Impacts of Distributed Generation on Wholesale Electric Prices and Air Emissions in Massachusetts

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Executive Summary

Increasing the quantity of Massachusetts customer energy requirements met through distributed generation (DG) and energy efficiency (EE) will reduce the quantity of electricity that needs to be purchased from the wholesale market administered by ISO-New England (ISO-NE). There are numerous potential benefits to all customers from such an increase in DG and EE. The objective of this study was to estimate two potential benefits in particular, impacts on prices for electric energy purchased from the wholesale market and impacts on air emissions associated with those purchases. The analyses presented in this study demonstrate that increased DG and EE could benefit all customers by reducing both wholesale electric energy prices and air emissions.

The study estimates the impacts of increased DG and EE by simulating the hourly operation of the wholesale electric energy market in 2020 under each of several scenarios or cases. First, it determines wholesale electric prices and air emissions under a Reference scenario. Then it determines wholesale electric prices and air emissions under several alternative scenarios, each of which reflect an increased quantity of DG and/or EE.[1] These scenarios represent impacts of potential new policies and programs, not just naturally occurring demand resources. Finally, it estimates the impacts of increased DG and EE by comparing the results of each alternative scenario to the results under the Reference scenario. Each scenario is described briefly below.

The Reference scenario is essentially a "business as usual" case, with one exception. It assumes no spending on ratepayer funded demand side management (DSM) programs after 2007, and hence no incremental energy savings from DSM beyond the savings resulting from DSM programs implemented through 2006.[2] The Reference case also assumes no new policies to encourage incremental DG. Under this case the load of Massachusetts customers that would be met by purchases from the wholesale market is drawn directly from the ISO-NE 2007 long-term forecast of capability energy load transmission ("CELT"). That forecast reflects a compound annual growth rate (CAGR) in Massachusetts energy consumption of 1.0%.

The study analyzed four alternative scenarios or cases with the following new demand resources added through 2020:

- a photovoltaic (PV) case, which assumes 250 MW of incremental DG from PV;

[1] For each alternative scenario the study simulates the wholesale market for the year 2020. Except for the Reference Case, this study did not simulate the evolution and operation of wholesale market year by year from 2007 to 2020.

[2] Synapse Energy Economics originally designed this Reference Case on behalf of DSM program administrators in New England for the purpose of estimating the value of future DSM, i.e. avoided costs. See *Avoided Energy Supply Costs in New England 2007 Final Report,* August 2007 ("AESC 2007). Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2007-08.AESC.Avoided-Energy-Supply-Costs-2007.07-019.pdf

- an energy efficiency (EE) case, which assumes incremental investment in energy efficiency sufficient to reduce the annual growth of MA energy consumption to 0.6%;
- a combined heat and power (CHP) case, which assumes 750 MW of incremental DG from CHP; and
- a case with both DG and EE (CHP+EE) Case, which reflects the combined impacts of the CHP and EE cases.[3]

The combined effect of all these new demand resources would be to virtually eliminate load growth in Massachusetts as illustrated in Figure ES-1.

Figure ES-1. Load of MA customers met by purchases from wholesale market in 2020 under Reference, EE and CHP+EE cases

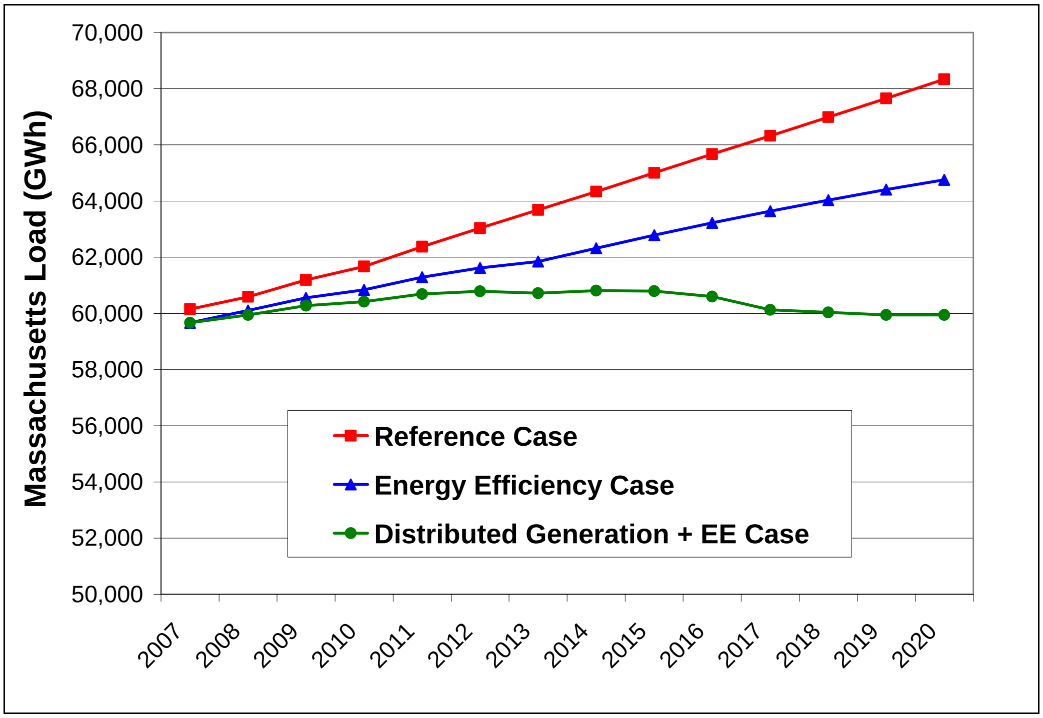

Figure ES-1 shows the load of Massachusetts customers that would be met by purchases from the wholesale electric energy market for the Reference Case, the EE case and the CHP+EE cases respectively.[4] As can be seen in the figure, the CHP+EE case reduces the quantity of energy purchased from the wholesale electricity market in 2020 to today's

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[3] For purposes of running the simulation model, this combined case was limited to CHP and efficiency.

[4] The loads shown in Figure ES-1 represent scenarios, not forecasts. The CHP+EE Case is based upon an estimate of CHP penetration in Market Potential of Combined Heat and Power in Massachusetts, prepared by KEMA for Massachusetts Technology Collaborative, March 2008: http://www.masstech.org/dg/2008-03-MA-CHP-Market-KEMA.pdf

levels. That is approximately a 13% reduction in purchases of wholesale energy in 2020 relative to the Reference Case, as a result of new CHP and energy efficiency resources.

The key load and resource characteristics of the alternative scenarios are presented in Table ES-1. To reach the levels of DG and EE modeled in this study would require annual growth rates of 35% for PV, 15% for efficiency and 16% for CHP from 2007 through 2020. As a result of this growth, the portion of annual 2020 Massachusetts energy requirements met by these demand resources would be 1% from PV, 5% from efficiency, and 7% from CHP, for a total of 14% (including PV).

Table ES-1. Key Load and Resource Attributes of Alternative Scenarios

	PV: Photovoltaic	**EE: Energy Efficiency**	**CHP: Combined Heat and Power**	**CHP + EE**
DG and EE Resources				
Incremental Installed Capacity in 2020 (MW) [1]	**250**	**812**	**750**	
Average Capacity Factor	16%	50%	67%	
Incremental Annual Energy (GWh/year) [2]	356	3,568	4,458	8,026
2007 Output from Existing DG & EE [3]	6	487	637	1,124
2020 Output from DG & EE [4]	361	3,568	5,095	9,025
Annual Growth in output (2007-2020) (% / yr)	**35%**	**15%**	**16%**	**16%**
Massachusetts Energy Requirements				
Peak Requirements in 2020 (MW)	15,525	15,525	15,525	
Portion of MA Peak Demand met by DG and EE in 2020	**1%**	**5%**	**4%**	
Annual Energy Requirements (GWh/year)	68,450	68,450	68,450	68,450
Portion of Annual Energy met by DG and EE in 2020	**1%**	**5%**	**7%**	**13%**
Annual Growth in energy required from ISO-NE (2007-2020) (% / yr)	**1.0%**	**0.6%**	**0.5%**	**0.0%**

Note 1 – EE MW estimated based on assumption EE has same average load factor as Massachusetts load in 2020.
Note 2 – The row "Incremental Annual Energy" specifies the quantity of each resource that was modeled in this study.
Note 3 – Sources: RET, DOER, KEMA. CHP GWh based on 97 MW installed since 1984 at 75% capacity factor.
Note 4 – Assumes efficiency savings from measures as of 2007 have dissipated.

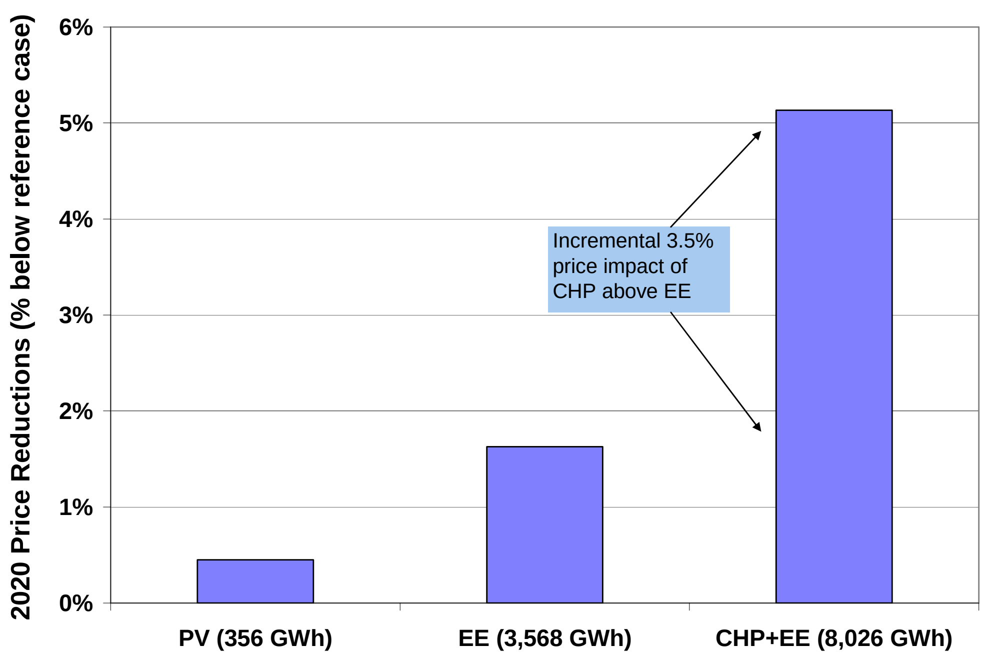
Comparing the results of each alternative scenario to the results of the Reference Case leads to conclusions in three areas which will be described in the remainder of this Executive Summary: the reduction of wholesale electricity prices, the price effect attributable to each demand resource, and the impact on greenhouse gas emissions.

Reduction of Wholesale Electricity Market Prices

The annual average wholesale market price of electric energy in 2020 could be reduced by approximately 5 % below prices under the Reference Case if the DG and efficiency resources introduced above are installed by electricity customers in Massachusetts, as illustrated in Figure ES-1 below.

The fact that a reduction in the quantity purchased from the wholesale market would lead to a reduction in the price for electric energy in that market is consistent with both economic theory and the procedure through which prices are set in that market. Wholesale prices in each hour are set by the cost of electricity from the last, or marginal, unit dispatched in that hour to meet the last unit of energy load in that hour. If the load in a given hour is reduced, it may be possible to meet the new, lower load with a different marginal unit at a lower price of electricity. This effect has been identified in other studies and is sometimes referred to as a Demand-Reduction-Induced Price Effect ("DRIPE" or "price effect").

Figure ES-2. Reduction in average annual wholesale electric energy price for Massachusetts purchases in 2020 under PV, EE and CHP+EE cases[5]



5 The impact of 750 MW of CHP is the price reduction from the scenario with energy efficiency included. The price reductions for the other bars in this chart are from the Reference Case.

As shown in this chart, prices would be reduced by 1.6% as a result of energy efficiency, and the incremental CHP in the CHP + EE case would produce an additional 3.5% reduction in wholesale energy prices.

This impact represents a significant benefit of DG and EE to all customers. Individual customers who invest in DG and/or EE, e.g. "participants", receive a direct benefit from that investment in the form of reduced purchases "from the grid" and a reduction in their annual electricity bill corresponding to those reduced purchases. *In addition*, to the extent that the reductions in purchases from the grid due to DG and EE lead to a reduction in the price of electric energy in the wholesale market, all customers benefit – including "non-participants".

The annual benefit of the reductions in wholesale prices to all customers in Massachusetts under each alternative scenario can be estimated by multiplying the reduction in wholesale prices times the remaining Massachusetts load to be met by purchases from the wholesale market. For example, under the PV scenario, the 250 MW of incremental Massachusetts PV in 2020 is expected to displace 356 GWh of purchases from the wholesale market and reduce wholesale market prices in the Massachusetts load zones by $0.33/Mwh or 0.4%. The benefit to all customers in Massachusetts is equal to that reduction multiplied by the remaining 68,094 GWh,[6] or approximately $23 million. The corresponding benefits to all customers from the other alternative scenarios are approximately $80 million under the EE scenario and $230 million under the CHP+EE scenario. The incremental reduction from CHP, beyond the reduction from efficiency, is therefore approximately $150 million for these Massachusetts customers.

These estimates are based upon reductions in wholesale market prices. The reductions received by customers who are not purchasing electricity at prices linked directly to wholesale market prices may be different from these estimates, but the direction and magnitude of their reductions should be similar over time.

These estimates are only for the load of Massachusetts customers met by purchases from the wholesale market. Massachusetts represents only about 45% of ISO-NE electricity consumption. This report understates the benefits of DG by not including the generally similar level of reductions in wholesale market prices in the rest of New England, and the corresponding reductions in energy costs that those other customers would also experience and benefit from.

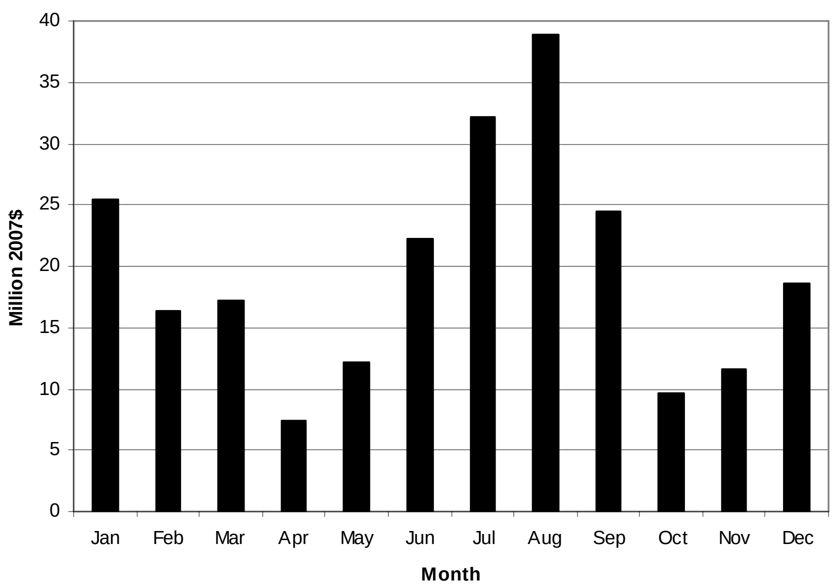
The duration and magnitude of reductions in wholesale market prices are a function of a variety of factors which interact in complex ways. In the short term a reduction in demand results in a reduction in wholesale price following basic economic laws of supply and demand. In the longer term the supply side will adjust to lower prices, for example closure of inefficient existing plants or postponement of new projects. That could cause prices to rise and offset the price reduction effect somewhat. However it is unlikely that existing capacity with low- to moderate- generation costs will be retired. Thus any price rebound will primarily occur in a relatively few hours with peak prices. This indicates

6 Quantity from wholesale market of 68,094 GWh = Total Load of 68,450 GWh minus 356 GWh from PV

that price reductions from reducing the level and shape of the load met from the wholesale market should be long-term and unlikely to be materially offset by any price rebound due to supply-side reactions.

Figure ES-3 shows the wholesale energy cost savings to Massachusetts customers due to the impacts on wholesale market prices under the CHP+EE case, illustrating a distinctly seasonal pattern.

Figure ES-3. Total energy market cost savings attributable to the price differential between the CHP+EE Case and the Reference Case by month for Massachusetts

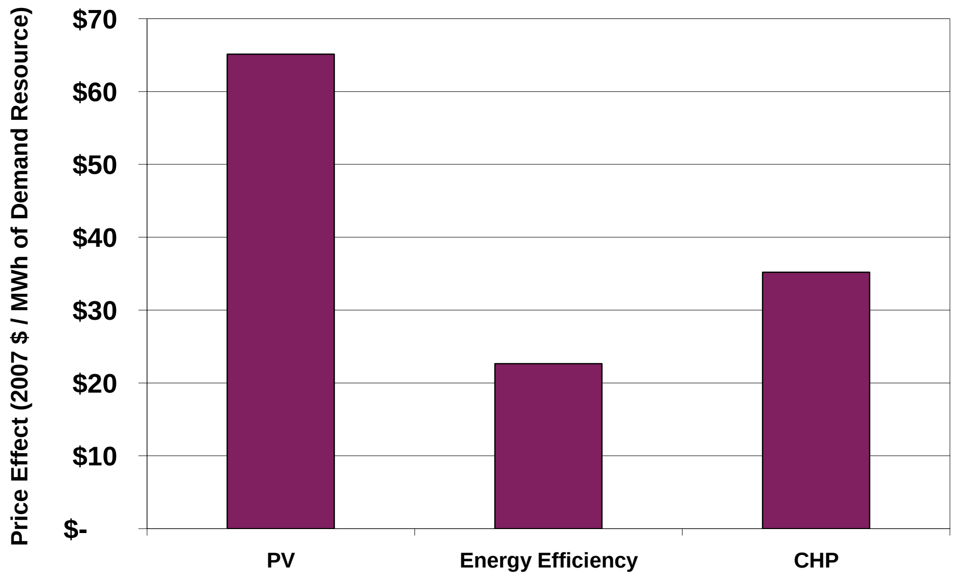


Price Effect Attributable to Each Demand Resource

Using these results, the study then examined how the level of impact on wholesale energy costs varied by scenario. These "price effects" are presented in Figure ES-4, expressed as wholesale market cost savings to Massachusetts customers per MWh of DG and/or EE responsible for those benefits. The values in Figure ES-4 are equal to the energy cost savings described earlier divided by the quantity of DG energy generated and/or energy saved by EE or DG in each scenario.[7]

[7] The values in Figure ES-4 are calculated by first multiplying the net load (gross load minus demand resource savings) in each scenario by the average price differential in each scenario and then dividing by the quantity of energy generated or saved by the demand resources in that scenario.

Figure ES-4. Price Effect: impact on annual costs of Massachusetts purchases of wholesale electric energy in 2020 from PV, EE and CHP (2007 dollars)[8]



This figure demonstrates that PV has the highest benefit -- $65/MWh -- in terms of impact on wholesale energy market costs, despite the earlier figures indicating that the absolute impact of PV is smaller than the EE and CHP resources examined in this study. The price effect from energy efficiency is $23/MWh saved in 2020. The effect of incremental CHP above the EE Case is $35 per MWh of CHP generation ($155 million/4,458 GWh).

The differences in benefit per MWh are consistent with the differences in the "shapes" or hourly profiles of PV generation, savings from EE and generation from CHP.[9] PV generation generally occurs in hours when wholesale electric energy market prices are highest. In contrast, we assumed savings from EE would have the same load shape as hourly purchases from the wholesale market, and that a significant portion of CHP output would be relatively constant in each hour, but higher during business hours, as described below.

8 The price impact from CHP in this chart is based on the incremental price impact of the CHP+EE Case relative to the EE Case.

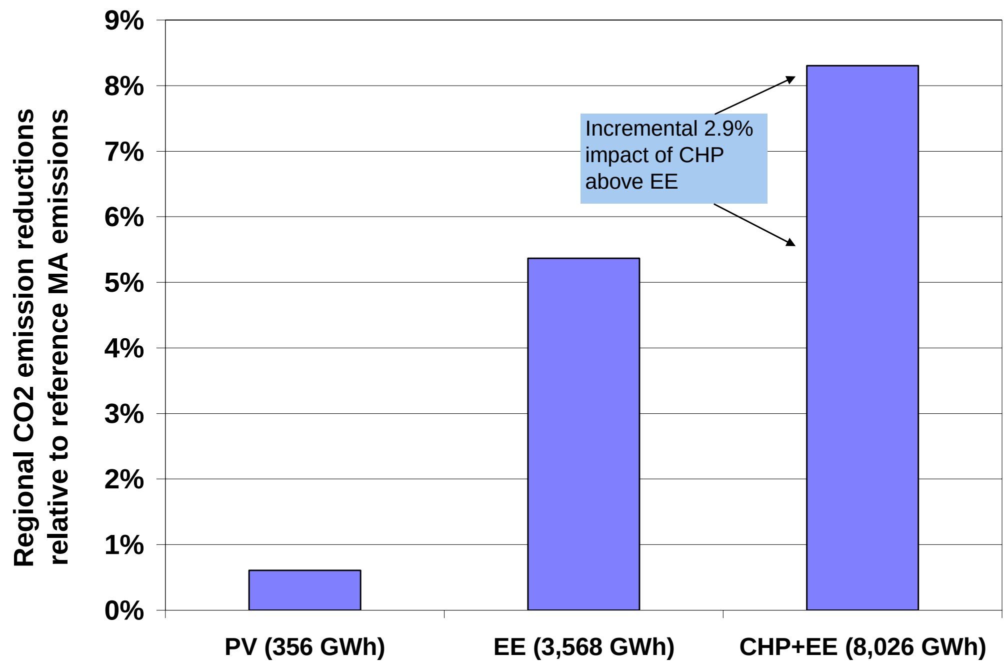
9 This refers to the variation in energy generated, or saved, by hour over a year.

Impact on Greenhouse Gas Emissions

Under the CHP+EE Case the annual quantity of CO_2 emissions from generation sold into the wholesale electric energy market in 2020 could be significantly reduced from the levels expected under the Reference Case. CO2 emissions in 2020 under the CHP+EE case are approximately 2.4 millions short tons/year less than under the Reference Case.[10] While most of these reductions take place at generators in the ISO-NE region, some of them represent reductions of emissions at power plants in adjacent control areas.

Figure ES-5 summarizes the greenhouse gas reductions from each scenario by comparing them against the Massachusetts share (based on GWh load) of the Reference Case CO2 emissions from the ISO-NE region. This does not represent a reduction percentage per se, but it provides a frame of reference for these emission reduction figures.

Figure ES-5. Reductions in regional CO_2 emissions in 2020 under PV, EE and CHP+EE cases relative to Reference Case Massachusetts CO2 emissions



The major contributor to these greenhouse gas reductions in energy efficiency, responsible for a reduction of 1.6 million tons in 2020, or 5.4% of the Massachusetts emissions in the Reference Case. CHP provides an incremental 2.9% reduction beyond the EE Case.

[10] The CO2 emission reductions presented in this section are net of the emissions associated with the gas used in the incremental CHP capacity, as described in the body of the report.

Summary

Table ES-2 summarizes key results from the previous charts. These results are further described in this rest of this report.

Table ES-2. Selected 2020 Results of Alternative Massachusetts Demand Resource Scenarios[11]

	PV: Photovoltaic	EE: Energy Efficiency	CHP: Combined Heat and Power	CHP + EE
New Resources, 2020 (MW)	250	812	750	
New Resources (GWh/year)	356	3,568	4,458	8,026
Resources as % of MA Energy	0.5%	5.2%	7.4%	12.7%
Price Reduction	**0.4%**	**1.6%**	**3.5%**	**5.1%**
Cost Reduction ($000)	$23,163	$80,805	$155,130	$235,935
Price Effect ($/MWh)	**$65.14**	**$22.64**	**$34.80**	
CO2 Reductions from Regional Grid (gross 000 short tons)	177	1,568	1,944	3,512
CO2 Reductions (net 000 short tons)	177	1,568	838	2,406
CO2 Net Reductions Compared to MA Reference (%)	**0.6%**	**5.4%**	**2.9%**	**8.3%**
Reductions from Regional Grid (gross lb/MWh)	994	879	872	
Net CO2 Reductions (lb/MWh)	**994**	**879**	**374**	

11 CHP values in this Table may represent incremental impacts from the CHP+EE Case relative to the EE Case, or they may represent average ratios for CHP resources, depending on the context.

1. Introduction

In its 2006 Report to the Massachusetts Department of Public Utilities, the Massachusetts Distributed Generation (DG) Collaborative recommended that the impact of DG on market prices be explored in future work, saying

> "…end-use customers who install DG reduce their dependence on the regional market for their energy needs, which may contribute to a decrease in energy price volatility. Reductions in regional energy demand should result in lower market clearing prices that benefit all customers"[12].

The 2006 Report also stated that

> "…the participants in the DG Collaborative plan to undertake the following activities: …7: Explore the following areas of potential DG value: impact of DG on constrained areas, impact of DG on market prices, and impact of DG on the environment"[13].

In response to these collaborative recommendations, the Massachusetts Technology Collaborative (MTC) has engaged Synapse Energy Economics (Synapse) to prepare the present study[14]. This study provides a detailed analysis of the impacts of DG resources on wholesale electric energy prices and air emissions in Massachusetts. There are a wide range of DG resources. Two DG resources were modeled in this study, photovoltaic (PV) and combined heat and power (CHP). These two resources are very complementary. PV provides no-emission electricity primarily during hours of peak load and peak prices in the wholesale market. CHP provides low cost and low-incremental emission energy during most hours throughout the year.

DG reduces the quantity of electricity that customers acquire from the wholesale electric market. As a result, those resources have the potential to reduce the level and volatility of wholesale electricity market prices, as well as to reduce the air emissions resulting from generation in that market. The magnitude of those reductions will depend primarily on the magnitude and profile of the DG and the fundamental demand and supply factors driving the operation of the wholesale electricity market.

Potential Impact of DG on Wholesale Electricity Market Prices

DG has the potential to reduce prices in the wholesale electricity market by reducing the quantity of energy and/or capacity that customers will need to acquire from that market. This impact, i.e. a reduction in demand from wholesale markets resulting in a reduction

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12 Massachusetts Distributed Generation Collaborative, *2006 Report to the Massachusetts Department of Telecommunications and Energy*, DTE 02-38-C, 2006, p. 37.

http://www.masstech.org/dg/02-38-C_2006-Report_DGcollab.doc#_Toc139361544

13 Ibid., p. 46.

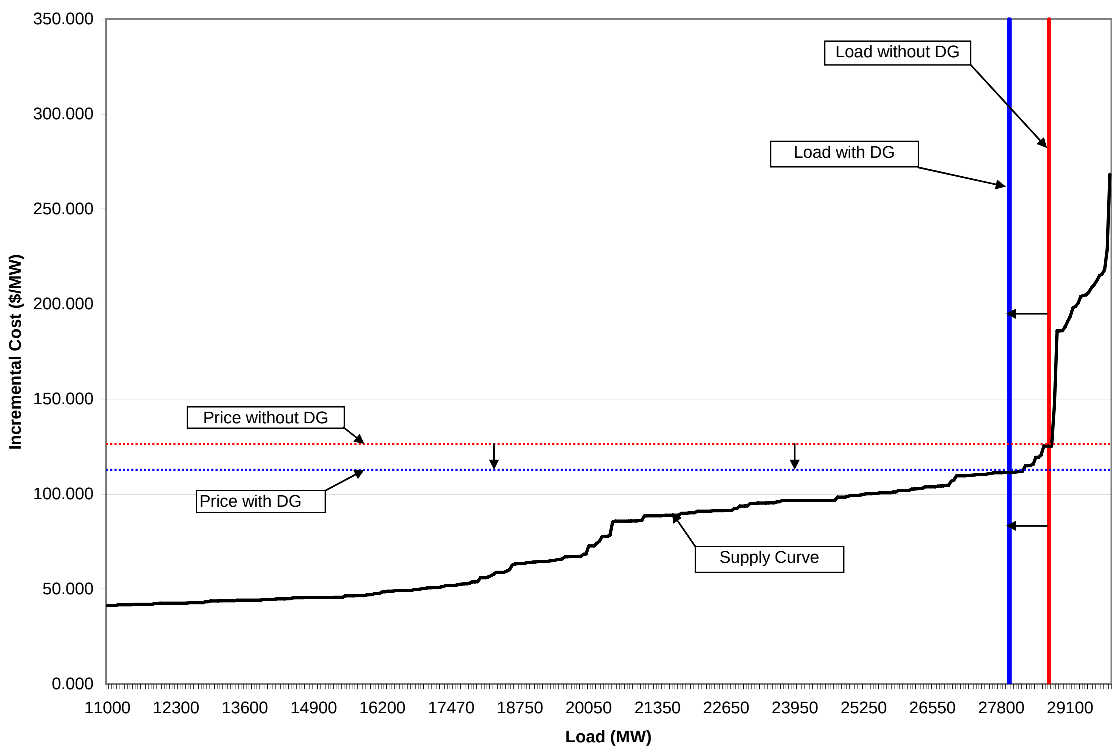
14 For further information regarding the ongoing assessment of the costs and benefits of DG, see http://www.masstech.org/dg/Benefits.htm.

in wholesale market prices, has been referred to as the Demand-Reduction-Induced Price Effect ("DRIPE" or "price effect").

Wholesale electric energy prices.

In the wholesale electric energy market operated by ISO-NE hourly market prices are set by the last or marginal generating resources dispatched during that hour. Those electric energy market prices are therefore a function of the quantity of demand in each hour and the bid prices submitted by generating units available to meet that demand in that hour. This market price dynamic is clearly reflected in the varying hourly prices seen in ISO NE's structured hourly spot energy markets. With increased penetration of DG resources, the quantity of demand seen in the ISO-NE wholesale electric market will be less than it would otherwise have been. If the magnitude of that reduction in demand is significant, those markets will "clear" at prices set by less expensive generating units. Thus increased DG reduces demand in the wholesale market. As demand moves down the supply curve, prices are reduced, as shown in the following illustrative supply curve:

Figure 1. Illustrative supply curve for New England showing the impacts of demand resources



A given quantity of DG will typically have a much greater downward impact on energy market prices during peak (or "high demand") periods as compared to non-peak periods[15]. Thus DG can have a material impact on the average wholesale energy price over a season or year even if it only operates primarily during peak periods. It doesn't have to run 24 hours a day to produce this benefit.

Wholesale electric capacity prices.

DG resources also have the potential to reduce wholesale electric capacity prices. DG resources reduce peak demand and, therefore, reduces the installed capacity requirement and hence the quantity of generation capacity. Thus, similar to its effect on the energy market, DG resources shift the capacity demand curve downward and result in a lower capacity price. This study does not analyze those capacity market impacts.

Potential Impact of DG on Air Emissions

DG has the potential to reduce emissions associated with electricity generation from the grid. The quantity of emissions from grid related electricity generation is directly related to the quantity and mix of that electricity generation. Therefore, a reduction in load on the grid due to the addition of DG resources will result in a reduction in the quantity of emissions produced by grid generation. Since some DG resources produce emissions it is important to analyze the net impact of DG resources on emissions, i.e. reduction in emissions from grid generation minus DG emissions.

Potential Quantities of DG

Generally, the more DG resources are introduced, the greater will be their impacts. The intent of this analysis was to identify the impacts that would result from quantities of DG resources that could be implemented by 2020 in response to state and other policies that remove barriers and encourage cost-effective DG. For solar PV, the level of MW modeled in 2020 was based on a 250 MW goal for the next 10 years established by the Governor of Massachusetts.[16] While that PV goal was set for the year 2017, it was used here for 2020 without attempting to estimate an increase for the intervening 3 years. For CHP, since no comparable goal has been established for Massachusetts, a separate study was undertaken for MTC by KEMA to make estimates of market potential for CHP[17]. Based on the range of estimates in that report, 750 MW was selected as the level of CHP to be modeled.

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[15] The off-peak and on-peak periods are defined based on the ISO-NE definitions: on-peak hours are 7 a.m. to 11 p.m. on weekdays and off-peak hours are 11 p.m. to 7 a.m. on weekdays and all hours on weekends.

[16] Governor Patrick Announces ... Plan to Boost Clean Energy, Jobs, Press Release, April 17, 2007: http://www.masstech.org/dg/2007-04-17-Gov-Patrick-PV-250MW.pdf

[17] Market Potential of Combined Heat and Power in Massachusetts, prepared by KEMA for Massachusetts Technology Collaborative, March 2008: http://www.masstech.org/dg/2008-03-MA-CHP-Market-KEMA.pdf

2. Methodology

A. Scenario Analysis

Impacts of DG resources on the wholesale electricity prices in New England are estimated by simulating the electric system for every hour of the year 2020 under different scenarios in which incremental DG resources are added to the system and compared to a Reference case in which no incremental DG resources are added. The Reference Case represents a scenario in which no investment is made in incremental DG resources. The DG cases represent scenarios in which incremental DG resources are added to the system. For the DG scenarios, no other changes are made to the system.

The DG resources modeled in this analysis were photovoltaics (PV) and combined heat-and-power (CHP). These units do not bid into the energy market and essentially operate as load-reduction resources. These resources are modeled as supply-side resources that are modeled as must-run units with deterministic generation profiles and, therefore, act as load-reduction resources within the model.

Impacts of DG resources on wholesale electric market prices in New England are estimated by comparing hourly zonal clearing prices from the Reference Case with hourly prices from DG cases. The model used to simulate the regional electric system simulates conventional plant outages with a probabilistic Monte Carlo method that can have significant impacts on hourly prices. In order to account for this effect, ten iterations are simulated for each case. In each iteration, the outage profile for all units is the same across cases, i.e. each iteration for the Reference Case has the same outage profile as the corresponding iteration for the PV Case. For each iteration, the model simulates each hour of the year. This multiple-iteration method provides greater confidence in any differences between the Reference Case and DG cases than would be provided by a single iteration.

B. Wholesale Energy Market Impacts

The impacts of DG resources on the wholesale electric markets are estimated using Global Energy Decision's[18] Market Analytics forecasting model. The basic methodology involves comparing average hourly zonal prices forecast by the model for various time periods for the Reference Case with average hourly zonal prices for the DG cases. Similarly, the impact of DG resources on system emissions is also calculated.

Energy Market Simulation Model

The energy market price and emissions impacts are estimated by using Global Energy Decisions' Market Analytics market forecasting tool to simulate the operations of the regional electric grid. Market Analytics uses the PROSYM simulation engine to produce

[18] Formerly Henwood Energy Services, Inc.

optimized unit commitment and dispatch options. The model is a security-constrained chronological dispatch model that produces detailed and accurate results for hourly electricity prices and market operations. The basic geographic unit in PROSYM is a sub region of a control area, called a "transmission area." Transmission areas are defined in practice by actual transmission constraints within a control area. PROSYM uses highly detailed information on operating costs and chronological operating constraints (e.g. ramp rates and minimum up and down times) for generators and dispatches units economically to meet load and reserve requirements in each transmission area. Transmission paths between transmission areas allow generating units to be dispatched to meet load in other transmission areas if economic and if the transmission path is not congested. The model determines the market clearing price in each transmission area based on the marginal unit, or the last unit dispatched to meet load in that transmission area. PROSYM also calculates emissions based on unit-specific emission rates and generation.

For a more detailed description of Market Analytics and PROSYM, see Chapter 5, Section B of the AESC 2007 Report which is Appendix A to this report. (Appendices are presented separately).

Energy Market Model Topology

Market Analytics represents load and generation zones at various levels of aggregation. Assets within the Market Analytics model, including physical or contractual resources such as generators, transmission links, loads and transactions, are mapped to physical locations which are then mapped to Transmission Areas. Multiple Transmission Areas are linked by transmission paths to create Control Areas. For this study, New England is represented by 11 Transmission Areas that are based on the 13 load zones as defined by ISO New England for the 2006 Regional System Plan.[19,20] Neighboring regions that are modeled in this study are New York, Quebec, and the Maritime Provinces. Areas outside of New England are represented with a high level of zonal aggregation to minimize model run time. The load and generation zones as they were modeled are presented in Table 1 and Figure 2.

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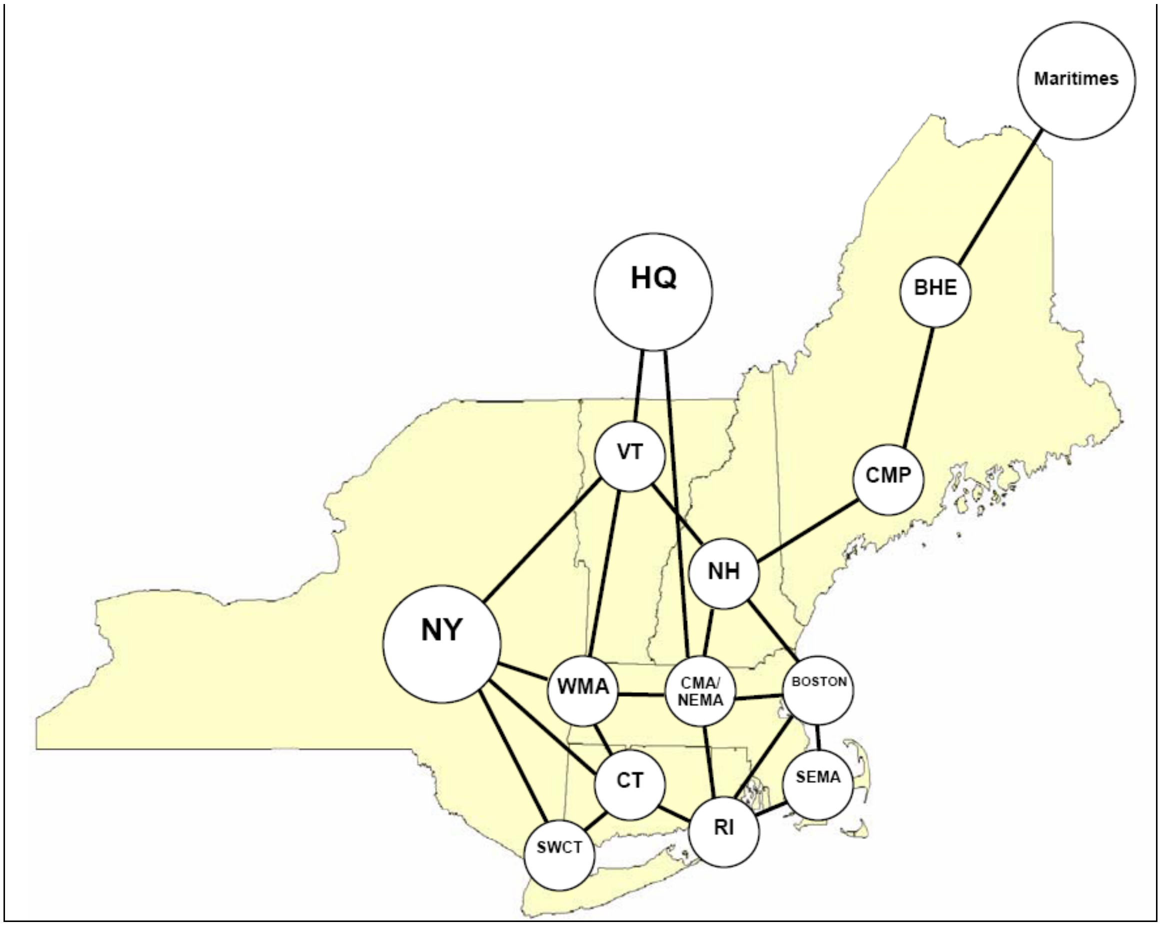
19 ISO New England, *2006 Regional System Plan*, 2006. http://www.isonewengland.com/trans/rsp/2006/rsp06_final_public.pdf

20 Market Analytics combines western and central Maine/Saco Valley, New Hampshire and southeastern Maine to form ME-CMP and includes Norwalk/Stamford in CT-SW.

Table 1. Zonal topology used to model the Northeast electric system

Region	Zone Designation	Description
New England	BHE	Northeastern Maine
	ME-CMP	Southeastern Maine and western and central Maine/Saco Valley, New Hampshire
	NH	Northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine
	VT	Vermont/southwestern New Hampshire
	Boston	Greater Boston, including the North Shore
	CMA/NEMA	Central Massachusetts/northeastern Massachusetts
	WMA	Western Massachusetts
	SEMA	Southeastern Massachusetts/Newport, Rhode Island
	RI	Rhode Island/bordering MA
	CT	Northern and eastern Connecticut
	CT-SW	Southwestern Connecticut including Norwalk/Stamford
New York	NY	NY-ISO control area
Quebec	HQ	Hydro Quebec control area
Maritimes	M	Maritimes control area

Figure 2. Map showing the zonal topology used to model the Northeast electric system



The zones used in the model differ from the Standard Market Design (SMD) zones for which hourly prices are reported within ISO New England. Table 2 shows how the zones differ based on allocation of load. Results presented in this report for the entire state of Massachusetts are calculated by applying the allocation factors shown in Table 2 to the zonal results produced by the model.

Table 2. Load allocation factors for ISO New England. Percentages reflect the portion of each state's peak load located within each zone. Modeling zones serving Massachusetts load are shaded[21]

Modeling Zone	2006 RSP Subarea	SMD Load Zone	State	2006 Peak MW	State					
					CT	MA	ME	NH	RI	VT
BHE	**BHE**	ME	Maine	310			15.4%			
CMP	**ME**	ME	Maine	988			49.1%			
		NH	New Hampshire	57				2.5%		
	SME	ME	Maine	665			33.0%			
NH	**NH**	ME	Maine	50			2.5%			
		NH	New Hampshire	1,790				77.4%		
		VT	Vermont	70						6.7%
VT	**VT**	NH	New Hampshire	308				13.3%		
		VT	Vermont	902						86.2%
BOSTON	**BOSTON**	NEMA/Boston	Massachusetts	5391		**42.9%**				
		NH	New Hampshire	79				3.4%		
CMA/NEMA	**CMA/NEMA**	WCMA	Massachusetts	1671		**13.3%**				
		NH	New Hampshire	79				3.4%		
WMA	**WMA**	CT	Connecticut	72	1.0%					
		WCMA	Massachusetts	1,929		**15.4%**				
		VT	Vermont	74						7.1%
SEMA	**SEMA**	SEMA	Massachusetts	2811		**22.4%**				
		RI	Rhode Island	149					8.0%	
RI	**RI**	SEMA	Massachusetts	759		**6.0%**				
		RI	Rhode Island	1706					92.0%	
CT	**CT**	CT	Connecticut	3580	49.4%					
SWCT	**SWCT**	CT	Connecticut	2,340	32.3%					
	NOR	CT	Connecticut	1,260	17.4%					

21 Based on Table 3-6 of ISO New England 2006 Regional System Plan

3. Reference Case

A. Modeling Inputs and Assumptions

The Reference Case represents a scenario for the year 2020 with no incremental DG resources added to the system. Input assumptions for the Northeast electricity market are based on inputs developed for the 2007 Avoided Energy Supply Cost (AESC) study completed by Synapse in August, 2007[22]. The inputs developed for the AESC study were reviewed by members of the study's sponsor group which included representatives from most of the electric and gas utilities in New England as well as state environmental and energy agencies and consumer advocacy groups.

The inputs developed for the AESC study include existing generation resources, planned new resources, generic new renewable resources to meet renewable portfolio standards, and additional new generic conventional capacity to meet future load growth. These inputs also include the following:

- Fuel price forecasts
- Emission allowance price forecasts
- Transmission links between transmission areas
- Ancillary services markets
- Generator bidding strategies

The AESC study inputs include load forecasts that are consistent with the ISO-NE 2007 CELT Report. The 2007 CELT Report presents the ISO's load forecast for the next ten years (2007-2016). The AESC study projected load for five more years beyond 2016 based on the compound annual growth rate for the 2007-2016 period. Table 3 below shows the zonal loads for Massachusetts in 2020.

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22 Synapse Energy Economics, *Avoided Energy Supply Costs in New England*, prepared for the Avoided Energy Supply Component Study Group, 2007. Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2007-08.AESC.Avoided-Energy-Supply-Costs-2007.07-019.pdf

Table 3. Total energy and summer peak forecast by modeling zone for Massachusetts for 2020

Zone	Energy (GWh)		Peak	
	Total	In MA	Total	In MA
Boston	29,864	29,432	6,810	6,712
CMA/NEMA	9,527	9,097	2,180	2,082
SEMA	15,887	15,087	3,628	3,445
WMA	11,522	10,712	2,517	2,340
RI	13,385	4,121	3,074	947
Total[23]	80,185	68,450	18,209	15,525

This load forecast includes DSM measures that were in existence prior to 2007 and does not include any forecast for additional DSM measures. This was consistent with the purpose of the AESC study which was to estimate avoided costs of new DSM measures. However, there is the potential that estimating the impacts of DG resources with a load forecast that does not assume any incremental energy efficiency may overstate the impacts of DG. While this impact is likely not significant, further analysis of this issue is needed.

For a detailed description of the inputs discussed above, please see Chapter 5 of the AESC study which is included as Appendix A to this report.

B. Reference Case Results

Figure 3 below shows the average hourly prices[24] by month for all hours of the year for the Reference Case[25]. These prices reflect the seasonal load and fuel price patterns that are implicit in the inputs. Figure 3 also shows the average prices for the day and night periods. The difference between the day and night prices in each month reflects the seasonal differences in the energy price volatility. The average monthly price ranges from about $62/MWh in April to about $85/MWh in August.

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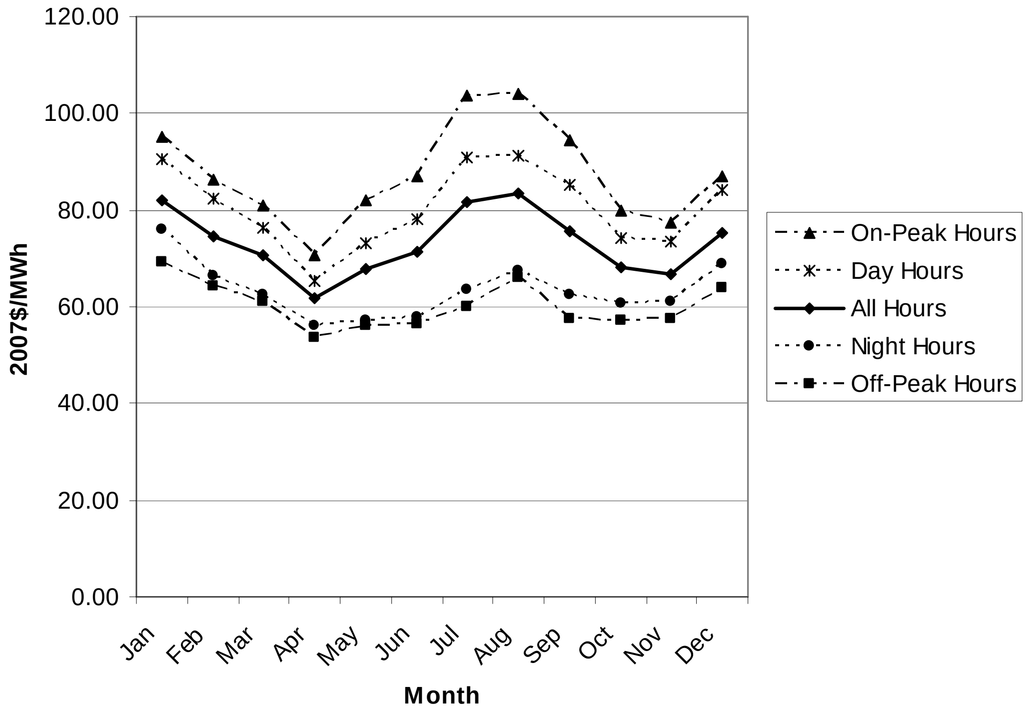
23 The total of the zonal peak demand values is non-coincident.

24 All cost values throughout the report are presented in 2007 dollars unless otherwise noted.

25 Due to the probabilistic nature of how the model simulates forced outage profiles for generators, in some hours the model is not able to meet load in some zones. In these hours in which there is "energy not served" (ENS), the market clearing price is set at the input price of energy not served which is generally a very high price. Theses extreme hours significantly increase the variability within the data and, therefore, reduce the confidence around the mean differentials between the Reference Case and the DG cases. Therefore, the results presented in this section exclude these hours. These extreme hours tend to occur with similar frequency in the Reference Case and DG cases, and, therefore, removing these hours does not have a dramatic impact on the average annual impact of DG resources on energy prices. The energy price results including the ENS hours are presented in Appendix C.

Figure 3. Average hourly wholesale electric prices by month and time period for Massachusetts (based on load-weighted average of the hourly prices for the four Massachusetts modeling zones)



Total wholesale electric costs are shown in Figure 4 below. The total wholesale electric costs represent the sum of the zonal prices multiplied by the hourly zonal loads for each month. The total wholesale electric costs for the study year are approximately $5.3 billion.

Figure 4. Total wholesale electric energy cost for Massachusetts by month

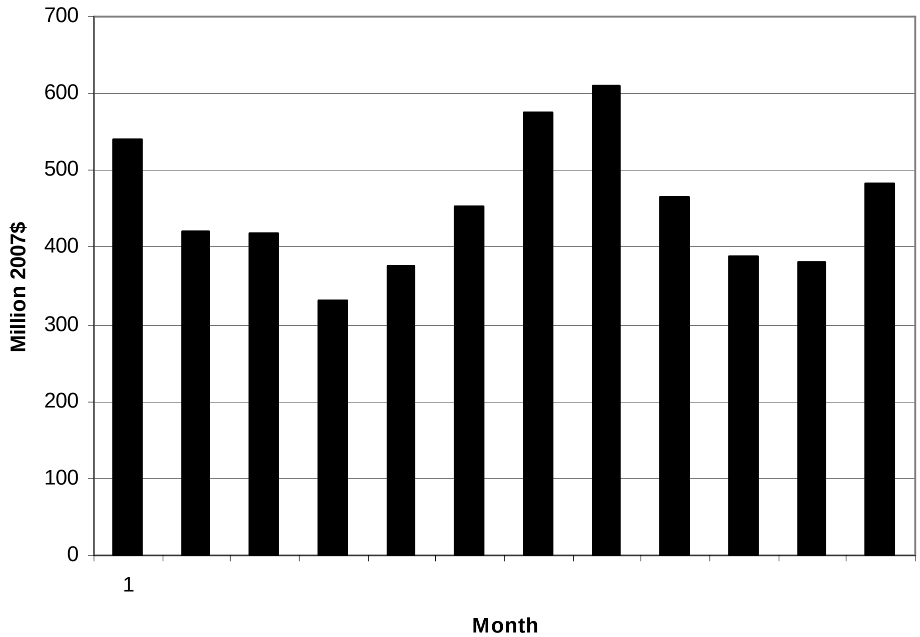


Table 4 shows the total regional emissions of CO_2, mercury, NO_x, and SO_2 from generation by control area for 2020. The absolute quantity of emissions varies by control area because of differences in the quantity and mix of generation.

Table 4. Total Reference Case emissions by type and control area for 2020

Control Area	CO_2 (000 Short Tons)	NOX (000 Short Tons)	SO2 (000 Short Tons)	Mercury (lbs)
ISO-NE	64,945	35.05	57.12	110
Maritimes	22,487	35.07	149.26	505
NYISO	55,107	26.80	48.08	331
Quebec	2,055	0.98	0.01	0
Total	144,593	97.90	254.47	947

4. PV Case

A. Modeling Inputs and Assumptions

Incremental PV Capacity Additions

The study modeled a single PV scenario, assuming an incremental 250 MW of installed PV. That incremental capacity is consistent with Governor Patrick's policy goal of 250 MW of new PV by 2017[26].

That PV capacity is only added to the modeling zones that include Massachusetts load. It is distributed among those zones based on the zonal load allocation factors presented in Table 2 above. Table 5 below shows the allocation of the 250 MW of PV capacity among the modeling zones.

Table 5. Nameplate PV capacity by modeling zone (MW)

Modeling Zone	Scenario	
	Reference Case	PV Case
BHE	0	0
BOSTON	0	107
CMA/NEMA	0	33
CMP	0	0
CT	0	0
NH	0	0
RI	0	15
SEMA	0	56
SWCT	0	0
VT	0	0
WMA	0	38
ISO-NE Total	**0**	**250**

PV Output Profile

PV resources are modeled with a generation profile that was developed for this analysis with the help of New Energy Options (NEO). The profile is a composite profile based on two hourly profiles developed by NEO. NEO developed two profiles for a simulated typical PV system based on meteorological data from the National Renewable Energy Laboratory's (NREL) Typical Meteorological Year 2 (TMY2)[27] data for sites at Boston

[26] Governor Patrick Announces ... Plan to Boost Clean Energy, Jobs, Press Release, April 17, 2007: www.masstech.org/dg/2007-04-17-Gov-Patrick-PV-250MW.pdf

[27] The NREL website describes the Typical Meterological Year 2 data sets as follows:

and Worcester, MA. Appendix A describes the model and assumptions used to develop these profiles. These profiles represent hourly PV production as a ratio of nameplate PV capacity. The composite profile was developed by averaging the production ratios from the Boston and Worcester profiles in each hour. Table 6 below shows the monthly capacity factor associated with this profile.

Table 6. PV capacity factor by month

Month	Capacity Factor
1	12.8%
2	16.3%
3	17.8%
4	17.8%
5	18.4%
6	18.2%
7	18.7%
8	18.3%
9	17.1%
10	15.9%
11	11.8%
12	11.1%
Entire Year	16.2%

This profile was developed with consideration of the following factors:

- Load and PV production are both strongly correlated with meteorological variables such as temperature and solar irradiance.
- PV production profiles at different sites within a relatively small region such as southern New England are highly correlated, yet there is some geospatial diversity in the regional PV resource.
- Production from a solar PV resource has a fairly predictable diurnal pattern, however, in a typical year, the PV production profile can exhibit a significant amount of variation in the diurnal profile from day to day.

The TMY2s are data sets of hourly values of solar radiation and meteorological elements for a 1-year period. Their intended use is for computer simulations of solar energy conversion systems and building systems to facilitate performance comparisons of different system types, configurations, and locations in the United States and its territories. Because they represent typical rather than extreme conditions, they are not suited for designing systems to meet the worst-case conditions occurring at a location.

The TMY2 data sets and manual were produced by the National Renewable Energy Laboratory's (NREL's) Analytic Studies Division under the Resource Assessment Program, which is funded and monitored by the U.S. Department of Energy's Office of Solar Energy Conversion.

For more information see the TMY2 User's Manual at: http://rredc.nrel.gov/solar/pubs/tmy2/

The PV profile that is used in this study lacks the inherent source correlation that a simulated PV power data set derived from the same years as the load data might have. This is because we did not have an irradiance data set for the same period for which the hourly load profiles that are used in the model are based on.[28] Without having a temporally matched irradiance data set, the correlation between load and PV production may be suspect. However, analysis of the historical correlation between load and PV production from actual PV facilities in Massachusetts suggests that the correlation between the simulated PV and load profiles used in this study is reasonably consistent with the actual relationship between load and PV in the region. More importantly, the PV production data set that was developed for this study does exhibit some of the natural diurnal variability in the PV resource and it therefore shows some of the real highs and lows that an average profile, such as the PV production profile developed for the ISO New England Scenario Analysis, would not accurately capture[29].

B. Results

Impacts on Wholesale Electric Energy Prices and Annual Energy Costs

The results of the modeling indicate that 250 MW of PV would have a measurable impact on wholesale electric energy prices in Massachusetts. The modeled PV resource significantly reduces wholesale electric prices in many hours during the year. When averaged over the entire year the impact is -0.4%

First, the generation of PV power reduces the annual power costs for the owners of the PV resources by reducing the quantity of electricity they purchase. Valued at wholesale market prices that reduction is worth $37 million in 2020.[30]

Second, this PV generation benefits all electricity consumers, as will be discussed below in greater detail by reducing wholesale electric energy market prices in MA, and throughout New England. That reduction in prices translates into a reduction in the total

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[28] The hourly load profiles developed by Global Energy Decisions and provided with the Market Analytics model represent a typical year's load shape and are developed based on historical load data from 2000-2005. These profiles are developed to represent a "normal" weather year while maintaining a realistic amount of load diversity in the load shape. Similarly, the TMY2 dataset represents a typical meteorological year. The TMY2 dataset, however, is developed based on historical meteorological data from the 1961-1990 period.

[29] ISO New England conducted its "New England Electricity Scenario Analysis" to explore the economic, reliability, and environmental impacts of various future resource scenarios. This analysis include a set of renewable resources which included PV. The PV profile developed for this analysis consisted of a single 24-hour profile for each month that is based on the average hourly output of a simulated PV resource.

[30] This is the wholesale value of avoided costs due to the PV generation by retail customers, and is not the primary focus of this report.

cost of wholesale electric energy to all MA energy users, relative to the Reference Case, of $23 million[31].

That reduction in wholesale electric energy costs is attributable to the energy generated by the PV resources that displaces purchases from the wholesale market. When divided by the generation from those PV resources, that impact can be expressed as $63.68 of savings to Massachusetts energy users in 2020 for every MWh of PV generation in Massachusetts. (This is $23 million divided by annual PV generation of 355,600 MWh).

Figure 5 shows the average hourly wholesale electric price differential between the PV Case and the Reference Case by month and time period[32].

Figure 5. Average hourly wholesale electric price differential by month for all Massachusetts modeling zones in the PV Case relative to the Reference Case

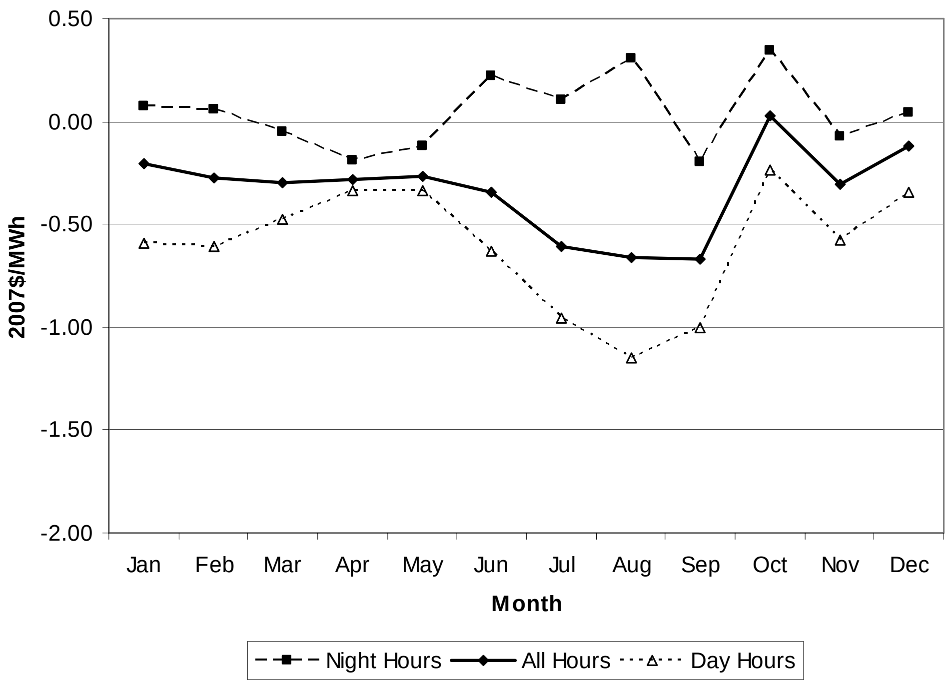


Figure 6 shows the savings in wholesale energy costs to all MA energy users due to the market price impacts shown in Figure 5.[33]

[31] The gross energy market cost savings attributable to the market price impacts of demand resources is calculated by multiplying the average price differential in each scenario by the net load (not including the demand resource savings) in each scenario.

[32] The day-time and night-time periods are defined based on the PV profile and the hours in each month in which the PV resource is producing power. The daytime period includes all hours of the day in which the PV resource is producing power while the nighttime period includes all hours in which the PV resource is not producing power.

[33] The average price impact is a slight increase in one month, October, which could be an anomaly attributable to outage patterns or other sources of variability in the model. As described above, multiple iterations with different outage profiles were simulated.

Figure 6. Total energy market cost savings attributable to the price differential between the PV Case and the Reference Case by month for Massachusetts

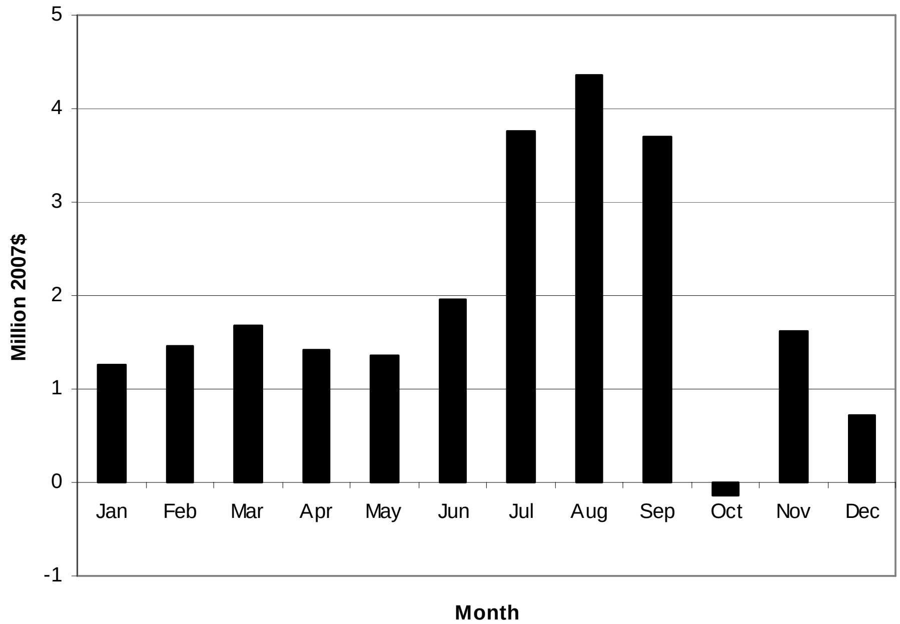


Table 7 presents a side-by-side comparison of the energy price differentials shown in Figure 5 and the statistical significance for each series. Table 9 also shows the annual percent differential in the wholesale electric energy price relative to the Reference Case.

Table 7. Average hourly wholesale electricity price differential ($/MWH) by month and time period for Massachusetts relative to the Reference Case. Values that are statistically significant within a 95% confidence interval are shown in bold

	PV Case		
Month	All Hours	Night	Day
Jan	-0.20	0.07	-0.59
Feb	-0.27	0.06	**-0.61**
Mar	-0.30	-0.05	-0.48
Apr	-0.28	-0.19	-0.33
May	-0.27	-0.12	-0.34
Jun	-0.34	0.22	-0.63
Jul	-0.61	0.10	-0.96
Aug	-0.66	0.31	**-1.15**
Sep	-0.67	-0.19	**-1.01**
Oct	0.03	0.34	-0.24
Nov	-0.30	-0.08	-0.57
Dec	-0.12	0.04	-0.35
Annual	**-0.33**	0.04	**-0.62**
Annual (%)	**-0.4%**	0.1%	**-0.8%**

Figure 7 shows the difference between the wholesale electric prices in the Reference Case and the PV Case as well as the PV output in the PV Case for an illustrative day in August of the modeled year. This figure illustrates the price reduction effect that PV has on hourly prices. The magnitude and timing of this effect varies from day to day. In some hours, it is possible for PV generation to drive prices up due to chronological constraints of generators at or near the margin. For example, PV generation may displace a unit in the late afternoon that may not be operating at full capacity. If this unit is needed to meet load in subsequent hours it may not be available due to a minimum down-time constraint and a more expensive unit may need to be dispatched.

Figure 7. Illustrative day - Hourly wholesale electric prices ($/MWh) for the Reference Case and PV Case and PV output (MW) from a single iteration for an illustrative day in August in the Boston modeling zone

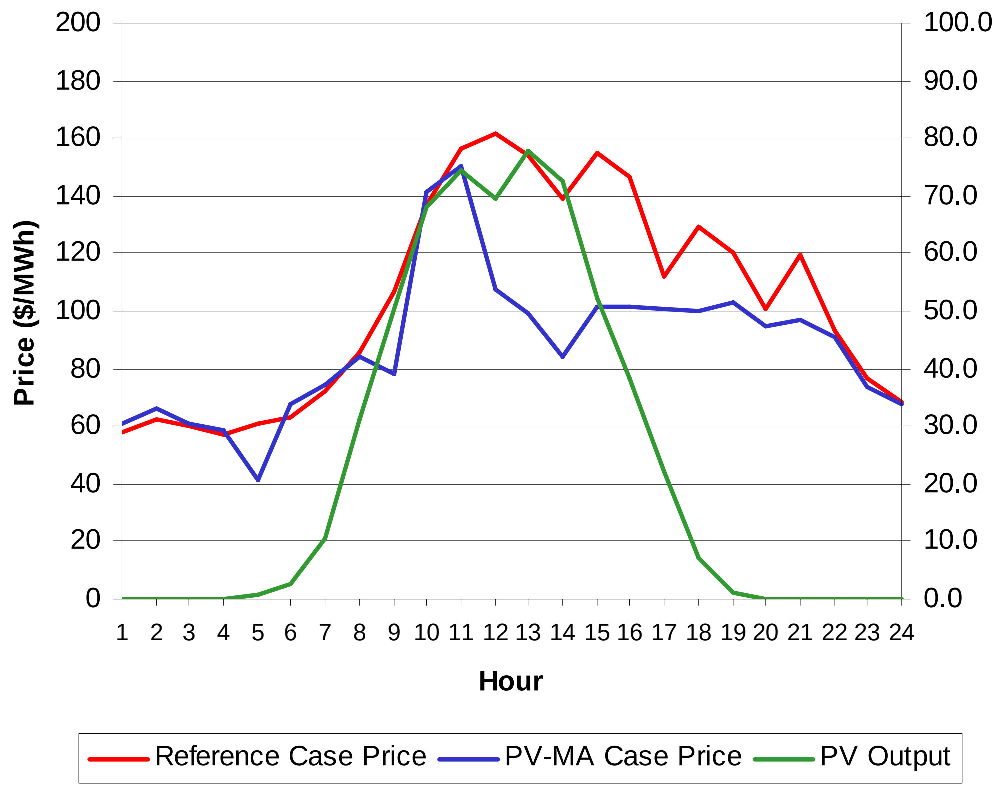
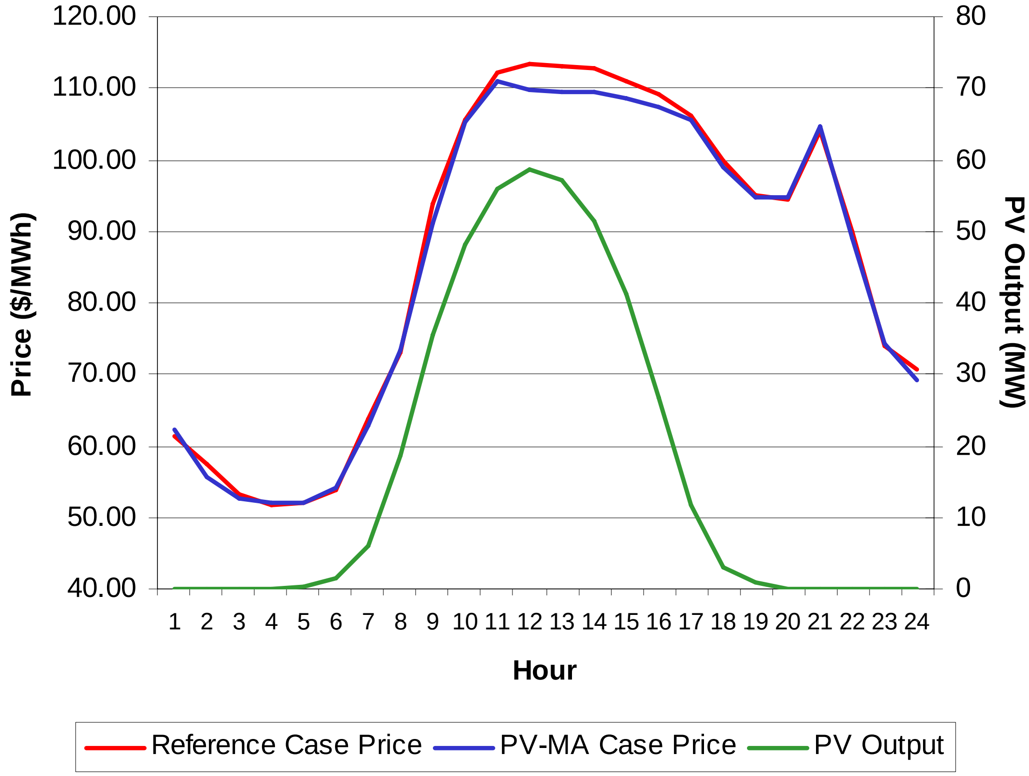


Figure 8 illustrates the effect shown in Figure 9 averaged over all days of August and ten iterations. Although the average impact is not as dramatic, there is a clear difference between the average hourly prices for the Reference Case and PV Case in August that coincides with the PV production profile. The price impact lags slightly behind the timing of the PV profile; this is likely due to the chronological operating constraints of the displaced capacity (i.e. ramp rates, minimum up and down times).

Figure 8. Illustrative Month - Average hourly wholesale electric prices ($/MWh) for the Reference Case and PV Case and average PV output (MW) from ten iterations for the entire month of August in the Boston modeling zone



Environmental Impacts

Table 8 shows the reductions in emissions associated with generation sold into the wholesale markets due to incremental PV generation under the PV Case.

Table 8. Reduction in emissions under the PV Case as a percent of Reference Case emissions

Control Area	CO2	NOX	SO2	Mercury
ISO-NE	0.1%	0.1%	0.1%	0.1%
Maritimes	0.1%	0.1%	0.0%	0.0%
NYISO	0.1%	0.1%	0.3%	0.1%
Quebec	0.1%	0.0%	0.0%	n/a
Total	0.1%	0.1%	0.1%	0.1%

C. Discussion

The results of this analysis suggest that PV resources can have an impact on wholesale electric energy prices, producing an average annual reduction in prices of about $0.33 per

MWh or -0.4%. While that price reduction may seem small compared to prices of around $80 per MWh, it is impressive given the scale of the PV investment that produced it, i.e. 250 MW and 356 GWH. That level of PV is 1.6% and 0.5% of the Reference Case wholesale market peak and energy demand in Massachusetts, respectively.

The seasonal correlation between the PV price impacts and market prices suggests that PV resources have the greatest impact during the summer months when prices are high, volatility is high, and PV production is at relatively high. This is primarily due to the fact that the high price summer periods are generally periods of high load. When load is high, the supply curve tends to be steeper, and, therefore, load reduction due to PV has a greater impact than during periods when load is relatively low and the supply curve is relatively flat. This effect is evident in the results for the month of April. In the model April is the month with the lowest system load and the highest load factor. Although total production from the PV resource in April is only slightly less than during the most productive month, July, the incremental cost difference at the margin is smaller in April than it is in July[34].

This study does have some limitations which raise further questions regarding the market price impacts of PV that may be examined in future work. These questions include the following:

- Would simulations with a greater number of iterations provide more clarity regarding the seasonal nature of the price impacts associated with PV?
- What impact would additional incremental energy efficiency have on the market price impact that is directly attributable to PV resources? This analysis was conducted in conjunction with the analysis of the price impacts of CHP as discussed later in this report, but this sensitivity was not conducted in conjunction with PV.
- How would the modeled impacts of PV change when the load and PV profiles are both derived from a temporally matched data set in which the meteorological factors that affect both variables are the same? This could be done by using PV and load profiles from the same historical year.
- How will PV resources affect the amount of capacity added to the system to meet load growth and will any change in the mix due to the additions of PV affect the market price impact that is directly attributable to PV resources? Installation of PV resources at the level modeled in this study will likely displace conventional resources that would otherwise have been needed for capacity purposes. However, for the PV Case in this study, the capacity mix was not changed. This factor is discussed further later in this report.

[34] The relatively small quantity of PV in this case makes it difficult to discern its price impacts in certain hours.

5. CHP Cases

A. Modeling Inputs and Assumptions

Incremental CHP Capacity Additions

In order to estimate the market price impacts of CHP resources, a CHP Case was simulated in which 750 MW of CHP capacity was added to the Reference Case resource mix in the in 2020. This level of CHP penetration is based on analyses conducted by KEMA.

KEMA's penetration model first estimated paybacks over time for a typical CHP plant for various commercial, institutional and industrial segments and plant sizes, based on current costs and heat rates for various gas-fired CHP systems, along with expected improvements over time, and based on expected electricity and natural gas prices. These payback calculations were also based on assumptions of CHP capacity factors and rates of utilization of the thermal output for each market segment and plant size. KEMA then used market penetration curves to determine the penetration of CHP based on the expected payback for each year within each segment and plant size. A complete presentation of KEMA's market penetration methodology, assumptions and data are available in its report.[35]

A number of scenarios were presented in the KEMA report for the 12-year period 2009 through 2020 (as well as later years), including a "base case" estimate of approximately 350 MW and an "achievable policy" scenario of approximately 800 MW. Based on the range of estimates in that KEMA report, 750 MW was selected as a policy scenario to model the impacts on the wholesale electricity market. The KEMA report also provides an estimate of electricity generating profiles for the overall mix of CHP for each hour of a typical 7-day week for each of three seasons (winter, summer and shoulder).

CHP resources were represented in the model as generating units with operating profiles that represent the aggregate CHP generation profile based on the CHP resource mix as determined by the CHP penetration model developed by KEMA. Two CHP resource types were modeled for the year 2020 in this analysis:

- price-responsive CHP (PR-CHP). CHP units that will be dispatched to meet electrical load in 2020 based in response to real-time prices; and

- non-price responsive CHP (NPR-CHP). CHP that is expected to operate on a fixed schedule, or to follow thermal load, without consideration of any variations in the price of power,[36]

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[35] Market Potential of Combined Heat and Power in Massachusetts, prepared by KEMA for Massachusetts Technology Collaborative, March 2008: http://www.masstech.org/dg/2008-03-MA-CHP-Market-KEMA.pdf

[36] See Figure 11 below for an illustration of the hourly generating pattern of this CHP.

These resources will be further defined in the following sections.

The 750MW of CHP was distributed among the modeling zones based on total load by zone. Table 9 shows this distribution.

Table 9. CHP capacity (MW) in 2020 modeled in each modeling zone

Modeling Zone	CHP Type		
	Non-Price-Responsive	**Price-Responsive**	**Total**
BHE	0	0	0
BOSTON	220	102	322
CMA/NEMA	68	32	100
CMP	0	0	0
CT	0	0	0
NH	0	0	0
RI	31	14	45
SEMA	115	53	168
SWCT	0	0	0
VT	0	0	0
WMA	79	37	115
ISO-NE Total	**512**	**238**	**750**

The addition of this magnitude of CHP resources would likely apply downward pressure on the demand for new capacity (including reduction in the need for Renewable Portfolio Supply resources). Therefore, the capacity mix was adjusted by removing some generic conventional and renewable resources consistent with the methodology used to develop the capacity mix in the Reference Case[37].

Table 10 shows the generic and renewable capacity that was removed from the regional resource mix in the CHP Case.

[37] See Appendix A: Details from AESC 2007 Report.

Table 10. Generic and renewable capacity (MW) removed from the Reference Case resource mix for the CHP Case in 2020

Zone	Gas CTs	Gas CCs	Wind [38]	Biomass	Total
BHE	0	0	0	0	0
BOSTON	100	0	0	0	100
CMA/NEMA	100	0	0	0	100
CMP	0	0	0	0	0
CT	100	0	0	0	100
NH	100	0	50	0	113
RI	100	0	0	0	100
SEMA	100	0	0	0	100
SWCT	100	0	0	0	100
VT	0	0	0	0	0
WMA	0	0	0	40	40
ISO-NE	700	0	50	40	753

CHP Profiles

CHP resources added to each modeling zone in Massachusetts are represented with two types of units with operating characteristics representative of the two modeled operating modes (price-responsive and non-price-responsive). In each zone, the CHP capacity for each CHP type is represented for modeling purposes as a single unit that represents the aggregate CHP resource.

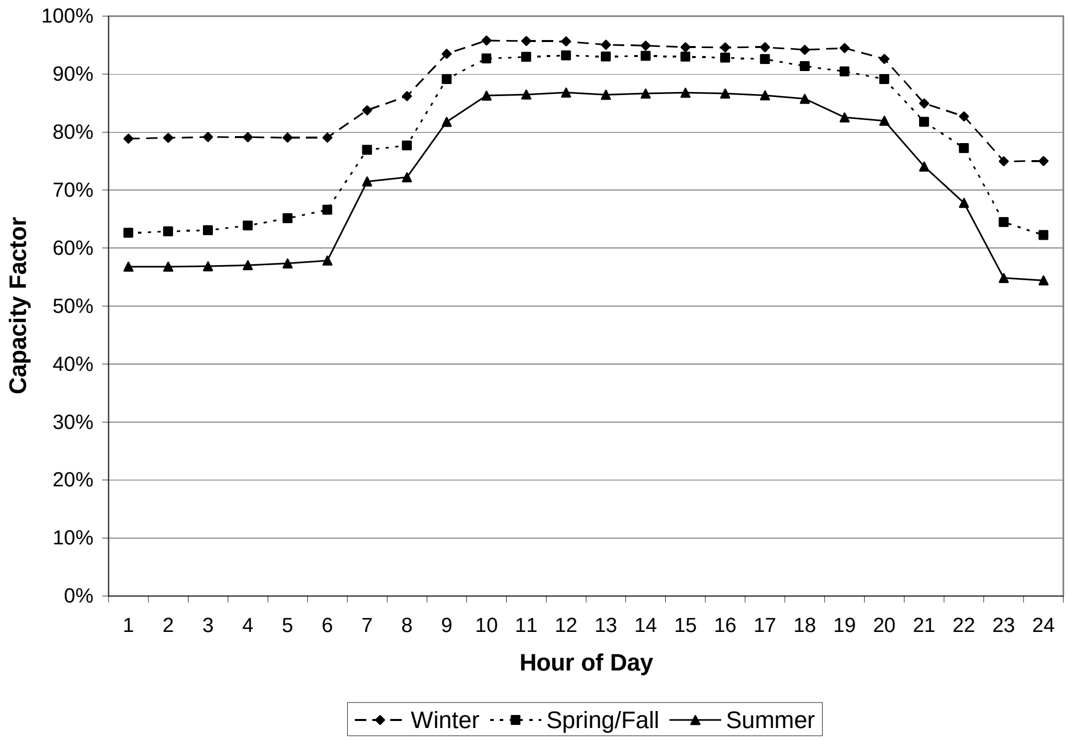
The aggregate generation profiles for each CHP type are described below.

Non-Price-Responsive CHP Profile.

The generation profiles for NPR-CHP resources developed by KEMA. Figure 9 shows the aggregate seasonal generation profiles for the NPR-CHP units added to the model.

[38] Wind capacity is shown as nameplate capacity, however, the total capacity includes an adjustment to account for the capacity credit of wind which was assumed to be 26%.

Figure 9. Aggregate daily generation profiles for NPR-CHP units by season



Price-Responsive CHP Profile

Price-responsive CHP resources (PR CHP) were modeled as "price stations" that would be dispatched by their owners based upon a "strike price" that represents the cost incurred by their owner to generate electricity from these CHP units. When the market price of electricity is below the strike price, the owner will purchase electricity from their retail supplier. When the market price for electricity is above the strike price, the owner will generate from the CHP. This mode of operation is expected to be more common in 2020 that it is today.

The strike price is a function of the fuel cost to the CHP owner, the thermal efficiency of the CHP unit, and variable operating cost. The strike price was calculated based on the following equation:

$$\left(HV_{Electric} / Efficiency_{Electric}\right) \times \left(1 - Efficiency_{HR}\right) \times FuelCost + MntCost$$

Where:

$HV_{Electric}$ is the heat value of electricity, which is 3412 Btu/kWh;

$Efficiency_{Electric}$ is the electric conversion efficiency of the CHP generator which is assumed to be 33%;

$Efficiency_{HR}$ is the heat recovery efficiency of the CHP unit which is assumed to be 32%;

FuelCost is the retail cost of natural gas to the CHP owner in $/MMBtu; and,

MntCost is the maintenance cost of the CHP unit in $/MWh.

This equation yields a retail strike price of $0.107/kWh based upon a retail gas price of $13.17/MMBtu[39] and a maintenance cost of $0.015/kWh. A wholesale strike price was derived from this retail strike price and input into the simulation model. The wholesale strike price excludes the various adders reflected in retail prices, including T&D costs, capacity costs, and a retail adder. Removing those adders resulted in a wholesale strike price of$0.067/kWh or $67/MWh[40].

Maintenance and Forced Outages

Maintenance and forced outages were simulated for each CHP unit. For NPR-CHP units, maintenance outages were incorporated in the aggregate generation profile based on a weighted average of maintenance days per season by sector such that the total maintenance rate was about 2%[41]. For PR-CHP units an explicit maintenance rate of 2% was input into the model and maintenance outages were scheduled with the model's maintenance algorithm. Unplanned, forced outages were represented with a forced outage rate of 2.5% for both NPR-CHP and PR-CHP units. The model uses a probabilistic method to simulate random forced outages based on the input forced outage rate. The maintenance and forced outage rates used in this analysis are consistent with outage rates for existing CHP facilities of various sizes serving a variety of sectors[42].

Energy Efficiency

The load forecast used in the Reference Case is based on the ISO-NE CELT forecast which does not account for any new, incremental energy efficiency savings above the savings that are attributable to existing savings as of 2006.[43] However, in a case with a more realistic expectation regarding future levels of energy efficiency savings, the price impacts of CHP could be less than those measured relative to the Reference Case. Therefore, in addition to the Reference Case, the study simulated an Energy Efficiency

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[39] This retail gas price is a weighted average of the industrial and commercial retail gas prices for 2020, in 2007 dollars, used in the KEMA CHP Penetration model. It is consistent with the gas price forecasts in AESC 2007.

[40] Due to the nuances of the commitment and dispatch algorithm in the power system model, the wholesale strike price that was actually input into the model needed to be scaled up to $75/MWh to achieve the proper capacity factor for these price responsive units based on expected output with a calculated strike price of $67/MWh and the probability of hourly prices being above $67/MWh.

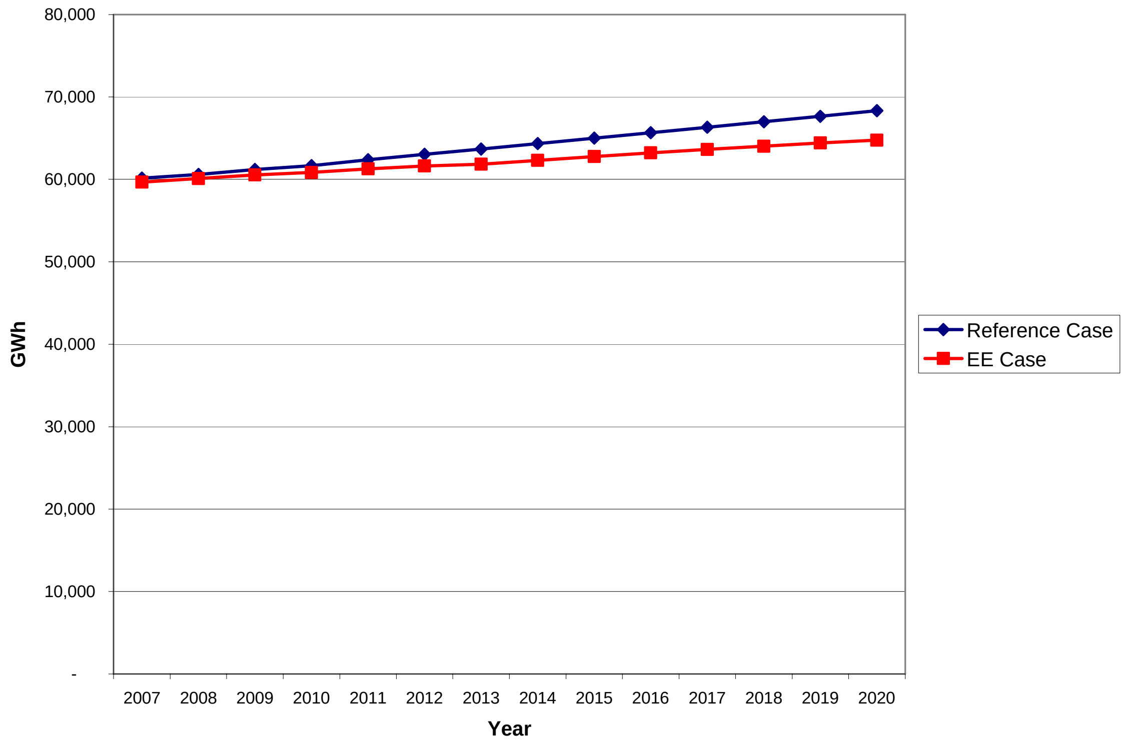
[41] For this analysis, it was assumed that CHP units serving commercial sectors would require seven days of maintenance in the month of May and CHP units serving industrial sectors would require seven days of maintenance in the month of July.

[42] These assumptions are based on outage rates for existing CHP facilities f from "DG Operational Reliability and Availability Database," ORNL-4000021456, January 2004, available at http://www.eea-inc.com/dgchp_reports/FinalReportORNLDGREL.pdf.

[43] The Reference Case did not include future efficiency because it was prepared for the AESC 2007 avoided cost study cited above.

Case (EE Case). The EE case has a load forecast that reflects anticipated or potential energy efficiency savings. The load forecasts under the Reference and EE cases are shown in Figure 10. The compound annual growth rate of electricity consumption (CAGR) is 1.0% in the Reference Case forecast. The growth rate is reduced to 0.6% in the EE Case.[44] The cumulative impact of energy efficiency savings in the EE Case results in a 5.2% reduction in demand in 2020 relative to the Reference Case forecast[45].

Figure 10. Comparison of the 2020 Massachusetts load forecasts used in the Reference Case and EE Case



In order to estimate the combined impacts of DG and EE on market prices, a "CHP+EE Case" was created. It uses the same 750MW of CHP as in the CHP Case plus the efficiency savings from the EE Case. In simulating these two cases the level and mix of wholesale capacity was adjusted in the same manner as described above for the CHP Case. Tables 11 and 12 show the generic and renewable capacity that was removed from the regional resource mix in the EE Case and the CHP+EE Case, respectively.

[44] This forecast was developed after communication with staff of the Massachusetts Division of Energy Resources (DOER).

[45] For this analysis, savings from DSM efforts were modeled with the same load factor as the overall load shape. In other words, load in each hour was reduced by the same percentage such that the total energy savings and the peak hour savings were both 5.2%. This is conservative with respect to EE impacts, since actual energy efficiency programs may place more emphasis on peak savings.

Table 11. Generic and renewable capacity (MW) removed from the Reference Case resource mix for the EE Case in 2020

Zone	Gas CTs	Gas CCs	Wind [46]	Biomass	Total
BHE	0	0	0	0	0
BOSTON	100	0	0	0	100
CMA/NEMA	0	300	0	0	300
CMP	0	0	0	0	0
CT	100	0	0	0	100
NH	100	0	50	0	113
RI	100	0	0	0	100
SEMA	100	0	0	0	100
SWCT	0	0	0	0	0
VT	0	0	0	0	0
WMA	0	0	0	40	40
ISO-NE	500	300	50	40	853

Table 12. Generic and renewable capacity (MW) removed from the Reference Case resource mix for the CHP+EE Case in 2020

Zone	Gas CTs	Gas CCs	Wind	Biomass	Total
BHE	0	0	0	0	0
BOSTON	200	0	0	0	200
CMA/NEMA	100	300	0	0	400
CMP	0	0	50	0	13
CT	100	300	0	40	440
NH	100	0	50	40	153
RI	100	0	0	0	100
SEMA	100	0	150	0	139
SWCT	100	0	0	0	100
VT	0	0	50	0	13
WMA	0	0	0	40	40
ISO-NE	800	600	300	120	1598

B. Results

Impacts on Wholesale Electric Energy Prices and Annual Energy Costs

The results of the modeling indicate that 750 MW of CHP would have a measurable impact on wholesale electric energy prices in Massachusetts. The modeled CHP resource significantly reduces wholesale electric prices in many hours during the year. This CHP generation benefits electricity consumers by reducing wholesale electric energy market prices in Massachusetts, as well as throughout New England. The impact of market price reductions accrues mostly to "non-participants" who do not own DG. This section

[46] Wind capacity is shown as nameplate capacity, however, the total capacity includes an adjustment to account for the capacity credit of wind which was assumed to be 26%.

summarizes the reduction in prices for each scenario, as well as the resulting reduction in the total cost of wholesale electric energy to Massachusetts energy users.

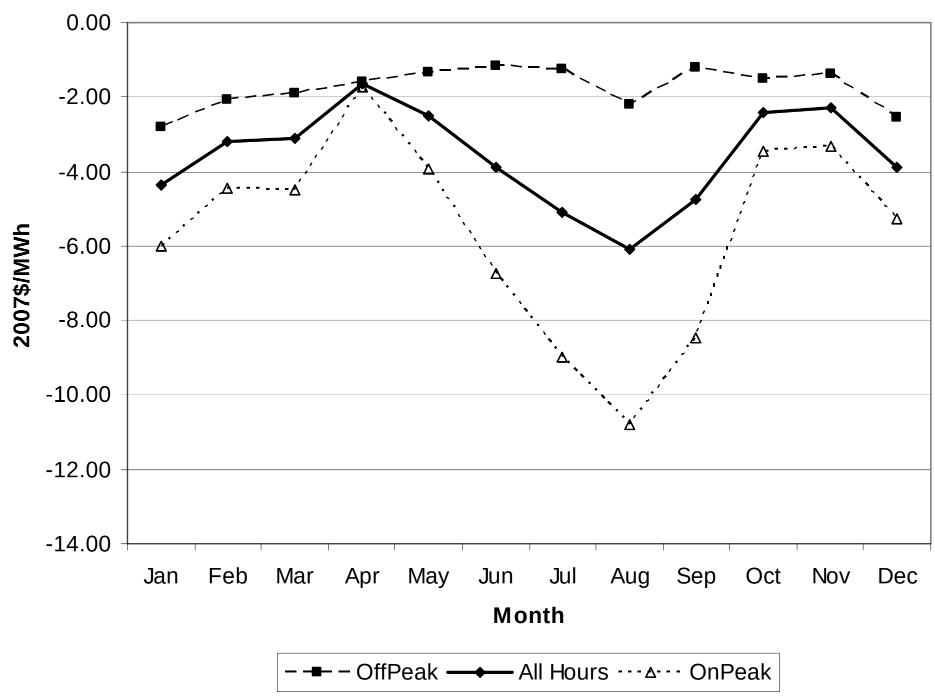
The results are presented below in the following sections:

- Impacts of CHP Compared to Reference Case
- Impacts of Energy Efficiency
- Impacts of the Combined Case - CHP + EE
- Incremental Impacts of Combined CHP+EE Case Compared to EE Case.

Impacts of CHP Compared to Reference Case

The modeled CHP resource significantly reduces wholesale electric prices in many hours during the year. Figure 13 shows the average hourly wholesale electric price differential between the CHP Case and the Reference Case by month and peak period[47]. The impact, when averaged over the entire year, is -4.9% in the CHP Case.

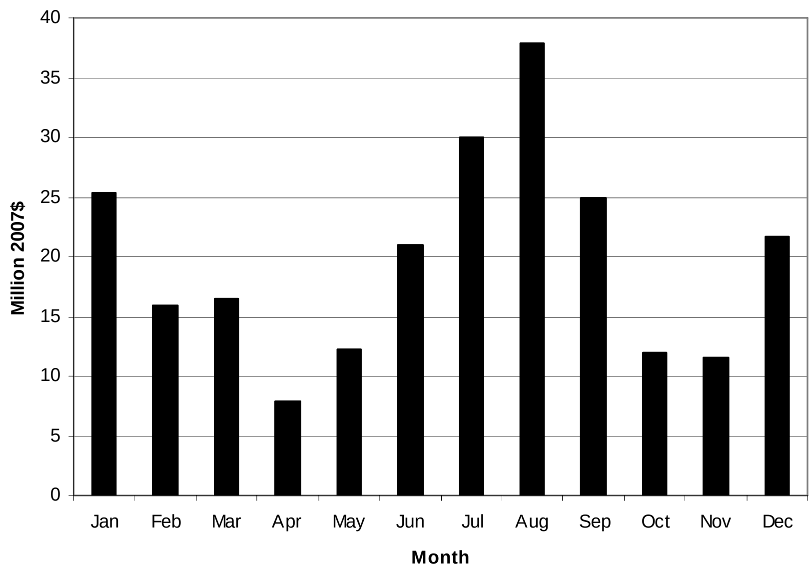
Figure 13. Average hourly wholesale electric energy price differential by month and peak period for Massachusetts in the CHP Case relative to the Reference Case



[47] The off-peak and on-peak periods are defined based on the ISO-NE definitions: on-peak hours are 7 a.m. to 11 p.m. on weekdays and off-peak hours are 11 p.m. to 7 a.m. weekdays and all hours on weekends.

This CHP generation benefits electricity consumers by reducing wholesale electric energy market prices in Massachusetts, as well as throughout New England. That reduction in prices translates into a reduction in the total cost of wholesale electric energy to Massachusetts energy users, relative to the Reference Case, of $237 million. Figure 14 shows the total gross energy market cost savings due to the market price impacts shown in Figure 13.

Figure 14. Total gross energy market cost savings attributable to the price differential between the CHP Case and the Reference Case by month for Massachusetts



This $237 million of reduction in wholesale electric energy cost is attributable to the energy generated by the CHP resources that reduces purchases from the wholesale market. The energy market cost savings attributable to the market price impacts of demand resources is calculated by multiplying the net load (gross load minus demand resource savings) in each scenario by the average price differential in each scenario. For the CHP scenario, that impact is $53 of savings to Massachusetts energy users in 2020 for every MWh of CHP generation in Massachusetts.[48] This is $237 million divided by annual CHP generation of 4.445 million MWh in the CHP Case).

Most of that $237 million in market price reduction related savings accrues to "non-participants" who do not own DG, and does not include the cost savings that accrue to the owners of the CHP resources as a result of reducing the amount of energy they purchase from the market. When the value of the reduced demand is accounted for, the total gross energy cost savings is $694 million.

[48] The additional savings for the rest of the load in New England is not included in these Massachusetts impacts.

Impacts of Energy Efficiency

Figure 15 shows the average hourly wholesale electric price differential between the EE Case and the Reference Case by month and peak period. The impact of the efficiency savings averaged over the entire year is -$1.21/MWh, a price reduction of 1.6% from the Reference case.

Figure 15. Average hourly wholesale electric price differential by month and peak period for Massachusetts in the EE Case relative to the Reference Case

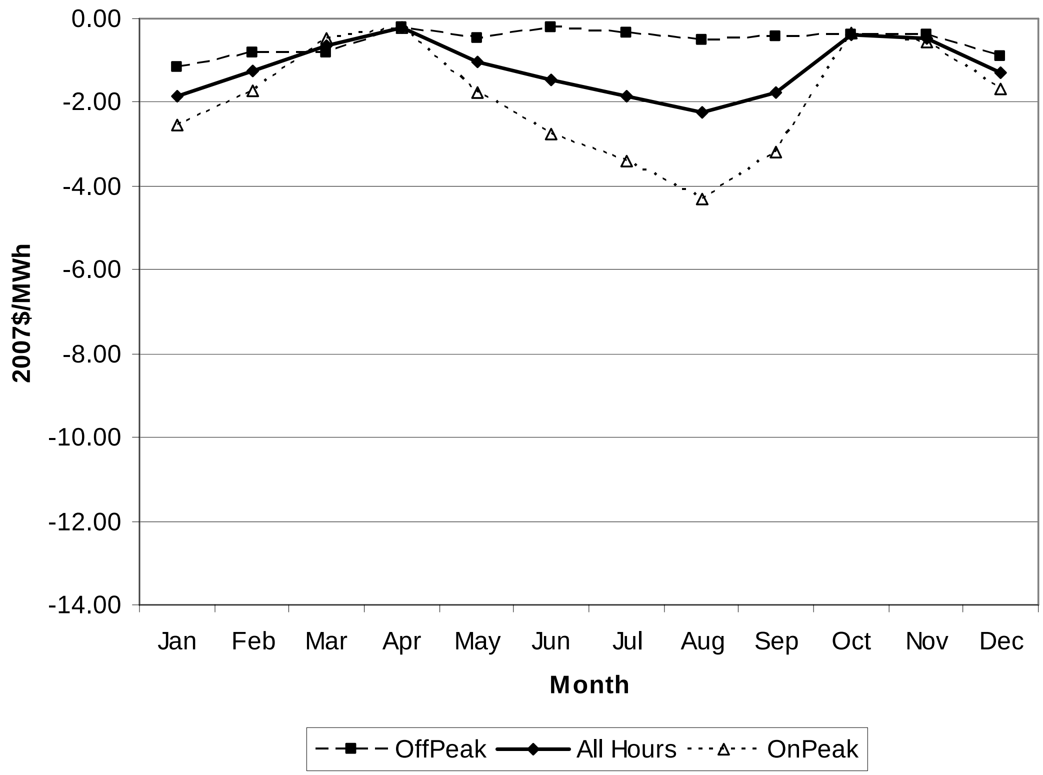
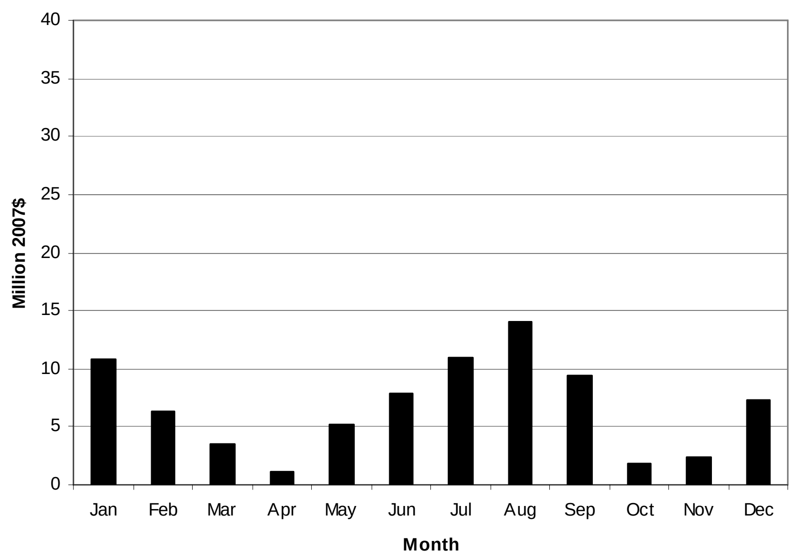


Figure 16 shows the total energy market cost savings due to the market price impacts shown in Figure 15. The annual sum of the cost savings shown in Figure 16 is $81 million. With annual energy efficiency savings in 2020 of 3,568,000 MWh, this equates to a price effect of $23 per MWh of energy efficiency savings. The price impacts attributable to energy efficiency are less than the price impacts attributable to CHP due to the lower load factor assumed in this study for the energy efficiency profile. The energy efficiency profile is assumed to have a 50% load factor[49] while the aggregate CHP profile (including generation from both NPR-CHP and PR-CHP) has a load factor of 68%. The

[49] We assume efficiency savings have the same hourly shape as total load. This is conservative as it does not assume that more emphasis will be placed on reducing electricity use in high price hours than in low price hours..

total annual gross wholesale energy cost savings including the savings attributable directly to reduced demand is $402 million.

Figure 13. Total energy market cost savings attributable to the price differential between the EE Case and the Reference Case by month for Massachusetts



Impacts of the Combined Case: CHP + EE

Figure 17 shows the average hourly wholesale electric price differential between the CHP+EE Case and the Reference Case by month and peak period. When averaged over the entire year the impact of the efficiency is -$3.80/MWh, a price reduction of 5.1% from the Reference case. .

Figure 17. Average hourly wholesale electric price differential by month and peak period for Massachusetts in the CHP+EE Case relative to the Reference Case

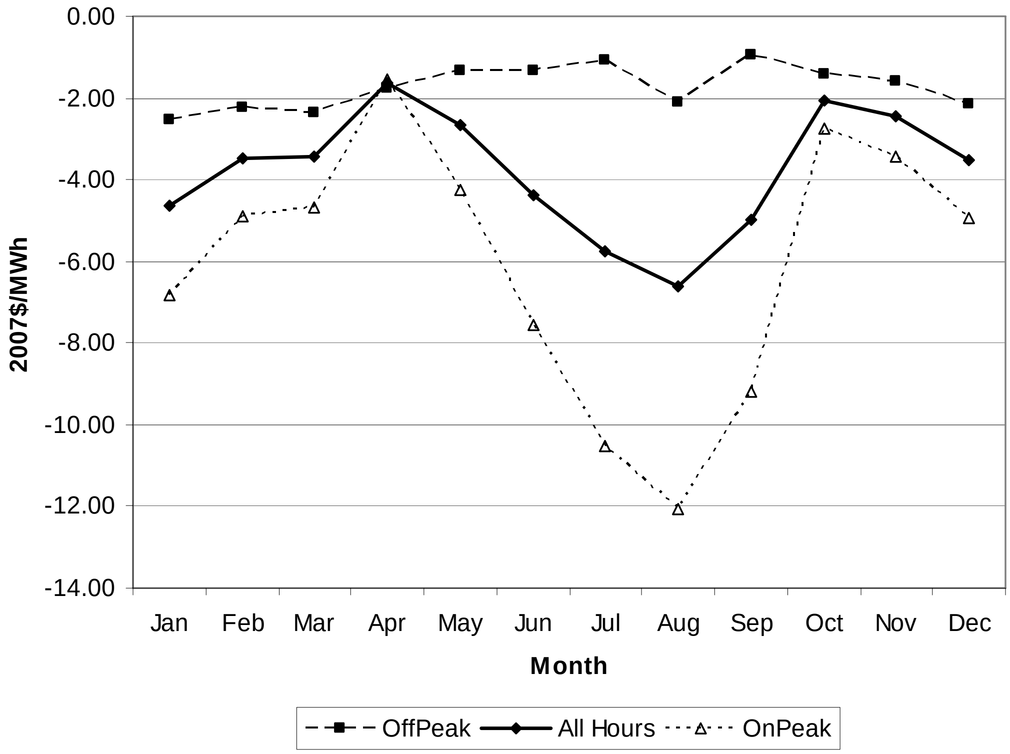
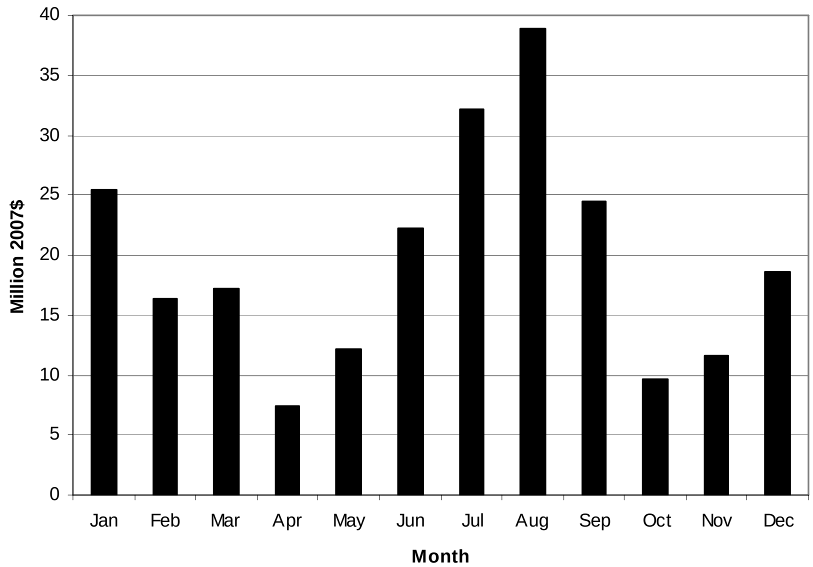


Figure 18 shows the total gross energy market cost savings due to the market price impacts shown in Figure 17. The annual sum of the cost savings shown in Figure 18 is $236 million. With a combined energy savings due to CHP and energy efficiency of 8,026,000 MWh, the price effect is a savings of $29/MWh. The total annual gross wholesale energy cost savings including the savings attributable directly to reduced demand is $986 million.

Figure 18. Total energy market cost savings attributable to the price differential between the CHP+EE Case and the Reference Case by month for Massachusetts



Incremental Impacts of CHP+EE Case Compared to EE Case

Figures 19 and 20 show the incremental market price impacts of CHP after accounting for the price impacts of energy efficiency savings by showing the average market price differential between the CHP+EE Case and the EE Case. Figure 19 shows the average hourly wholesale electric price differential between the CHP+EE Case and the EE Case by month and peak period. When averaged over the entire year the impact of the combined case is -$2.60/MWh, a price reduction of 3.5% from the efficiency case.

Figure 19. Average hourly wholesale electric price differential by month and peak period for Massachusetts in the CHP+EE Case relative to the EE Case

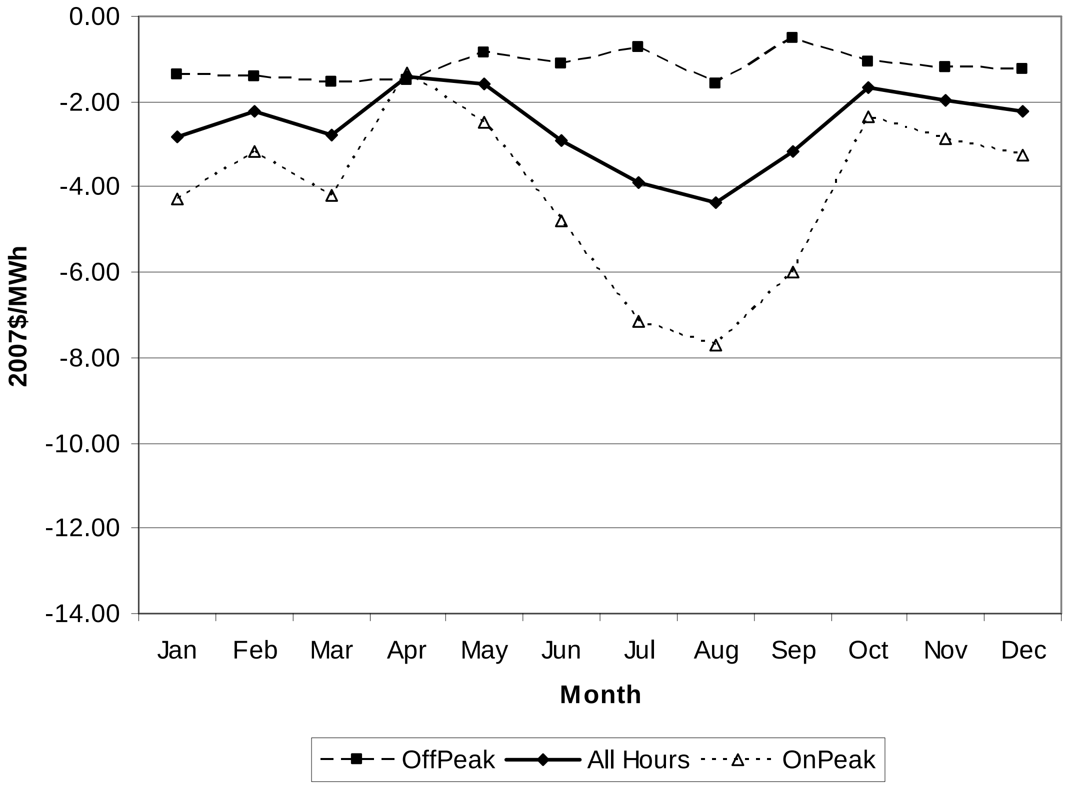
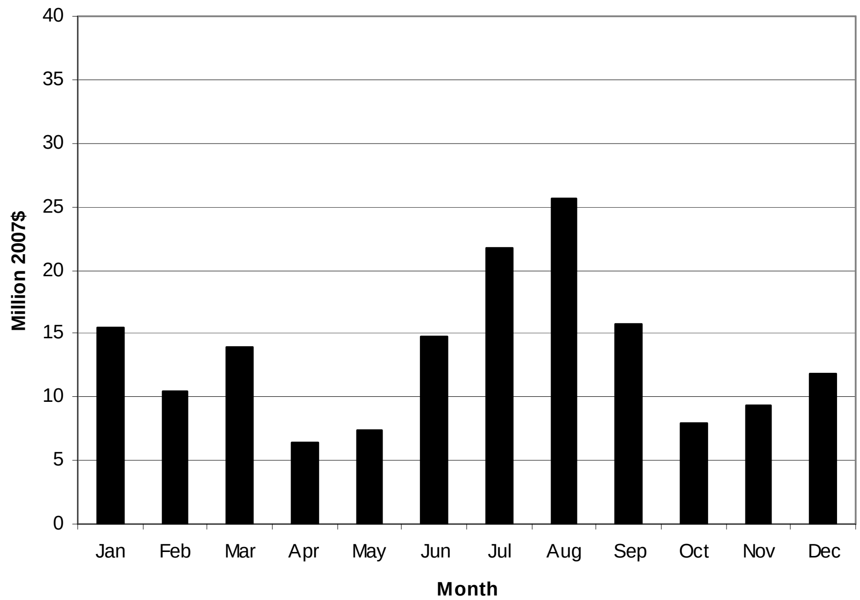


Figure 20 shows the incremental gross energy market cost savings attributable to CHP. The annual sum of the cost savings shown in Figure 18 is $156 million which equates to $35 per MWh of CHP generation[50].

The total annual incremental gross energy market cost savings attributable to CHP, including the savings attributable directly to reduced demand, is $583 million.

[50] Note that the incremental GHP generation in the CHP +EE case is 4,458 GWh, slightly more than the 4,446 GWH under the CHP case.

Figure 20. Total energy market cost savings attributable to the price differential between the CHP+EE Case and the EE Case by month for Massachusetts



Summary of Cases with CHP and Energy Efficiency

Table 13 shows the average monthly price reductions by period attributable to CHP and energy efficiency and the statistical significance of these reductions. The bottom row shows the annual price impacts as percentages of the average market price.

Table 13. Average hourly wholesale electricity price differential ($/MWH) by month and period for Massachusetts relative to the Reference Case. Values that are statistically significant within a 95% confidence interval are shown in bold

	CHP Case			EE Case			CHP+EE Case		
Month	All Hours	Off-Peak	On-Peak	All Hours	Off-Peak	On-Peak	All Hours	Off-Peak	On-Peak
Jan	**-4.38**	**-2.79**	**-5.99**	**-1.84**	**-1.14**	**-2.55**	**-4.66**	**-2.52**	**-6.84**
Feb	**-3.18**	**-2.08**	**-4.46**	**-1.24**	**-0.84**	**-1.72**	**-3.46**	**-2.25**	**-4.89**
Mar	**-3.13**	**-1.89**	**-4.51**	**-0.66**	**-0.82**	-0.47	**-3.45**	**-2.35**	**-4.67**
Apr	**-1.66**	**-1.60**	**-1.73**	-0.22	-0.23	-0.21	**-1.65**	**-1.74**	**-1.55**
May	**-2.53**	**-1.36**	**-3.94**	**-1.04**	**-0.46**	**-1.75**	**-2.64**	**-1.34**	**-4.23**
Jun	**-3.90**	**-1.18**	**-6.73**	**-1.45**	-0.19	**-2.77**	**-4.37**	**-1.31**	**-7.55**
Jul	**-5.08**	**-1.27**	**-8.97**	**-1.85**	-0.35	**-3.38**	**-5.75**	**-1.07**	**-10.54**
Aug	**-6.08**	**-2.19**	**-10.82**	**-2.24**	-0.52	**-4.33**	**-6.59**	**-2.10**	**-12.05**
Sep	**-4.76**	**-1.20**	**-8.48**	**-1.78**	-0.41	**-3.21**	**-4.97**	**-0.93**	**-9.19**
Oct	**-2.41**	**-1.49**	**-3.44**	-0.37	-0.37	-0.37	**-2.05**	**-1.44**	**-2.73**
Nov	**-2.30**	**-1.39**	**-3.35**	**-0.46**	-0.37	-0.57	**-2.44**	**-1.58**	**-3.44**
Dec	**-3.89**	**-2.55**	**-5.25**	**-1.29**	**-0.90**	**-1.68**	**-3.52**	**-2.13**	**-4.94**
Annual	**-3.62**	**-1.75**	**-5.66**	**-1.21**	**-0.55**	**-1.92**	**-3.80**	**-1.73**	**-6.07**
Annual (%)	**-4.9%**	**-2.9%**	**-6.4%**	**-1.6%**	**-0.9%**	**-2.2%**	**-5.1%**	**-2.8%**	**-6.9%**

The annual impacts on wholesale prices in 2020 are presented in Figure 21(a) for each of the cases discussed above, and are summarized for each resource in Figure 21(b).

Figure 21(a). Average annual 2020 wholesale market price reductions for Massachusetts for each case [51]

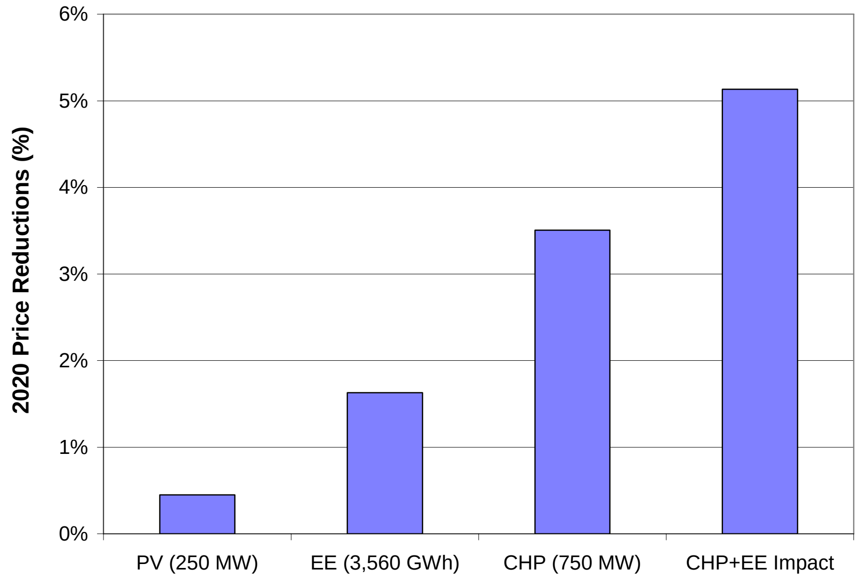
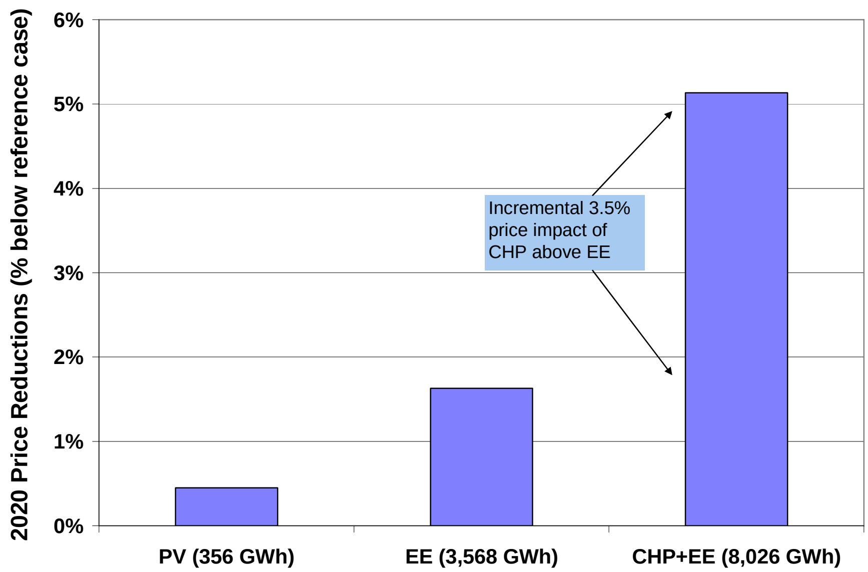


Figure 21(b). Average annual 2020 wholesale market price reductions for Massachusetts for each demand resource[52]



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51 The impact of 750 MW of CHP is the price reduction from the scenario with energy efficiency included. The price reductions for the other bars in this chart are from the Reference Case.

52 The impact of 750 MW of CHP is the price reduction from the scenario with energy efficiency included. The price reductions for the other bars in this chart are from the Reference Case.

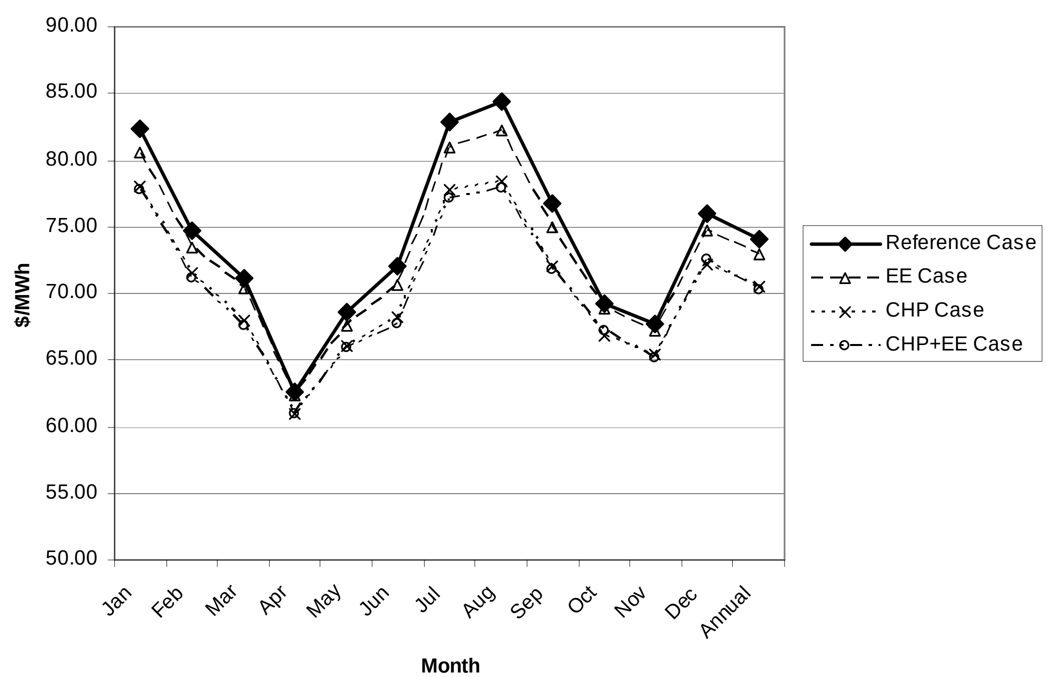
The price reductions due to CHP and energy efficiency are fairly consistent across all of the modeling zones that serve Massachusetts load. This is consistent with how these resources were distributed to these zones which was based on zonal loads. Table 14 shows these reductions.

Table 14. Zonal average annual wholesale electric energy price reductions as a percentage of the average annual price in the Reference Case

Zone	CHP Case	EE Case	CHP+EE Case
Boston	-5.0%	-1.8%	-5.4%
CMA/NEMA	-4.7%	-1.5%	-4.3%
RI	-4.9%	-1.4%	-5.3%
SEMA	-4.9%	-1.7%	-5.3%
WMA	-4.5%	-1.4%	-4.8%

Figure 22 shows the average prices by month in the CHP and EE Cases compared to the Reference Case average monthly prices. This chart shows how the price reductions are greatest in the highest price months. This is very evident in July and August. During these periods, the region of the supply curve at which the demand curve intersects is steeper then at lower load points. Therefore, load reductions at these higher load levels result in greater price reductions than at lower load levels where the supply curve is flatter.

Figure 22. Comparison of average hourly electric wholesale energy prices for Massachusetts



Gross Environmental Impacts

Tables 15(a) to 15(c) show the reductions in regional emissions from the wholesale electric system in each case relative to the Reference Case. Table 15(d) summarizes these reductions for CO2, and presents them in terms of CO2 reductions per MWh of DG generation or efficiency savings. The net impacts from CHP are presented in the next section, taking into account the emissions from the CHP systems themselves at customer sites.

As expected, DG and energy efficiency resources result in measurable reductions in emissions in New England. These resources also contribute to emissions reductions in areas outside of New England.[53]

Table 15(a). Emissions reductions in the CHP Case relative to the Reference Case

Control Area	CO2	NOX	SO2	Mercury
	(000 Short Tons)	(000 Short Tons)	(000 Short Tons)	(lbs)
ISO-NE	1,481	0.59	2.29	1.5
Maritimes	152	0.20	0.39	0.8
NYISO	600	0.33	0.95	4.5
Quebec	31	0.01	0.00	0.0
Total	2,265	1.13	3.63	6.8

Control Area	CO2	NOX	SO2	Mercury
ISO-NE	2.3%	1.7%	4.0%	1.3%
Maritimes	0.7%	0.6%	0.3%	0.2%
NYISO	1.1%	1.2%	2.0%	1.4%
Quebec	1.5%	1.0%	0.0%	n/a
Total	1.6%	1.2%	1.4%	0.7%

[53] The values in the rows represent percentage comparisons within each control area. The change in total CO2 emissions across all the control areas is in the "Grand Total" row, and is presented as a percentage of the total electric sector emissions for all these control areas. The relationship between the control areas is further illustrated in Table 14(d) below.

Table 15(b). Emissions reductions in the EE Case relative to the Reference Case

Control Area	CO2	NOX	SO2	Mercury
	(000 Short Tons)	(000 Short Tons)	(000 Short Tons)	(lbs)
ISO-NE	1,478	0.45	2.23	0.2
Maritimes	42	0.05	0.14	0.4
NYISO	38	0.01	0.03	0.7
Quebec	11	0.01	0.00	0.0
Total	1,568	0.52	2.40	1.3

Control Area	CO2	NOX	SO2	Mercury
ISO-NE	2.3%	1.3%	3.9%	0.2%
Maritimes	0.2%	0.1%	0.1%	0.1%
NYISO	0.1%	0.0%	0.1%	0.2%
Quebec	0.5%	1.0%	0.0%	n/a
Total	1.1%	0.5%	0.9%	0.1%

Table 15(c). Emissions reductions in the CHP+EE Case relative to the Reference Case

Control Area	CO2	NOX	SO2	Mercury
	(000 Short Tons)	(000 Short Tons)	(000 Short Tons)	(lbs)
ISO-NE	2,923	0.99	4.06	1.1
Maritimes	139	0.18	0.42	0.9
NYISO	419	0.23	0.75	4.0
Quebec	32	0.02	0.00	0.0
Total	3,512	1.42	5.23	6.0

Control Area	CO2	NOX	SO2	Mercury
ISO-NE	4.5%	2.8%	7.1%	1.0%
Maritimes	0.6%	0.5%	0.3%	0.2%
NYISO	0.8%	0.9%	1.6%	1.2%
Quebec	1.6%	2.0%	0.0%	n/a
Total	2.4%	1.5%	2.1%	0.6%

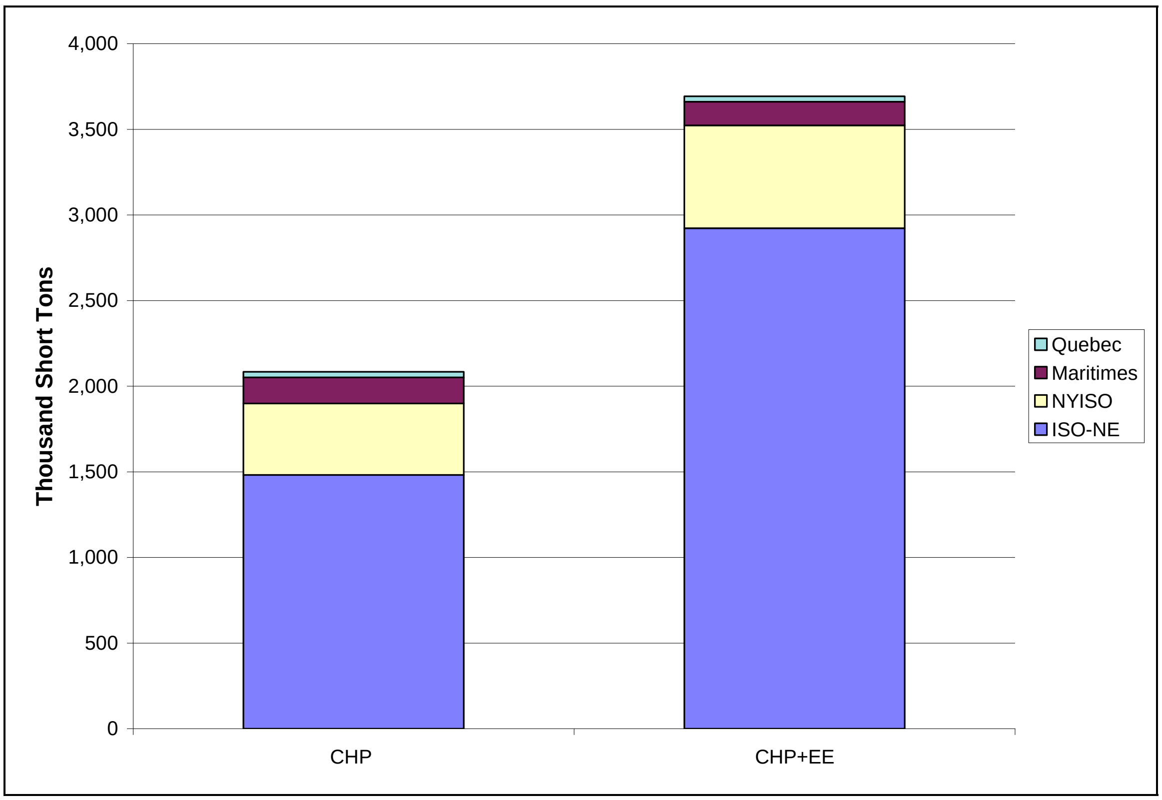
Table 15(d) shows that DG and EE will reduce gross CO2 emissions from the electric generating sector by between 872 lb/MWh of CHP generation and 994 lb/MWh of PV generation in the year 2020. These impacts reflect reductions in all four control areas. These marginal CO2 reduction rates reflect the mix of generating units expected to be operating in 2020 and the hourly generation or savings profiles of these resources.

Table 15(d). Marginal CO2 emission reduction rates by case

Case	CO2 Reductions (000 Short Tons)	Resource Quantity (GWh)	Reductions (lb/MWh)
PV	177	356	994
EE	1,568	3,568	879
EE+CHP	3,512	8,026	875
CHP, Incremental	1,944	4,458	872

Figure 23 compares the "gross" quantity of CO_2 reduced in each case relative to the Reference Case. The gross quantity represents the reduction in CO_2 emissions from generation sold into the wholesale electric energy market in 2020. The net quantity, which we report below, is the gross quantity minus the emissions associated with the gas used in the incremental CHP capacity.

Figure 23. Gross reductions in electric system CO_2 emissions attributable to CHP and energy efficiency



Net CO2 Impacts

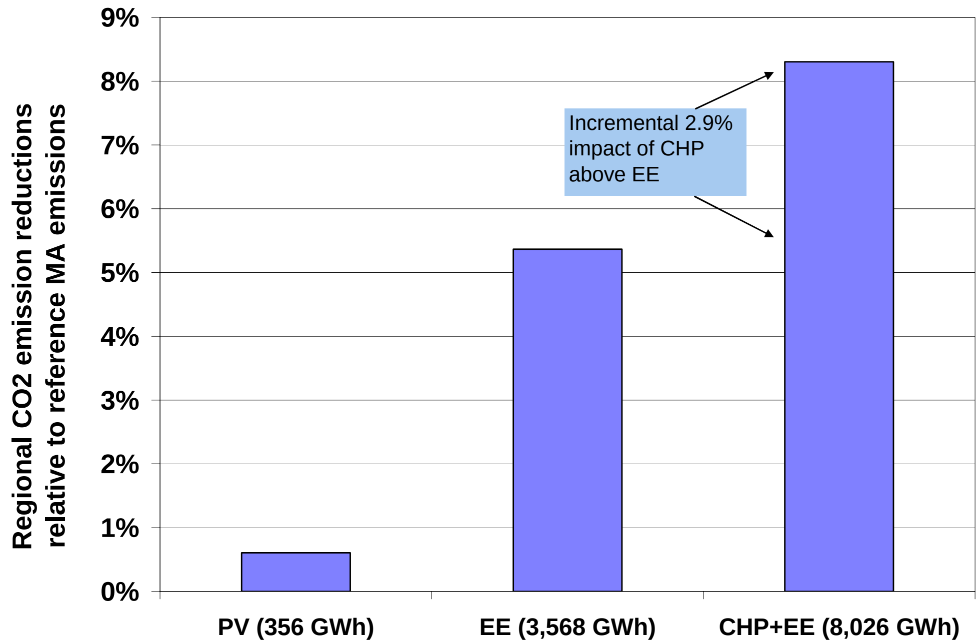
The emission impacts from CHP are a combination of the emission reductions from displaced grid generation, which were addressed in the previous section, plus the emission reductions from displaced onsite thermal generation, minus the emissions from the onsite CHP system. The on-site emissions from CHP and the CO2 reductions from reducing the use of onsite boilers can vary significantly depending on CHP technology, the boiler fuel displaced, and other factors. Nevertheless, based on the estimates described below, the following Table 16 combines these on-site impacts for CO2 emissions with the total of grid impacts from Table 15 above, to show the net percentage reductions.

Table 16. Comparison of reductions in net CO2 by control area (short tons)

	EE vs. Reference	CHP+EE vs. Reference	CHP+EE vs. EE
Reduction by Control Area in 2020 (Tons 000)			
ISO-NE	1,478	2,923	1,445
Maritimes	42	139	97
NYISO	38	419	381
Quebec	11	32	21
Grid Total	1,568	3,512	1,944
+ Thermal Dispaced On-site		1,743	1,743
- CHP Emissions On-Site		2,849	2,849
Net Reductions	**1,568**	**2,406**	**838**
Net reduction relative to MA	**5.4%**	**8.3%**	**2.9%**

In the CHP+EE case, the net CO2 reductions in 2020 are approximately 2.4 million short tons/year. This is equivalent to approximately 8% of the Massachusetts CO2 emissions under the Reference Case. The incremental impact of CHP in the CHP+EE case, i.e. the additional impact over the EE case, is a further reduction of 837,000 short tons. That incremental impact is equivalent to 2.9% of the Massachusetts CO2 emissions under the Reference Case. The net reductions under the PV, EE and CHP+EE cases are illustrated in Figure 24.

Figure 24. Reductions in regional CO_2 emissions in 2020 under PV, EE and CHP+EE cases relative to Reference Case Massachusetts CO2 emissions



The net reductions from CHP in Figure 24 take into account the on-site CHP emissions based on emission and performance assumptions from the KEMA report. The following Table 17 presents CO2 emission characteristics of typical CHP technologies.

Table 17. CO2 emission characteristics of typical CHP technologies[54]

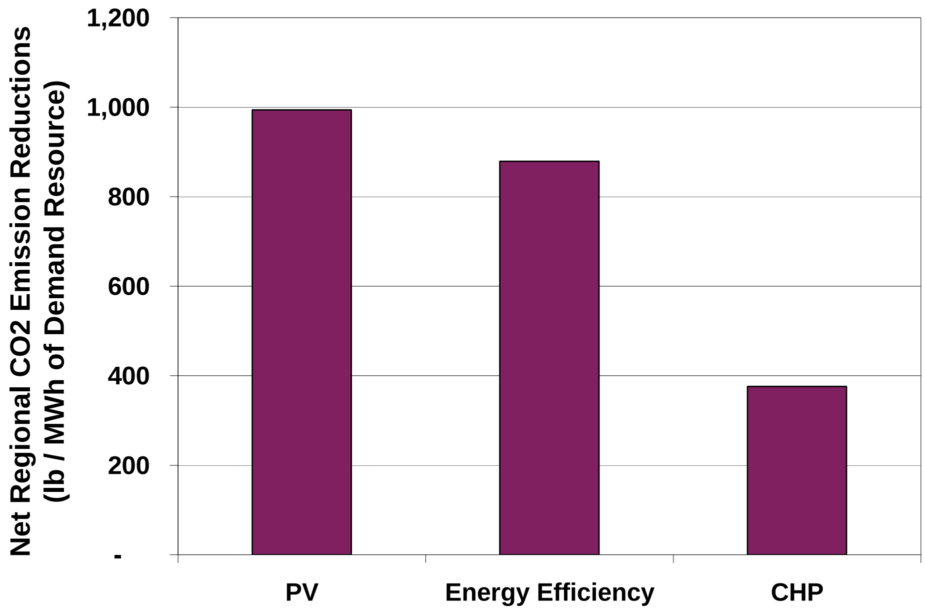
	Recip Engines	Gas Turbines	
Typical CHP Projects			
Electrical Efficiency	33%	30%	
Power/Heat Ratio	73%	76%	
Net Heat Rate	4,506	5,773	
Total CHP Efficiency	78%	69%	
CHP Capacity (kW)	300	5000	
Capacity Factor	64%	71%	
Generation of CHP Project (MWh/year)	1,686	30,948	
CO2 (short tons/year)			
Emissions from CHP	1,026	20,405	
Displaced onsite thermal generation: gas	579	10,039	
Displaced onsite thermal generation: oil	791	13,729	
Displaced onsite thermal: mix	685	11,884	
Displaced grid generation	734	13,462	
Net CO2 decrease (short tons/year)	393	4,941	
Projections for 2020			**Weighted Average per projected total annual generation**
CO2 Emission rates, lb/MWh:			
Emissions from CHP	1,217	1,319	**1,282**
Displaced onsite thermal generation	812	768	**784**
Net on-site increase	404	551	**497**

The top half of the table shows the emissions (in short tons) for typical CHP installations based on reciprocating engines and gas turbines, along with the underlying assumptions. The bottom half of the table presents the weighted average rates of CO2 emissions or emission reductions, in short tones per MWh of CHP generation, based on the potential mix of engine- and turbine-based CHP generation expected in 2020. The net on-site increase of 497 lb/MWh presented in Table 17 would differ based on the mix of CHP technologies installed through 2020, the performance and efficiency and emission characteristics of those CHP projects and the displaced fuels and technologies that would have been used for onsite generation of thermal energy.

[54] Source: KEMA, op. cit.

Figure 25 compares these greenhouse gas reductions between different demand resources based on the quantity of energy generated or saved by each resource. For PV and EE, these figures are the same as the marginal emission reduction rates in Table 15(d) above. For CHP, the value of 375 lb/MWh is based on 872 lb/MWh regional reduction rate from Table 15 minus the 497 lb/MWh of net on-site emissions from CHP listed in Table 17.

Figure 25. Reductions in net regional CO_2 emissions in 2020 from PV, EE and CHP resources (lb/MWh) [55]



[55] The emission reductions due to CHP in this chart are based on the incremental reductions from the CHP+EE Case relative to the EE Case.

6. Comparison with Energy Market Price Impacts Identified in Other Studies

The analyses presented in Chapters 4 and 5 demonstrate that increasing the quantities of energy acquired or saved via additional DG and EE will, by reducing the quantity of energy purchased from the wholesale market, lead to lower prices for electric energy in that market. As noted earlier, this effect is sometimes referred to as a Demand-Reduction-Induced Price Effect. The wholesale electric energy price impacts identified This Chapter summarizes those results and comments on similar results identified in other studies.

A. Price Impacts from DG and EE Identified in this Study

The wholesale electric energy price impacts identified in our study are presented in Figure 26.

Figure 26. Reduction in average annual wholesale electric energy price for Massachusetts purchases in 2020 under PV, EE and CHP+EE cases[56]

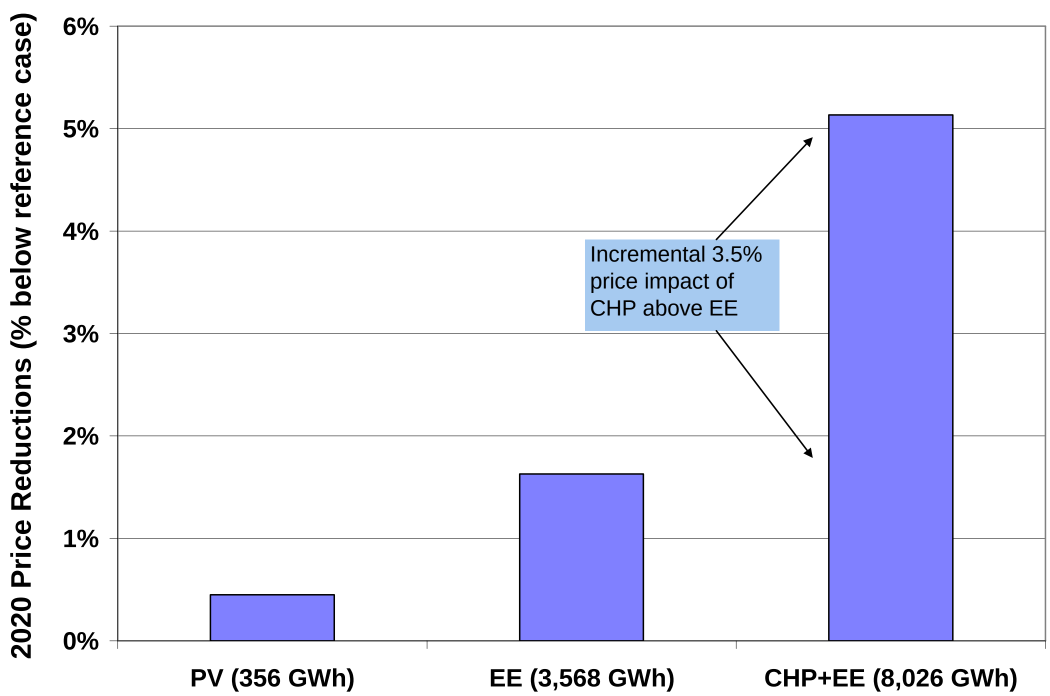


Figure 27 presents the price effect expressed as dollars per MWh of wholesale market cost savings to Massachusetts customers per MWh of DG and/or EE responsible for those benefits.

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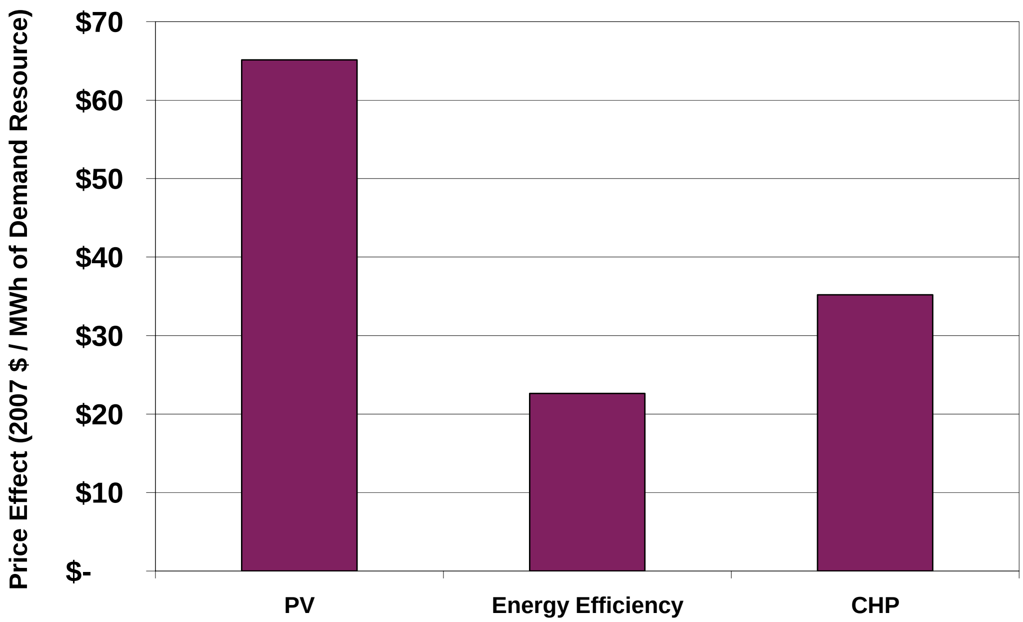
56 The impact of 750 MW of CHP is the price reduction from the scenario with energy efficiency included. The price reductions for the other bars in this chart are from the Reference Case.

Figure 27. Price Effect: impact on annual costs of Massachusetts purchases of wholesale electric energy in 2020 from PV, EE and CHP resources (2007 dollars)[57]



For comparison purposes we examined comparable price effects identified, either implicitly or explicitly, in two other recent studies of wholesale electric energy prices in New England. The studies were the Scenario Analyses prepared by ISO-NE in 2007 and *Avoided Energy Supply Costs in New England 2007 Final Report* ("AESC 2007"), prepared by a team from Synapse Energy Economics, Resource Insight and the Swanson Energy Group.

B. ISO New England Scenario Analysis

In 2007 ISO NE evaluated the operation of the wholesale electric power system through 2020 under several different future scenarios. They used a similar analytical method, i.e., simulating the operation of the market for various cases under alternative scenarios. Their Scenario Analysis documents are located on ISO New England's website[58].

In that exercise ISO-NE examined a number of resource strategies under each scenario including case 1, a "queue" or business-as - usual approach, and case 52, an "all efficiency" approach. One can derive an implicit energy price effect by comparing results of the all-efficiency case to the results of the queue case, as indicated in Table 18.

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57 The price impact from CHP in this chart is based on the incremental price impact of the CHP+EE Case relative to the EE Case.

58 http://wwww.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/index.html

Table 18. Impact on annual costs of purchases of wholesale electric energy in 2020 under EE and CHP+EE cases and under ISO "All Efficiency" case

		DG and EE Scenario Analysis		ISO NE Scenario Analysis	
Scope		MA Load only		New England Market	
	Units	EE	CHP + EE	Queue (case 1)	All Efficiency (case 52)
Total Load Served	GWh			173,773	173,773
Load Served by EE or DG	GWh			0	36001
Net Load Served from Wholesale Market	GWh			173,773	137,772
Reduction in Load met from Market	%	**5%**	**13%**		**21%**
Market Price	$/MWh			$ 69.04	$ 62.80
					$ 6.24
Reduction in Market Price		**2%**	**5%**		**9%**
Reduction in Costs of Purchases from Wholesale Market (Change in Price * Net Load served from Wholesale Market)	$ million				$ 860.01
Price Effect: Reduction in Wholesale Market Cost per MWh of EE or DG	$/MWh	**$ 22.64**	**$ 29.40**		**$ 23.9**

The implicit energy DRIPE derived from the ISO NE analyses is approximately $24 per MWh of EE. This is the same order of magnitude as the energy price effect for the EE and CHP+EE cases in this study. However, it is interesting to note that the energy price effect from the ISO NE analysis is not much larger than the results in this study despite its assumption of a much higher percentage reduction (21%) in purchases from the wholesale market.

C. 2007Avoided Cost Study (AESC)

The AESC 2007 Report[59] includes an estimate of the price effect in the energy market.[60] That estimate is a function of three separate factors:

- The effect of load reduction on market energy prices, if all energy traded in the spot market and the supply system did not change as a result of DRIPE effects. This impact was not estimated by simulating the operation of the wholesale market under two separate cases, e.g. a Reference case and then an energy efficiency case. Instead, it was estimated by determining the historical variation in locational energy market prices as a function of variation in zonal and regional loads, both from the day-ahead market, and then applying the resulting coefficients to projected prices and loads.
- The pace at which supply will adapt to energy-efficiency load reductions; and
- The percentage of power supply to retail customers that is subject to market prices in the current year and each future year.[61]

The final price effect was the product of the direct effect from the first factor, times the percent of the effect not yet eliminated by supply adaptation from the second factor, times the percentage of power supply that is subject to market prices from the third factor. The resulting estimates of the benefit per MWh of one year's energy savings were presented in Table 6-11 of that report for each of the first four years after the energy efficiency installations, e.g. 2008 through 20011 for measures installed in 2007). They are reproduced in Table 19.

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59 Synapse Energy Economics, *Avoided Energy Supply Costs in New England*, prepared for the Avoided Energy Supply Component Study Group, 2007. Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2007-08.AESC.Avoided-Energy-Supply-Costs-2007.07-019.pdf

60 The AESC report also analyzed the potential price effect in the capacity market.

61 This adjustment was not incorporated into the present study because the DG capacity would be introduced gradually through 2020 and would therefore tend to affect contract prices as well as spot prices over time.

Table 19. Impact on annual costs of purchases of wholesale electric energy in New England from AESC 2007 (2007$ per MWh Saved)

		Zone							
Year	Season	CT	ME	NH	RI	VT	NEMA	SEMA	WCMA
				On-Peak					
1	Summer	33.2	23.7	28.3	24.1	24.5	28.9	31.0	26.1
1	Winter	16.5	15.1	15.2	14.5	14.6	15.2	18.1	15.4
2	Summer	100.2	69.3	75.5	70.3	71.2	84.0	90.1	76.0
2	Winter	48.7	44.1	42.3	42.6	42.1	43.9	52.3	44.5
3	Summer	97.1	65.1	69.4	66.0	66.8	78.2	83.6	71.1
3	Winter	46.3	40.8	39.2	40.3	39.4	40.9	48.4	41.5
4	Summer	59.1	39.5	41.9	40.1	40.6	47.6	50.9	43.2
4	Winter	28.1	24.7	23.7	24.5	23.9	24.9	29.5	25.2
				Off-Peak					
1	Summer	16.4	10.1	14.2	10.4	9.8	12.6	12.6	9.7
1	Winter	13.3	12.4	14.4	11.8	11.5	13.1	14.1	11.7
2	Summer	50.5	29.8	34.0	31.4	28.6	36.7	36.7	28.5
2	Winter	39.4	36.5	37.1	34.7	33.5	38.0	41.0	34.1
3	Summer	49.5	27.6	30.1	29.9	26.6	33.8	33.8	26.5
3	Winter	37.3	33.5	33.5	32.6	31.1	35.2	37.8	31.7
4	Summer	30.1	16.7	18.1	18.1	16.2	20.6	20.6	16.1
4	Winter	22.7	20.3	20.2	19.8	18.9	21.4	23.0	19.3

The results in Table 19 present the impacts on wholesale energy prices estimated to flow through to purchasers. These results present the impacts for purchases from the wholesale market throughout all of New England, rather than just for purchasers to meet load within Massachusetts. In contrast, Table 20 presents the full impact of price reduction related impacts in each zone from demand reductions in that zone. These results are drawn from the statistical analysis of historical period (April 2006 through March 2007) price impacts used to develop estimates of energy DRIPE in AESC 2007.

Table 20. Impact on average cost of purchases of wholesale electric energy in Massachusetts based on historical market data

In-Zone only Energy Cost Effect per MWh of in zone energy reduction ($/MWh)								
Average Apr 06 - Mar 07	CT	ME	NH	RI	VT	NEMA	SEMA	WCMA
	57.1	9.8	18.4	9.1	5.6	30.6	32.3	20.4

In contrast to the AESC 2007 analysis, the cases modeled for this present study represent snapshots of 2020. These snapshots show that DG resources can have a significant impact on electric energy market prices and on the total gross annual electric energy market costs. This study did not explicitly analyze the question of how long these impacts would persist. However, in the CHP and EE scenarios, the capacity mix was adjusted to maintain a regional reserve margin that is consistent with the reserve margin in the Reference Case, as described in Section 5 above. This reduction in new capacity additions incorporated into the 2020 DG modeling scenarios a response of the market over time to the downward pressure that incremental CHP and energy efficiency additions would have on the demand for capacity.

The types of units assumed to be displaced in this manner were not based on a separate analysis of the relative economics of new generic capacity additions and, thus, may not represent the optimal supply mix with lower demand and lower market prices. With lower energy prices, marginal generators that rely more on energy revenues relative to other revenue sources (capacity payments, ancillary services payments, etc.) would be more likely to be out of the money in a scenario with reduced energy prices than a unit that does not rely as much on energy revenues. It is possible that with lower energy market prices, the market may respond by meeting remaining new capacity needs primarily with CT capacity as opposed to CC capacity, resulting in upward pressure on market prices.[62] However, despite any changes in the regional capacity mix that may arise with significant amounts of CHP and energy efficiency investment, the shape of the regional supply curve will likely not change enough to substantially dampen the energy price reductions attributable to demand resources.

Other factors may also apply downward pressure on market prices. First, the reductions in purchases from the wholesale market under the DG and EE cases modeled in this study would tend to flatten the shape of the remaining load met by purchases from the wholesale market. In other words the peak loads would be lower relative to the annual load. This means fewer hours during which purchases are being made at the high price end of the wholesale market supply curve. That could lead to retirement of older, relatively inefficient generators. Those retired units would be replaced, as needed, by new, more efficient generators with lower operating costs. Such changes to the load shape would produce persistent price savings regardless of any likely supply-side changes. Also, to the extent that lower electric system demand reduces demand for natural gas, it would lead to reductions in natural gas prices.

Thus, the duration and magnitude of reductions in wholesale market prices are a function of a variety of factors which interact in complex ways. In the short term a reduction in demand results in a reduction in wholesale price following basic economic laws of supply and demand. In the longer term the supply side will adjust to lower prices, for example closure of inefficient existing plants or postponement of new projects. That could cause prices to rise and offset the price reduction effect somewhat. However it is unlikely that existing capacity with low- to moderate- generation costs will be retired. Thus any price rebound will primarily occur in a relatively few hours with peak prices. This indicates that price reductions from reducing the level and shape of the load met from the wholesale market should be long-term and unlikely to be materially offset by any price rebound due to supply-side reactions.

[62] This study did not estimate the capacity price DRIPE from DG, which would offset such a shift to CTs.