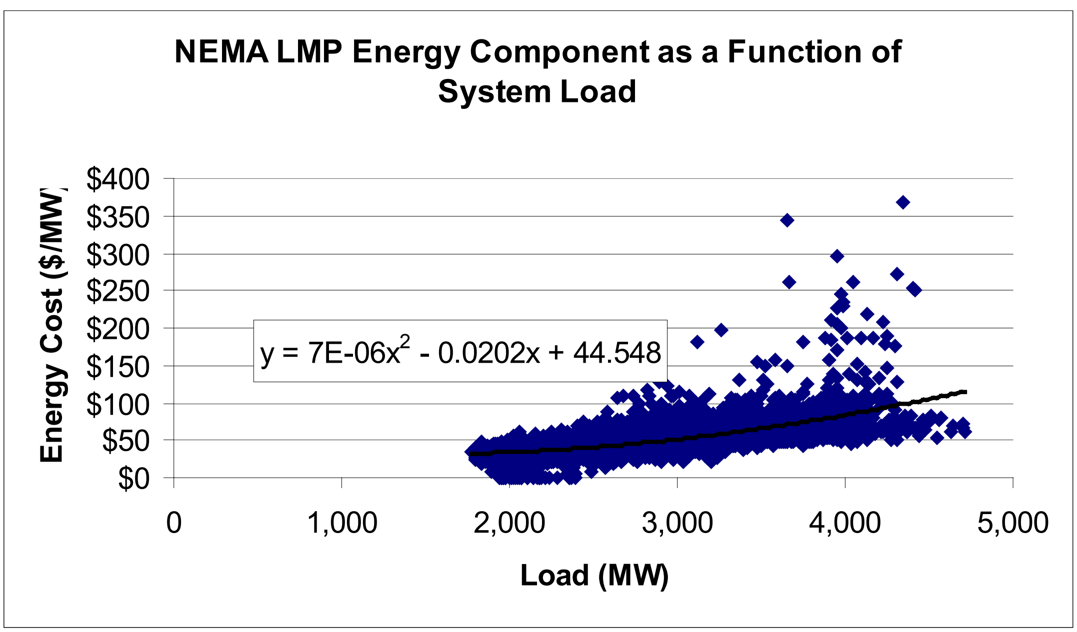


Figure 4: NEMA Energy Component of LMP as a Function of Load



This value can be extrapolated over the year to determine the economic impact of an LMP reduction, assuming that on average 3,500 MW of power is sold during the peak 25% of the day. Based on the equation above, the energy component reduction associated with a load reduction from 3,500 MW to 3,499 MW is $0.0288, which means the LMP is reduced by $0.0288/MW for power purchased throughout the year during on-peak hours. This corresponds to reduced wholesale energy costs to the utilities of $220,752/MW of installed CHP, or $220.75/kW-yr.

CHP can reduce the congestion component as well, but we must know how much power was sold in the real time spot market at the most congested nodes on the most congested days to determine that. The information allows us to evaluate the contribution of those nodes to the zonal LMP, and from this we can determine the areas of the grid most susceptible to binding constraints (important for locating transmission and distribution upgrades, as well as DG units), and can quantify wholesale market benefits.

We examined all nodes (ISO-NE 2004) for the period from August 2003 through August 2004 for congestion frequency. All nodes had nearly identical congestion patterns, suggesting that under normal operating conditions, NEMA nodes exhibit similar patterns. Table 3 is used to illustrate this behavior for most congested nodes in August of 2004.

Table 3: Congestion Incidents at Selected Nodes for August 2004 (ISO-NE 2004)

Sample Date	Node ID	Location Name	% of Hours With Positive Congestion Component	% Hours With Zero Congestion Component	% of Hours With Negative Congestion Component
8/1/04-8/31/04	4334	LD.MAPLWOOD115	23.65%	64.39%	11.96%
8/1/04-8/31/04	4108	LD.TRAPELO 115	23.79%	64.38%	11.83%
8/1/04-8/31/04	4347	LD.KING_ST 23	23.79%	64.38%	11.83%
8/1/04-8/31/04	4117	LD.SHERBORN13.8	23.79%	64.52%	11.69%
		Averages:	**23.76%**	**64.42%**	**11.83%**

By dividing the average positive congestion component by the number of NEMA nodes (104), we were able to determine the average contribution of a node's congestion component to the LMP. We assumed that: congestion occurred only during on-peak periods; an average of 300 MW was sold per hour on the Real Time spot market; 4,000 MW was purchased per hour overall for the entire NEMA market.

The average congestion cost per node was $611 in real time operation, and $8,151 in overall trades. If all 104 nodes in the NEMA region exhibited this behavior, the monthly increase in power purchases due to congestion was $63,576 in the real time market, and $847,679 in the overall market. These amounts were found by multiplying the real time and total surplus shown in Table 4 by the number of nodes, and they were estimated because we were not given complete information.

Table 4: Surplus Generation for Selected Nodes (ISO-NE 2004)

Sample Date	Node ID	Location Name	Average LMP Contribution During Positive Congestion Component Instances ($/MW)	Real Time Aug-04 Surplus	Total Aug-04 Surplus
8/1/04-8/31/04	4334	LD.MAPLWOOD115	0.011813736	$623.77	$8,316.87
8/1/04-8/31/04	4108	LD.TRAPELO 115	0.011644394	$614.82	$8,197.65
8/1/04-8/31/04	4347	LD.KING_ST 23	0.012194056	$643.85	$8,584.62
8/1/04-8/31/04	4117	LD.SHERBORN13.8	0.010658953	$562.79	$7,503.90
		Averages:	**0.011577785**	**$611.31**	**$8,150.76**

The annual impact of congestion on all trades in the NEMA zone is calculated as follows:

$$ACC_{NEMA} = MCC_{NEMA} \times \left(M_S + M_W \times F1\right)$$

Where,

ACC_{NEMA} = Annual congestion cost, NEMA zone;
MCC_{NEMA} = Monthly congestion cost, NEMA zone;
M_S = Summer months;
M_W = Winter months;
$F1$ = De-rating factor; 0.85

We used a de-rating factor during the winter months because the system load is less during that period. Thus,

$$ACC_{NEMA} = \$847{,}679 \times \left(6 + 6 \times 0.85\right) = \$9{,}409{,}237$$

This value, $9,409,237, is for all 104 nodes over a year. The congestion impact per node is $90,472/yr. Calculating on a per unit power basis enables us to quantify the externality benefit of a CHP unit in congestion mitigation.

The average NEMA load during this period was 2,978 MW in the Day Ahead market, and 3,187 MW in operation, which corresponds to average hourly real time purchases of 209 MW (ISO-NE 2004). During on-peak hours the system load will generally be greater than average. Our analysis assumes that congestion occurs during on-peak hours, and represents 4,000 MW in overall purchases and 300 MW real time purchases. If all nodes are weighted equally, the simple average NEMA nodal load is 38.5 MW during on-peak hours. Calculations were done on an average basis due to lack of real nodal data.

Congestion generally occurs on the margin, at the last 5-10% of the load. Assuming a 10% reduction in load is required to eliminate congestion costs (this value corresponds to 3.85 MW per node, or 400 MW for the zone), the annual congestion mitigation value can be determined by dividing the annual congestion impact, $90,472, by the load required to mitigate that congestion, 3.85 MW. Thus, the annual congestion mitigation value is $2,350/MW-yr, or $23.50/kW-yr.

Congestion usually occurs when a single line becomes highly congested, or when many nodes become congested. We removed the top 5 congested nodes and recalculated the zonal LMP to determine the contribution of these nodes to congestion. Table 5 shows the results, and the subsequent surplus that would be generated. Surplus was evaluated by multiplying the re-calculated LMP by the amount of power sold on the Real Time Spot Market. The total surplus available is a function of the LMP reduction and the total amount of power traded on the wholesale market during that hour.

As these results indicate, mitigating congestion at even a small number of critical nodes has a significant economic impact. For example, on July 22, 2004, mitigating congestion at 5 of 104 nodes at 6 p.m. would have reduced the real time LMP 28.56%. We estimate that 19.25 MW (5 nodes at 3.85 MW each) of CHP would provide this benefit. Congestion in the NEMA zone costs more than $9.41 million per year.

Table 5: LMP Reduction on High Congestion Days (ISO-NE 2004)

Date	Average Percent Reduction In LMP	Hours	RT Surplus Generated	Total Surplus Available
December 4, 2003	1.11%	7	$767	$41,205
July 22, 2004	13.75%	5	$18,973	$217,425
August 3, 2004	10.28%	2	$9,830	$78,863
August 4, 2004	6.95%	3	$3,359	$49,677
	Total:		**$32,929**	**$387,170**

System Benefits Analysis

Introduction

We studied an 800 kW CHP generator in the Boston area to determine its benefits as a function of system capacity, increased fuel efficiency, planned T&D upgrades, system losses, and emission reductions. The system will be assumed to operate for 10 years. The unit's specifications are shown in Table 6.

Table 6: Specifications for Caterpillar 800 kW Reciprocating Natural Gas Generator with CHP

Characteristics	
Electric Capacity	800 kW
Total Installed Cost ($/kW)	$1,000
Electric Heat Rate (Btu/kWh)	10,246
Electric Efficiency (%)	33.30%
Engine Speed (RPM)	1200
Fuel Input (MMBtu/hr)	7.60
Required Fuel Gas Pressure (psig)	<3
Exhaust Flow (1,000 lb/hr)	10.9
Exhaust Temperature (F)	1,067
Heat Recovered from Exhaust (MMBtu/hr)	2.12
Heat Recovered from Cooling Jacket (MMBtu/hr)	1.09
Heat Recovered from Lube System (MMBtu/hr)	0.29
Total Heat Recovered (MMBtu/hr)	3.50
Total Heat Recovered (kW)	1,025
Form of Recovered Heat	Hot Water
Total Efficiency (%)	76%
Power/Heat Ratio	0.78
Net Heat Rate (Btu/kWh)	4,774
Effective Electrical Efficiency	0.71

Customer Costs and Benefits

Benefits

The annual electricity bill reduction will be calculated using the facility's T-2 NSTAR rate of $15.93/kW (demand) and $0.0646/kWh (energy)(NSTAR 2005). We assume the unit is installed in a high-capacity facility and operates for 8,000 hours annually with a load factor of 0.5. The electricity displaced by CHP results in customer savings of $359,648, and natural gas savings equal $153, 720, for a total customer benefit of $513,368.

Costs

A standby charge of $6.18/kW from October to May, and $11.77/kW from June to September (NSTAR 2005) went into effect for units this size on December 31, 2004, and these costs are $77,220 for this customer. The installed cost for an 800 kW unit is approximately $1,000/kW, so the total installed cost is $800,000. The financing period for this unit is assumed to be 10 years, with a 10% annual interest rate. Thus the annual payment for the unit is assumed to be $88,000 for 10 years.

According to the manufacturer, the full load fuel consumption of the unit is 7.60 MMBtu/hr. It is assumed that fuel consumption varies linearly with load. Thus, with a load factor of 0.5 assumed over 8,000 operating hours, the annual consumption is 30,400 MMBtu, and the annual customer cost of fuel is $333,792. Annual operation and maintenance costs, which are estimated to be $0.01/kWh, total $32,000. Since the CHP unit in question is natural gas-fired, it is assumed that no emission offsets will need to be purchased. It is further assumed that the facility has adequate availability to natural gas lines, and that there are no significant upgrade requirements for any other utilities, outside of the electric utility.

The typical cost of an interconnection study is $2,000, (Beaudoin 2002) but equipment and electric system upgrades can bring the cost of interconnection much higher. For this analysis we assume upgrade costs of zero, and divide study costs by the number of years (10) to determine ACC_{IC}, annual customer cost of interconnection; thus $ACC_{IC} = \$200$. Thus the total customer cost is $531,212.

Utility Costs and Benefits

Benefits

Data from August 2003 to August 2004 indicate that LMP for the NEMA zone averages approximately $49.62/MW (ISO-NE 2004). For an 800 kW demand reduction, factoring in T&D losses of 11%, (NEPOOL 2003) the utility's avoided wholesale purchases are $176,250. As indicated earlier, substantial upgrades to the transmission system in and around Boston are required. The value of annual transmission deferment is the product of transmission deferral value ($57.92/kW-yr) and electric demand (800 kW), or $46,336 per year. The value of annual distribution upgrade deferment is the product of distribution deferral value ($5.22/kW-yr) and electric demand (800 kW), or $4,176 per year.

In addition, distributed generation can lower the zonal LMP, which decreases the cost utilities pay on the wholesale market during constrained hours. Cost reductions were valued at \$220.75/kW-yr, as determined earlier.

$$AUB_{LMP\text{-}E} = \$220.75 \times 800 = \$176{,}600$$

Congestion cost reductions were valued at \$23.50/kW-yr.

$$AUB_{LMP\text{-}C} = \$23.50 \times 800 = \$18{,}800$$

The impact of CHP on the LMP and loss components is not calculated here. Though it is expected to be relatively small, it should be included in future iterations of this model.

The total utility benefit is \$499,382.

Costs

Revenue reduction is equal to the electric saving seen by the customer, and in this study there is an electric reduction of 3,200,000 kWh at a revenue reduction of \$206,720, along with an annual demand reduction of 9,600 kW at a revenue reduction of \$152,928. The total electrical revenue reduction is \$359,648.

It is assumed that there are no system upgrades required, and that there are no incentives provided to the customer by the utility.

The total utility cost is \$359,648

Natural-Gas Utility Benefits and Costs

The increased use of natural gas due to the CHP unit, less the reduction in natural gas purchased for the facility's thermal load, will be equal to the fuel cost increase to the customer to fire the CHP unit minus the annual avoided fuel costs. The benefit to the gas utility is \$180,072.

Natural gas supply and delivery costs are 90% of the customer cost, so the natural gas utility cost is simply the product of the annual customer cost of natural gas (\$180,072) and this fraction (0.9), or \$162,065.

Societal Benefits

The value of installed capacity deferment is equal to \$350/kW. System losses are approximately 11%, so the value of DG value is 11% higher than nameplate capacity because it is not subject to these losses. The equivalent capacity value that the 800 kW CHP unit would generate is \$31,080.

Reduced emissions equal the centrally generated electricity that is displaced (including losses) plus the amount of displaced natural gas that was used for the on-site thermal process, minus the local natural gas increase due to the CHP unit. Using appropriate emission factors, overall emission reductions were found, and savings were determined based on damage costs calculated in Roth, 2000. The CHP unit generates more NOx than a natural gas-fired boiler, but less CO_2. As control technologies improve, emissions such as NOx will decrease. Note that there are no increased societal costs associated with this CHP installation. The results are summarized in the Table 7 below.

Table 7: Stakeholder System Benefit/Cost Model – High Capacity – 8,000 Annual Hours of Operation

	Benefits			Annual Costs			
Customer	Annual Avoided Electric Bill Savings	Energy	$206,720	Annual Electric Standby		$77,220	
		Demand	$152,928	Increased Annual Fuel Cost		$333,792	
	Annual Avoided Fuel Costs		$153,720				
	Wholesale Energy Sales		--	Annual O& M Cost		$32,000	
				Interconnection Charges		$200	**Customer Benefit:**
		Sub-Total:	$513,368		Sub-Total:	$443,212	**$70,156**
Electric Utility	Avoided Wholesale Energy Purchase		$176,250	Annual Electric Sales Reduction	Energy	$206,720	
	Annual Electric Standby		$77,220		Demand	$152,928	
	Avoided Transmission Investments		$46,336	System Upgrades		--	
	Avoided Distribution Investments		$4,176	Incentives to DER Customers		--	
	Decreased Spot Market Energy Price	Energy	$176,600				
		Loss	--				
		Congestion	$18,800				**Electric Utility Benefit:**
		Sub-Total:	$499,382		Sub-Total:	$359,648	**$139,734**
Natural Gas Utility	Increased Natural Gas Sales		$180,072	Increased Wholesale Purchases		$162,065	**Natural Gas Utility Benefit:**
		Sub-Total:	$180,072		Sub-Total:	$162,065	**$18,007**
Society	Avoided Installed Capacity Value		$31,080				
	Emission 'Damage Costs'		$21,948				
	Increased Reliability		--				**Society Benefit:**
		Sub-Total:	$53,028		Sub-Total:	$0	**$53,028**
		Total Benefit:	$1,245,850		**Total Cost:**	$964,925	
		Net Benefit Per Year	**$280,925**				
		Net Benefit (per kW-yr)	**$351.15**				

Equally important are the standby charges recently (July 26, 2004) approved by the Massachusetts Department of Telecommunications and Energy, which allow NStar to alter the economics of CHP. Without those charges, the simple payback of the CHP unit in this example is reduced from 12.5 years to 6.0 years.

Furthermore this analysis, which is extremely sensitive to parameter changes, would look very different if the price of natural gas dropped, or if the transmission system were strained because of very hot weather. The past two summers have been mild in the northeastern U.S., so the grid was not stressed during the period for which we performed our calculations.

References

Beaudoin, H. 2002. Combined Heat and Power in New England: Guidelines and Barriers To Implementation with Case Studies. Masters Thesis: University of Massachusetts. Amherst, MA.

U.S. Department of Energy. 2002. Inventory of Non-Utility Power Generators by State

Fleyhan, Z. 2003. Investigation and Evaluation of the Electricity Market Operation in New England. Masters Thesis: University of Massachusetts. Amherst, MA

ISO-New England. 2004. CELT Report 2004. <http://www.iso-ne.com/Historical_Data/CELT_Report/> .

ISO-New England. 2003. LMP White Paper. March 6, 2003.

NEPOOL. 2003. Regional Transmission Expansion Plan 2003. http://www.iso-ne.com/smd/transmission_planning/Regional_Transmission_Expansion_Plan/RTEP_2003/0311_RTEP03_Exec_Summ_BOD_Approved-Rev.doc/

NSTAR. 2005. Electric schedule of rates. http://www.nstaronline.com/ss/customer_service/rates/schedule.asp

Roth, I. 2000. Incorporating Externalities in Electric Power Generation Life-Cycle Costing. Masters Thesis: University of Massachusetts, Amherst, MA.