The Pennsylvania State University

Department of Energy and Mineral Engineering

EQUILIBRIUM MODELING OF COMBINED HEAT AND POWER DEPLOYMENT IN PHILADELPHIA

A Thesis in

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by

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ABSTRACT

Combined heat and power (CHP) generates electricity and heat from the same fuel source and can provide these services at higher equivalent conversion efficiency relative to grid-purchased electricity and stand-alone steam production. Previous work has focused on the economic factors and optimal operation strategy that influence the decision to install a single CHP unit. Our approach is to assess the economic potential for CHP in electricity-market equilibrium framework, accounting for the impact that CHP adoption will have on energy prices. A statistical model of electricity supply and pricing is utilized to estimate zonal supply curves for transmission constrained electricity markets. The above model of electricity prices is coupled with simulated usage of CHP in different types of buildings, using the Philadelphia area as a case study. Incremental installations of CHP reduce the electricity demand from the grid, thus reducing wholesale electricity prices. The results suggest that electricity price reduction (and savings) is sensitive to natural gas prices and the operational strategy of CHP. In particular, the impacts of CHP adoption will have larger impacts on the electricity prices under high gas-price scenarios. This is due primarily to the reductions in peak-time electricity demand. Also, operating CHP units in FEL mode has a larger impact on the electricity price duration curve (through larger reductions in demand for grid-provided electricity) than does operating CHP units in FTL mode. The net present value from CHP is modeled as a function of wholesale electricity prices, and thus decreases with each additional unit of CHP installed. Marginal savings and marginal NPV curves were estimated for three gas price scenarios and two CHP operation strategies (i.e., CHP-FTL and CHP-FEL). The marginal savings and marginal NPV decrease as the number of CHP units increase for all three-gas price scenarios and two CHP operation strategies. At low natural gas prices, the economic potential for CHP-FTL is about one-tenth of technical potential. If all CHP units are operated according to FEL, the economic potential is larger (around three to four times as large as under FTL operations) but still substantially smaller than the technical potential in the lower gas price scenarios. This study suggests that the priority rankings for CHP deployment are important considering a large-scale adoption of CHP in a region. The results suggests that higher natural gas prices and hence higher electricity prices, is favorable for CHP adoption. Under a range of operational assumptions and fuel prices, substantial CHP deployment could be achieved without reducing returns to the point where existing and incremental CHP installations would become uneconomic.

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Chapter 1

Introduction

1.1 Background

Reliable and affordable energy sources are essential for the economic stability of a country. Energy insecurity and increasing oil prices has raised concerns about the future in both developed and developing countries. The potential impact of greenhouse gases (GHGs) emissions is far reaching making it decisive to switch to low GHG emitting technologies. Regardless of the efforts taken by policymakers, energy related carbon emissions are in an upward trend is a huge concern. According to International Energy Agency, the CO_2 emissions are projected to increase by 55 percent by 2030[1]. The global energy demand is increasing in parallel making it vital to change the current scenario. Enhancing energy security, reducing dependence on fossil fuels and reducing GHGs significantly enough to slow down global warming involves many different approaches. The current scenario demands a combination of promoting both energy efficiency measures and alternative energy sources for a sustainable energy policy. This includes energy efficiency practices in consumer and supply side along with renewable energy sources, nuclear energy, carbon capture and other clean energy technologies. According to the U.S Department of Energy, buildings sector contributes to 70 percent of the total electricity and 50 percent of the total gas consumed, which is the maximum among all sectors[2]. Energy efficiency in buildings is a key focus area to decrease energy consumption and positively affect the environment by reducing the carbon footprint with short payback period and

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[1] World Energy Outlook Reference Scenario, International Energy Agency 2007

[2] Building Technologies Program Factsheet, Prepared by National Renewable Energy Laboratory for U.S Department of Energy. http://apps1.eere.energy.gov/buildings/publications/pdfs/corporate/btp_fs.pdf

higher economic returns. It is important that energy efficiency measures be supported by favorable policies and incentives along with other alternate sources of energy. A great bulk of the co-produced heat during electricity generation goes as waste, which results in decreasing the efficiency. Figure 1.1 shows the energy flows in the global electricity system. It can be seen that approximately two-thirds of the fuel used for electricity generation is wasted as heat in addition to the transmission and distribution losses. The average efficiency of electricity generation in the U.S has been around 35 percent for the last few decades[3]. The conversion loss in the form of wasted heat in United States in the power generation sector is greater than the total energy use of Japan[4]. Combined heat and power captures and reuses this waste heat.

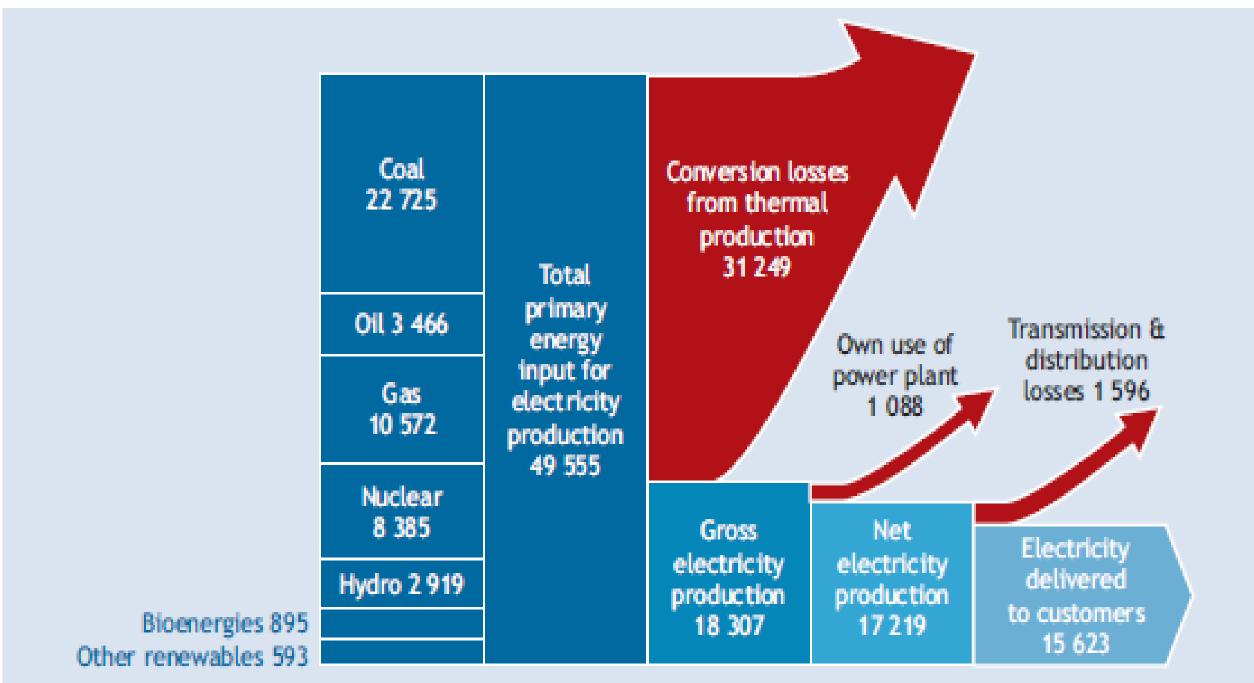

Figure 1.1 Energy flows in global electricity system. Source: IEA 2008

[3]U.S Environmental Protection Agency Combined Heat and Power Partnership
http://www.epa.gov/chp/basic/efficiency.html

[4] See page 5 of "Combined Heat and Power, Effective energy solutions for a sustainable future" prepared by Oak Ridge National Laboratory

1.2 Combined heat and power

Combined heat and power (CHP) also known as cogeneration, is the onsite production of electricity where the co-produced heat is captured and utilized for space heating, cooling, dehumidification, increasing the overall efficiency of the system. The basic characteristic of a CHP system is that it generates electricity and heat efficiently from the same fuel source, commonly natural gas, compared to the conventional method of providing electricity, through the power grid, and producing onsite heat using a gas fired boiler system. CHP can be employed in a variety of commercial and industrial units that have significant and concurrent electricity and thermal loads profiles. CHP can be linked with existing district heating schemes in municipalities or university campus and this practice is proven viable in countries like Denmark and Finland.

The efficiency gains from CHP compared to the conventional power stations, which generates electricity and rejects the waste heat, is significant. Figure 1 compares the overall process efficiency of a 5 megawatt (MW) natural gas-fired combustion turbine CHP system and conventional heat and power generation. The average overall efficiency of producing power and heat through the traditional system is around 51% whereas efficiency gains from using a CHP unit is around 75. In addition, there are losses associated with the transmission and distribution of electricity, which lowers the overall efficiency of conventional method. CHP system offers an efficient way of power generation as they produce electricity locally and thus minimize the distribution losses. It captures the heat produced, which is used for space or water heating, dehumidification and other specific process applications. Since both electricity and heat is produced from the same fuel source, the energy saving potential of CHP systems are substantial. Another potential benefit is that CHP systems can be operated during periods of peak demand when the electricity prices are high.

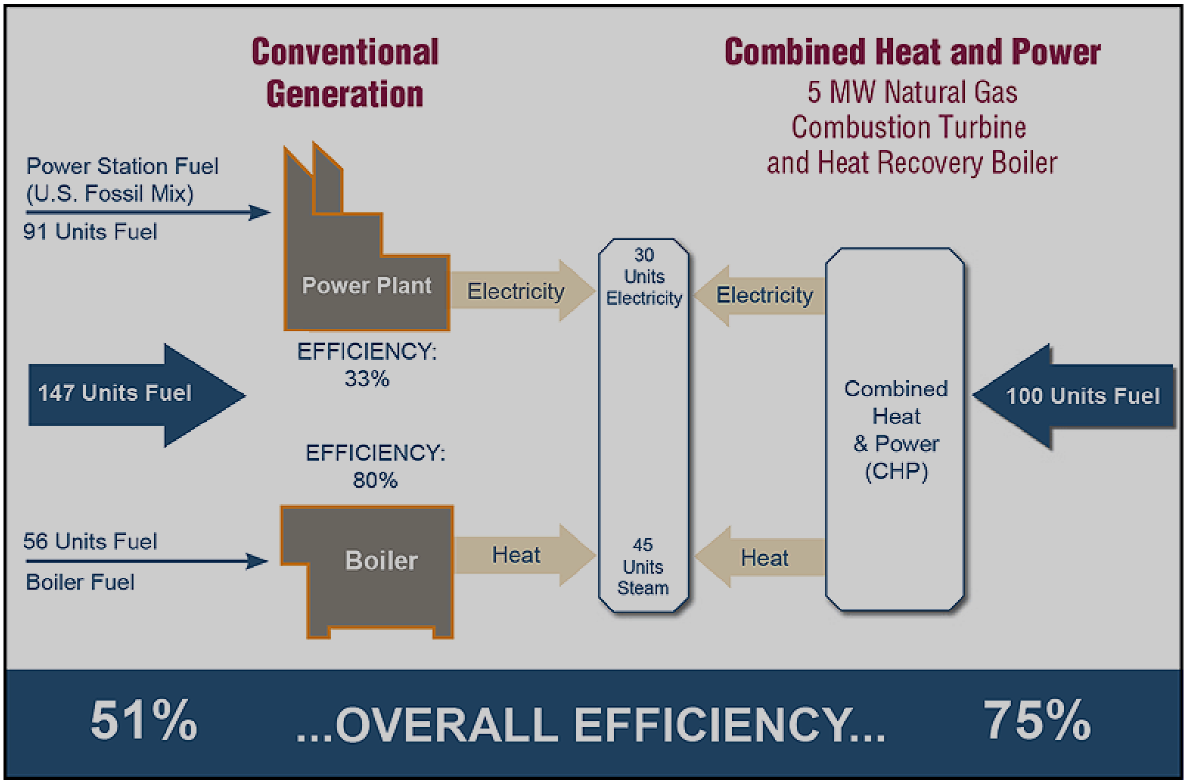

Figure 1.2 – Efficiency gains from CHP[5]

CHP systems also decrease the dependence on power grid and provide reliable and high quality power supply. CHP acts as a backup source of power during periods of continued power outages caused by natural disasters or breakdown in electricity grid. In an article titled "Lessons from Where the Lights Stayed on during Sandy" discussed how people residing in Co-op city, a large housing cooperative benefited from a 40 MW cogeneration plant[6]. The Co-op city is residence to more than 60,000 people with 35 high-rise buildings, 3 shopping centers, a high school and 3 grade schools. The 40 MW cogeneration plant provided power to all the residents during and after the hurricane Sandy when rest of the New York City was facing power outage.

[5] U.S EPA Combined Heat and Power Partnership. See http://www.epa.gov/chp/basic/efficiency.html

[6] http://www.forbes.com/sites/williampentland/2012/10/31/where-the-lights-stayed-on-during-hurricane-sandy/

Electricity generation is the major contributor of GHGs emissions in the U.S. which provides opportunities to reduce emissions in the electricity sector. Combined heat and power systems offer significant environmental benefits when compared to conventionally generated electricity and onsite-generated heat. Lesser fuel is burnt to generate same quantity of power and heat when compared to the conventional generation. Since lesser fuel is burnt greenhouse gas emissions, such as carbon dioxide (CO_2), as well as air pollutants like nitrogen oxides (NOx) and sulfur dioxide (SO_2) is substantially reduced.

Currently there is 82 GW of installed CHP capacity at over 3,700 industrial and commercial facilities across the U.S[7]. Figure 2 shows the split of the existing CHP capacity across various sectors. About 87 percent of the existing CHP capacity is found in industrial settings, in particular energy intensive industries such as chemicals, paper, refining, and metals manufacturing. The share of installed CHP capacity in commercial and institutional applications is about 13 percent. CHP in commercial applications are designed to meet the electricity, heating and cooling demand in hospitals, schools, university campuses, hotels, and office buildings. The existing CHP capacity in the United States corresponds to avoided fuel consumption of about 1.9 quadrillion Btu and 248 million metric tons of carbon dioxide (CO2) emissions annually compared to traditional production of heat and power.

[7] Combined Heat and Power: A clean energy solution.
http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_clean_energy_solution.pdf

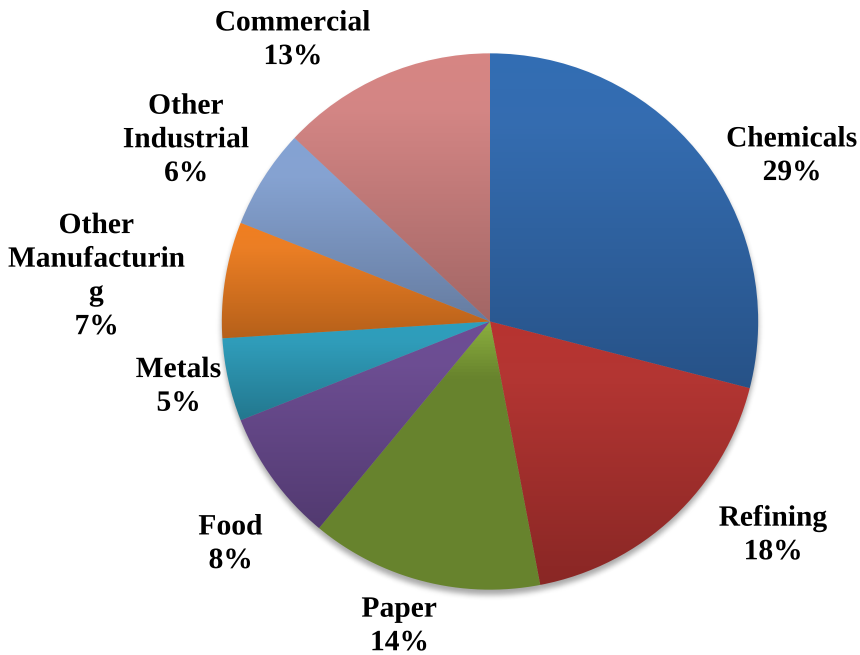

Figure 1.3 - Existing CHP capacity by sectors in U.S[8]

Even though there is a long history of CHP being a part of decentralized power station located at industrial facilities, its adoption increased significantly after 1980 (as seen in figure 3). The main reason was the passing of the Public Utilities Regulatory Policies Act (PURPA) in 1978 prompted by the oil crisis. This act encouraged commercial and industrial facility to generate on-site power by CHP or renewables, in the process improve energy efficiency. The facilities also had access to grid for back up and to sell back excess electricity generated at a reasonable price. Following PURPA, tax incentives were provided for cogeneration equipment resulting in an expansion of CHP capacity in the U.S.

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[8] Combined Heat and Power: A Clean energy solution. http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_clean_energy_solution.pdf

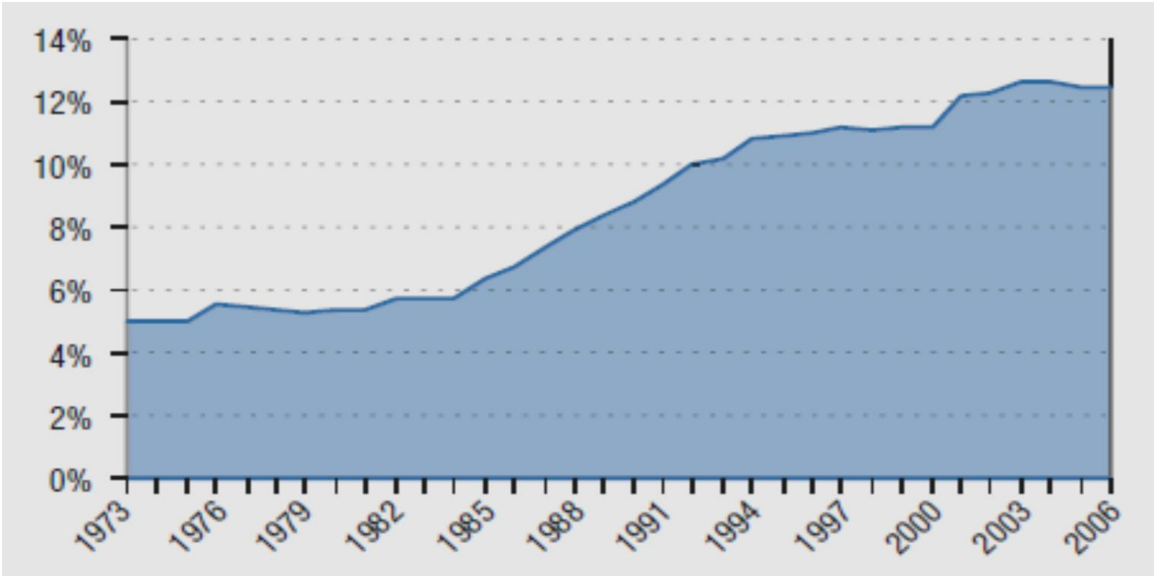

Figure 1.4 - CHP as percentage of U.S annual electricity generation[9]

The current CHP capacity represents about 8 percent of the U.S. generating capacity and a little more than12 percent of total annual electricity generated. However, CHP is still under-utilized and there is lot of technical potential left across the U.S. According to a study by Mckinsey & Company in 2007, under "proper market conditions" CHP can achieve CO_2 emissions at a negative marginal cost in both commercial and industrial applications(Sweetser and Foley 2011; Shipley et al. 2008). The study compared CO_2 abatement costs for various technologies ranging from energy efficiency practices, carbon capture technologies and renewables. CHP was one of the most cost effective, with a negative CO_2 abatement cost among the CO_2 abatement technologies and practices. Unlike solar and wind power generation, CHP is not restricted by geography and time that it is available.

[9] Combined Heat and Power: Effective Energy solutions for a sustainable future, ORNL.

The International Energy Agency has identified CHP as a scheme to reduce GHG emissions and improve energy efficiency. The European Union has come up with a cogeneration directive, which encourages investments in CHP and promotes energy efficiency through CHP. European countries like Denmark, Finland has been a frontrunner in implementing CHP effectively by combining it district heating. A contrasting difference between the U.S. and Denmark is that electricity generation from CHP is mainly controlled by utilities and is linked to the district heating scheme(Unterwurzacher 1992).

About 50% of non-industrial heating demand in Denmark was met through district heating schemes and most of the cities and towns were well connected through this district heating scheme. This provided an ideal setting for the expansion of CHP where the rejected heat from power plants was fed into the existing district heating network. Also, the presence of economic stimulating measures like investment subsidy and other regulation instruments which increased the attractiveness of CHP investment were key to success of CHP in countries like Netherlands and Denmark(Hendriks and Blok 1996).

CHP adoption in some of the European countries has been significantly more compared to the rest of the world. Feed in tariffs and greenhouse gas policy mechanisms have been used in Europe to promote CHP(Shipley et al. 2008). CHP's share of total electricity production in countries like Finland and Denmark are around 38% and 52% respectively. In comparison, the U.S share of electricity produced from CHP is less than 10%. Figure 1.6 shows the share of electricity production from CHP in several countries and the average share of total electricity production from CHP is only 9%(Tanaka 2008).

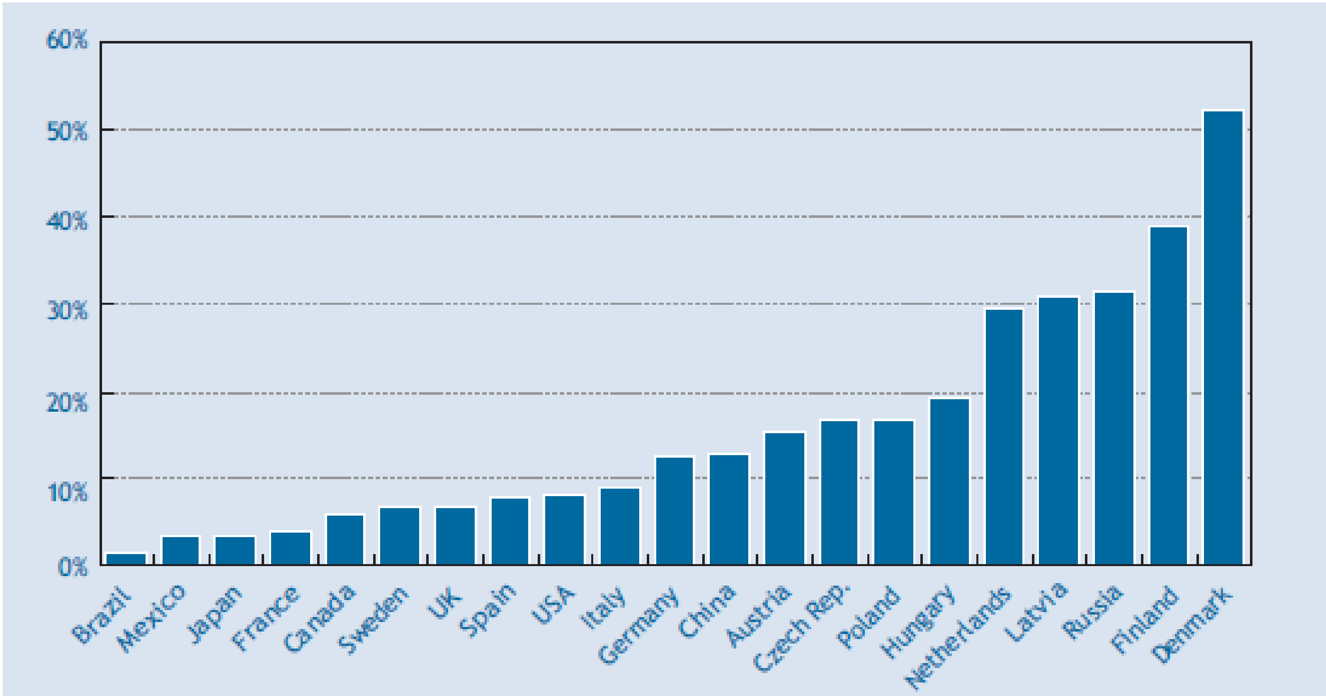

Figure 1.5 - CHP share of total electricity production. Source: International Energy Agency 2008.

1.3 Pennsylvania's current CHP scenario

The first use of CHP in Pennsylvania was in 1929 in a paper mill in Tyrone where coal was burnt produce electricity and the wasted heat was utilized(Sweetser and Foley 2011). Pennsylvania has 125 CHP installed sites with a total capacity of 3,301 MW of which 3,218 MW was installed before 1999[10]. Of the total 63 MW capacity installed in the last decade, only 2.8 MW was natural gas based CHP, the remaining were run mainly on solid waste or biomass (Sweetser and Foley 2011).

[10] ICF International, Combined Heat and Power Installation database. Based on the database, I created a map which contains locations of current CHP installations in Pennsylvania. The map can be accessed at, http://batchgeo.com/map/79e686d7d36a658890c5d69290d10756

Natural gas is primarily used for CHP systems accounting for more than 70 percent of the current CHP capacity in the whole of U.S. The cost saving potential of CHP largely depends on natural gas prices and volatile natural gas prices increases the potential risk of CHP investment and has been a barrier for CHP adoption. The recent development of Marcellus Shale gas reserves, which is the second largest natural gas reserve in the world, will have a major impact on the economy of the Mid-Atlantic region. This also means that there will be a rapid increase in the natural gas production in the region. The increased production will tend to lower the market price for natural gas in the region and make CHP investments more cost-effective.

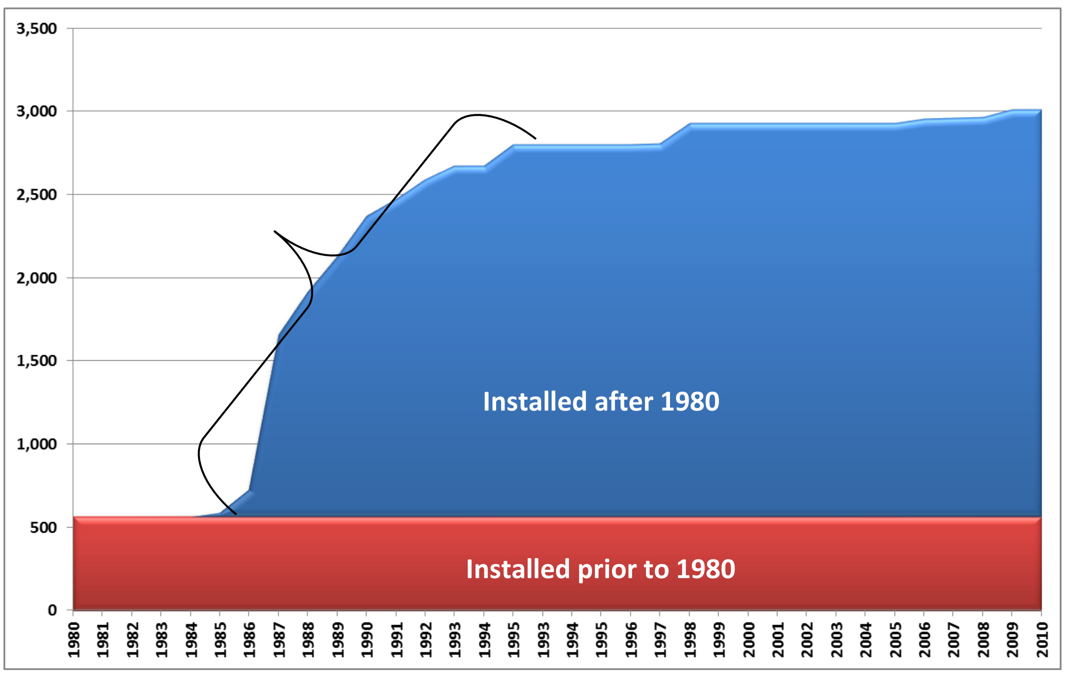

Figure 1.6 - Pennsylvania's existing CHP capacity. Source: Sweetser and Foley 2011

Currently, coal generators meet a major share of Pennsylvania's electricity demand. A majority of these coal generators is less efficient and with new emissions standards set by the EPA, significant number of generators will retire from service[11]. The recent surge in the natural gas production will attract investments in new natural gas fired central power stations, which are more efficient, and has lesser emissions. Another potential use of the natural gas is in the deployment of natural gas based CHP, which does not require a large capital investment but can reduce emissions. However, as mentioned before, CHP adoption has been slow over the last decade due to lack of market drivers favoring CHP. To change this scenario there is a need for favorable policies supporting the penetration of CHP in the market. An additional 1,836 MW of new natural gas CHP capacity corresponds to 40 trillion Btu/year of primary energy savings and CO_2 emissions reductions of 34.3 million short tons (Sweetser and Foley 2011). Pennsylvania has significant CHP technical potential remaining (figure 1.7) and it is important that the policy makers realize energy savings and emission reduction potential of CHP and make policies, which encourage CHP adoption.

[11] According to Sweetser and Foley 2011, "EPA emission standards for electric utility steam generating units are projected to take 11 GWs of old coal generators off PJM and add to the capital cost of new pulverized coal power plants".

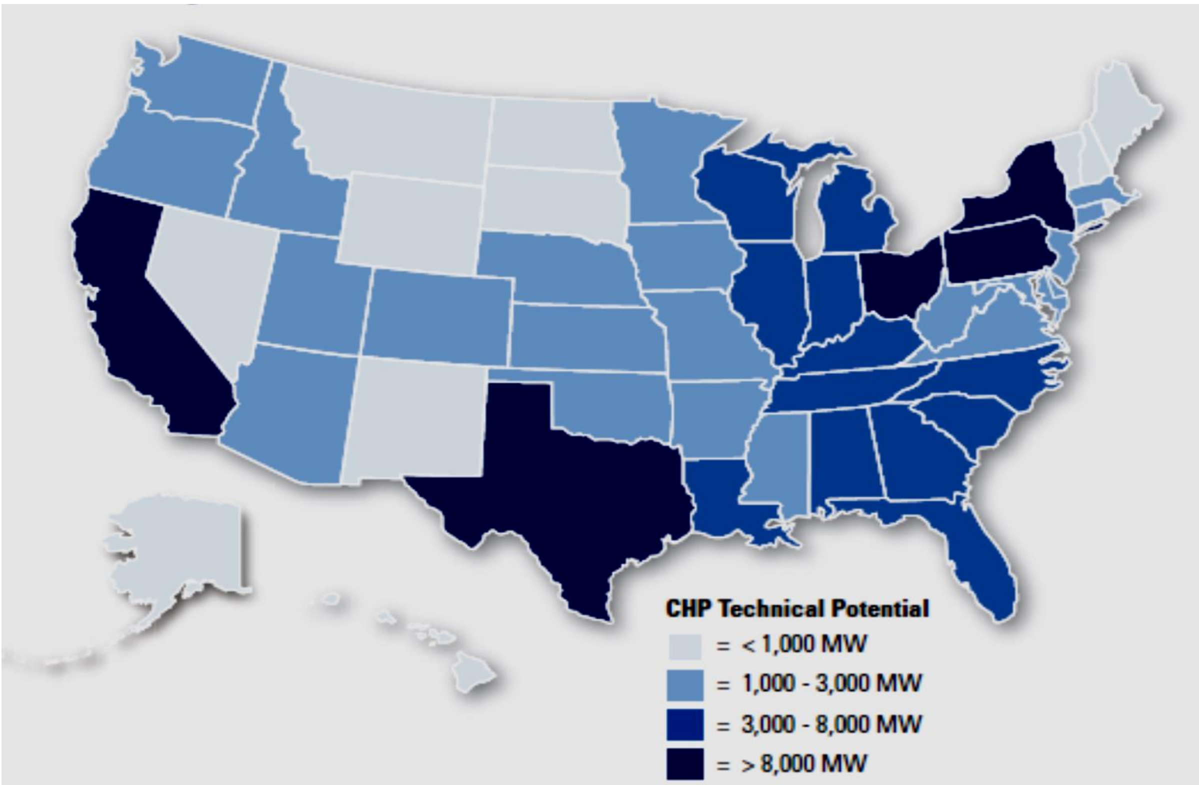

Figure 1.7 - Remaining CHP technical potential in U.S. Source: Oak Ridge National Laboratory

1.4 Objectives of this study

Combined heat and power has various benefits in the form of monetary savings, increased efficiency and lower CO_2 emissions. CHP systems are efficient and proven near-term energy solution that is under-utilized for various reasons. Shipley et al [2008] discusses some of the hurdles for CHP adoption, which includes electricity rate structure, interconnection issues with grid, tax treatment and technical barriers related to capital costs, fuel costs, flexibility of CHP Even with various potential benefits, CHP adoption has been slow across the world; especially in the U.S. It is important to understand the market factors, which affect the economics of CHP and its adoption.

The existing literature has studies, which look at the impact of a single CHP unit, and its related benefits. This study looks at the impacts of a large-scale adoption of CHP in a region and its impact on zonal electricity prices. With recent development of Marcellus shale, the role of CHP as a potential consumer of natural gas is vital for the Mid-Atlantic region. A large-scale deployment of CHP will increase the natural gas utilization, which will support the drilling activities of Marcellus shale by keeping the natural gas price from dipping.

The objective of my thesis is to estimate the equilibrium level of CHP market deployment in commercial buildings in Philadelphia, which comes under the PECO zone. The basic idea is to estimate the point at which a marginal CHP investment will have a net present value of zero. A part of this study involves estimating zonal supply curves for PECO and measuring the impact of new gas fired generators on zonal electricity prices. We use this working model of PECO's zonal supply curves to evaluate impact of large-scale deployment of CHP in Philadelphia.

The rest of the thesis is organized as follows: chapter 2 reviews the relevant literature. Chapter 3 discusses the two models used in this study; the first model is used to estimate the supply curves for PECO zone with transmissions constraints and the second involves modeling the equilibrium level of CHP deployment in Philadelphia. Data on new gas fired additions in PJM electricity market and the building stock under study in Philadelphia is discussed in Chapter 4. This chapter also includes information on the hourly load profiles generated for each type of building using the BCHP screening tool. Chapter 5 discusses the results of the analysis and chapter 6 examines the conclusions from this study and scope for future work.

Chapter 2

Literature Review

Combined heat and power is not a new technology and has been in practice for a long time. The first commercial power plant in the U.S by Thomas Edison in 1882 was the first cogeneration plant as it produced electricity and the rejected heat was used for space heating in nearby buildings. Even though CHP's benefits have been realized, its adoption has been slow and has not reached its maximum potential. In a study conducted by the International Energy Agency, it was found that CHP adoption was effective and full potential was realized in countries, which identified CHP as a key strategy to overcome energy security and global warming issues.

The U.S Department of Energy has a set an aggressive target of 20 percent CHP generation capacity by 2030. In a report by the Oak Ridge National Laboratory for the U.S Department of Energy, it was estimated that if the target was achieved it will save 5.3 quadrillion Btu of fuel annually and an 800 million metric tons reduction of CO_2 emissions per year along with the 1 million technical jobs across the U.S(Shipley et al. 2008).

CHP is a near term energy solution which is less resource intensive compared to other green technologies. Compared with other green technologies, the payback period for CHP is much shorter; wind 20-25 years, solar 15-25 years, CHP 2-8 years(Zilnois 2010). A comparison between 10 MW capacity of CHP, wind and natural gas combined cycle revealed that CHP had the lowest of cost of power with 7.6 cents per kWh without including the transmission and distribution costs which is avoided in the case of CHP (U.S EPA Combined heat and power partnership). The U.S DOE has supported several cases of CHP deployment in industrial and commercial settings. For example, a case study of a CHP system installed in NewYork-Presbyterian Hospital reported to have savings around $5 million per year, and will reduce CO_2 emissions by 67,000 tons annually.

Several studies have been conducted the application of CHP to different types of commercial buildings. A study conducted to study the emission reduction potential of CHP systems in seven types of commercial buildings showed that hospitals had the highest reduction of CO_2, NO_x, and CH_4 emissions(Pedro J. Mago and Smith 2012). In addition, it was found that schools and small offices showed an increase in the primary energy consumption. It should be noted that CHP deployment is not beneficial for all types of buildings. The application of CHP systems to various commercial buildings requires understanding of the difference in energy consumption patterns, thermal and electric ratios. In a report assessing the cogeneration market potential prepared by Lawrence Berkley National Laboratory, commercial buildings types were ranked based on the size, hours of operation, system configuration and concurrence in thermal and electric loads(Huang et al. 1991).

A shortcoming with deploying CHP in commercial buildings is the utilization of the rejected heat during summer. However, the heat from CHP can be used to run an absorptive chiller to provide air conditioning. This is called tri-generation or combined cooling, heat and power (hereafter CCHP)(Siler-Evans, Morgan, and Azevedo 2012). This provides the flexibility of using the heat for space heating in the winter and cooling in the summer. The CCHP systems allow the heat to be used continuously throughout the year unlike the CHP systems where the heat goes as waste during the summer. In a study comparing the use of CHP and CCHP units to a supermarket, it was found that the CCHP system had better primary energy saving potential but had a higher payback period(Maidment, Zhao, and Riffat 2001). The higher payback period was attributed to the capital costs associated with the absorptive chiller. In addition, it was found better payback period was achieved as the size of the chiller unit increased and as the demand for the chiller unit increases. In a case study of small-scale generation in a hospital, it was found that the absorptive chillers were cost-effective addition to the CHP system(Siler-Evans, Morgan, and Azevedo 2012). An economic feasibility study of applying CCHP systems to a hospital showed that the project and low payback period and high net present value(Ziher and Poredos 2006). CHP/CCHP systems differ in their performance with respect to reduction in primary energy consumption or operation costs or emissions based on the strategy to operate following electrical load or thermal load. If a CHP/CCHP system is operated to follow the electrical load, the generator will run to meet the electricity demand of the facility and the co-produced heat may or may not be sufficient to meet the heating load. If co-produced heat is not sufficient, additional heat has to be provided the boiler system. If a CHP/CCP system is operated to follow the heating load, the generator will be operated so that the recovered heat will meet the heating load of the facility. The electricity produced may not be sufficient to meet the facility's electricity load in which case additional electricity will be bought from the grid(Cardona and Piacentino 2004; P.J. Mago and Chamra 2009). In a study evaluating the performance of CHP /CCHP systems, it was found that the CHP/CCP following thermal load always reduced the primary energy consumption and CO_2 emission while reducing the operation costs. Also, it was found that CHP systems following electric load increases the primary energy consumption (P. J. Mago, Fumo, and Chamra 2009).

Despite the potential benefits, CHP plays a minor role in the U.S. for various reasons. Unlike Europe, regulated electricity rate structure and tariffs pose a hurdle for CHP adoption in the U.S. Interconnection issues with the grid are also a major issue slowing CHP adoption(Shipley et al. 2008). CHP units have been proven efficient with respect to fuel utilization and lesser GHGs emissions, but have struggled to be economically viable. The desire to make CHP systems more economically attractive to investors arises from the fact that they are cost effective and produce fewer emissions per unit of fuel consumption in comparison to conventional power generation. Even though there are regulatory and utility barriers, from an investor's point of view, adopting CHP is a business decision and the economic viability is a crucial factor. Volatile natural gas prices and high capital costs contribute to under-utilization of CHP. Even though CHP typically reduce emissions compared to the conventional method, emission standards that regulate emissions of air pollutants apply for CHP systems as well. Siler-Evans et al [2012] assessed the effectiveness of various mechanisms (demand response, capacity markets, regulation markets, accelerated depreciation and CO_2 pricing) for improving the economics of co-generation. They also found that a two-part feed-in tariff eliminates energy price risks arising from the volatility in fuel (natural gas) and electricity prices, which increase the risk of CHP investments.

Based on the above literature, this study attempts to investigate the potential impacts of a large-scale adoption of CHP. More specifically, this study involves assessing the equilibrium level of CHP deployment in Philadelphia and the impact of a large-scale adoption of CHP on the zonal electricity prices. Previous work has focused on the economic factors and optimal operation strategy, which affects the decision to install a single CHP unit and some of the studies asses the technical potential of CHP. This study is different from the existing literature as it tries to assess the market potential for CHP in Philadelphia, accounting for the impact that CHP adoption will have on energy prices.

Chapter 3

Background on supply curve modeling

In modern restructured electricity markets, such as the PJM market in the United States, market prices change frequently and are influenced primarily by the level of electricity demand. Prices are set by the supply offer of the generating unit that clears the market – i.e., the last unit dispatched to equate total system supply and demand. Shifts in demand will affect the set of generating units dispatched, hence the clearing price in the electricity market. Our approach models the impact of a large-scale CHP adoption on electricity demand in Philadelphia, and the wholesale price of electricity along with the utilization of different fuels to serve aggregate demand for grid-provided power. The impacts on prices for capacity or ancillary services is not considered in this paper, but the costs of these services would be expected to rise and fall along with actual or projected electricity demand.

Modeling electricity prices and fuels utilization in a transmission-constrained electricity markets is complex. Actual supply curves based on cost data from the generation owners or transmission system operators are not public information. Much of the existing literature estimates short run supply curves using data from the Emissions and Generation Resource Integrated Database (eGRID 2007) published by the U.S. Environmental Protection Agency (Newcomer and Apt 2009; Newcomer et al. 2008). Figure 3.1 shows the distribution of fuels used for electricity generation in PJM and figure 3.2 is the estimated short run supply curve for PJM electricity market using the above methodology.

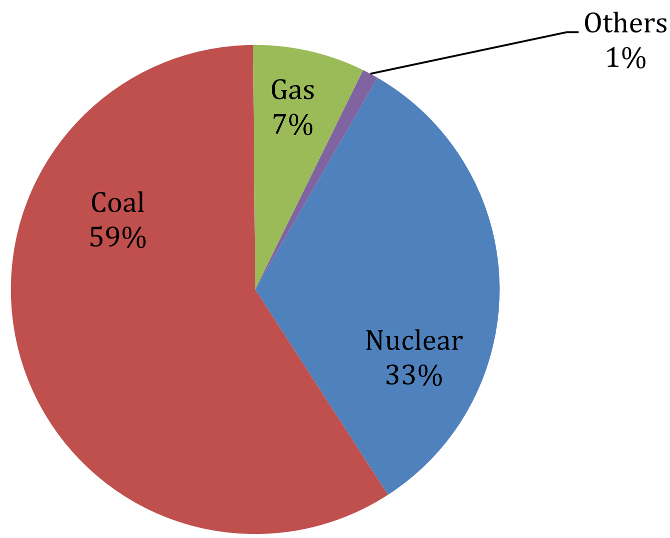

Figure 3.1 Electricity generation in PJM Interconnection

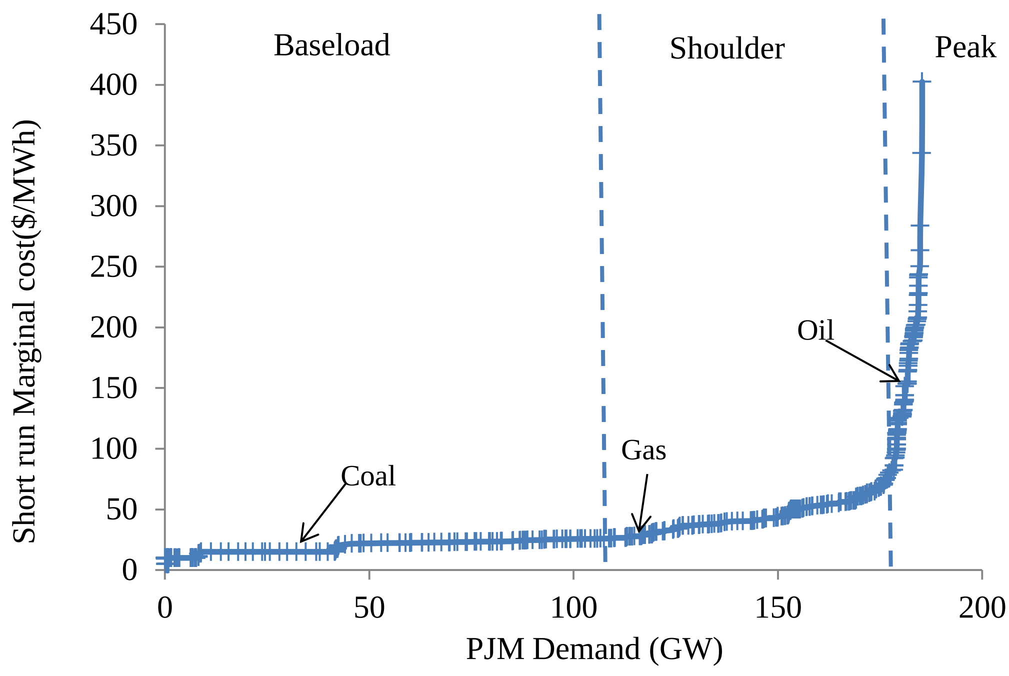

Figure 3.2 - Short run supply curve for PJM electricity market. Each marker represents a generator

These supply curves built in previous work typically model coal generators as being dispatched before natural gas generators in PJM electricity market. This scenario, however, is changing as the recent discovery of Marcellus shale gas reserves has led to a decrease in gas prices in the Mid-Atlantic region. The share of natural gas for power generation has been growing and the share of coal has been declining. Also, coal fired power plants are increasingly facing regulatory hurdles and increased costs related to air emissions of various pollutants (Newcomer and Apt 2009). A second drawback with this approach is that it ignores transmission constraints on the electricity transmission network. Transmission constraints can induce a difference in marginal fuel and prices at two different locations within the same interconnected power system (Sahraei-Ardakani et al 2012). For example, in a location with high demand, oil will be the marginal fuel and therefore higher electricity prices as compared to a location with relatively lower demand where coal or gas will be on the margin and lower electricity prices.

To address this issue, a recent work (Sahraei-Ardakani et al 2012) that estimates statistical models of electricity supply and pricing in transmission constrained electricity markets is used. These estimated supply curves incorporate the transmission constraints in an electricity network unlike the short run marginal cost curves (Figure 3.2) that are estimated using individual plant level data. The approach taken by Sahraei-Ardakani, et al., is to construct an econometric model that estimates prices on a sub-system or "zonal" basis, using publicly-available data on fuel prices and electricity loads. The fuel on the margin in a zone (i.e., the fuel whose price best explains variations in electricity price over a relevant range of demands) is a function of the zonal demand, total system demand and the relative fuel prices. Supply curves for each type of fuel (coal, gas and oil) are determined and each segment represents the influence of the fuel on the electricity price.

In this model, electricity prices are a function of a "membership function" which indicates the influence of fuel on the zonal price and the partial supply curve of the zonal marginal fuel.

$$P_{ik} = \sum_{j=1}^{J} M_{ji}\left(q_{ik}, q_{Tk}, \varphi_{ji}, P_{ik}^{F}\right) SF_{ji}\left(q_{ik}, q_{Tk}, \omega_{ji}, P_{jik}^{F}\right) + e_{ik} \qquad (1)$$

The subscript *i* represents the zone *i, j* indicates the fuel *j*, and *k* is the number of the observation. M_{ji} is the "membership function" identifies the effect of fuel *j* on the zone *I* and *SFij* is the partial supply function regarding fuel *j* at zone *i*. *pik* is the zonal electricity price, is the vector of zonal fuel prices and *qik* is the zonal load. φ_{ji} and ω_{ji} are parameter vectors for *M* and *SF* functions and *eik* is the error term for the observation *k* at zone *i*. We also assume that $q_{Tk} = \sum_i q_{ik}$, which is the total system load. The zonal electricity price and marginal fuel differences in zones resulting from transmission congestion and this effect can be captured using equation (1) for each zone. For this study, j = 3 which includes coal, gas and oil which are the three major marginal fuels in PJM. The "membership functions" points to the probability of each fuel being marginal.

Mathematically this means that,

$0 \leq M_{ji} \leq 1$ and $\sum_{j=1}^{J} M_{ji}=1$ (2)

Now we can rewrite the equation (1) as,

$$P_{ei}\left(q_i, q_T, p_{ci}, p_{gi}, p_{oi}\right) = M_{ci}\left(q_i, q_T, p_{ci}, p_{gi}, p_{oi}\right) SF_{ci}(q_i, q_T, p_{ci}) +$$

$$M_{gi}\left(q_i, q_T, p_{ci}, p_{gi}, p_{oi}\right) SF_{gi}\left(q_i, q_T, p_{gi}\right) + M_{oi}\left(q_i, q_T, p_{ci}, p_{gi}, p_{oi}\right) SF_{oi}(q_i, q_T, p_{oi}) \qquad (3)$$

Where P_{ei} is the price of electricity and P_{ci}, P_{gi}, P_{oi} are the prices of coal, gas, and oil. SF_{ci} , SF_{gi} , SF_{oi} are the partial supply functions associated with fuels coal, gas, and oil respectively. M_{ci}, M_{gi}, M_{oi} are the membership functions indicates the threshold limits of how much coal, gas, or oil is on the margin.

As a robustness check, supply curves were estimated using four models and it was found that the curves are not very different. The four models are: 1. linear curves with fixed thresholds; 2. quadratic curves with fixed thresholds; 3. linear Curves with variable thresholds; 4. quadratic curves with variable thresholds. For this study, we use the linear curves with fixed thresholds. We use linear supply curves to lay down the *SF* and *M* functions so that equation (3) could be used for estimating zonal electricity price.

$$SF_{ji}(q_i, q_T, p_{ji}): P_{ei} = \alpha_{0\ ji} p_{ji} + \alpha_{1\ ji} p_{ji} q_i + \beta_{1\ ji} p_{ji} q_T \tag{4}$$

Where α and β are the coefficients of the supply curve function. The supply function means that zonal electricity price is a linear function of zonal electricity load (q_i) and the total system load (q_T) and also specifies that the coefficients varies by fuel prices. The parameters in the equation (4) can be estimated using the ordinary least squared (OLS) regression method.

While estimating the membership function, it was found that the objective function could not be solved using OLS regression method because it was a non-convex, non-differentiable function having multiple local minima. To solve the optimization problem, Covariance Matrix Adaptation- Evolution Strategy (CMA-ES) which is evolutionary optimization algorithm is used. Figure 3.3 is the supply curve for PECO zone estimated by Sahraei-Ardakani et al [2012]. The estimated supply curve is piecewise linear with three segments associated with the three different fuels (coal, gas and oil; other fuels are generally price-setters in the PJM system). Thresholds based on demand levels where the marginal input fuel switches differentiate the three segments.

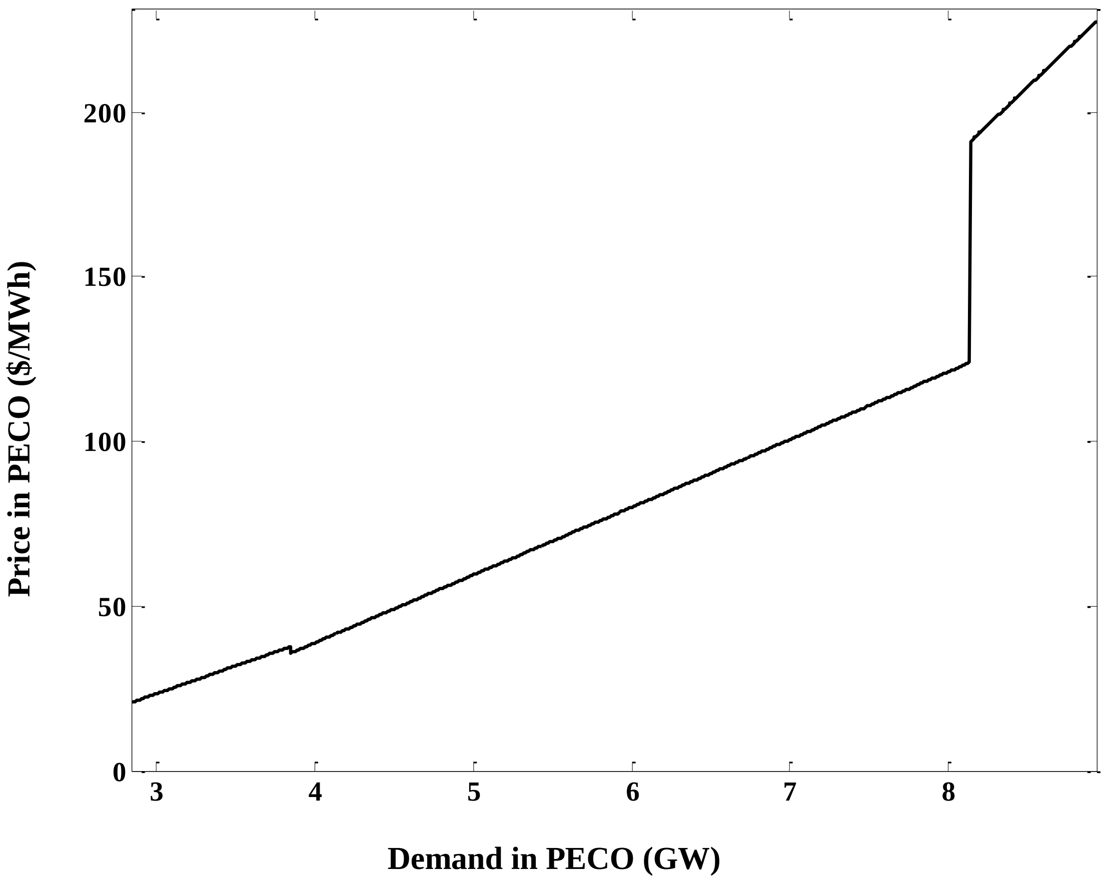

Figure 3.3 Supply curve with transmission constraints for PECO zone estimated by Sahraei-Ardakani et al (2012)

The threshold value when the marginal fuel switches from coal to gas is '3846 MW' and '8140 MW' for gas to oil. There is a small discontinuity when the fuel at the margin changes from coal to gas indicating that marginal cost of producing electricity from gas is comparable to coal plants. This transition point is modeled using a fuzzy logic type of approach (Sahraei-Ardakani et al 2012) where the marginal fuel is actually a mixture of two different fuels, such as coal and gas. Saharei-Ardakani, et al (2012) also suggest that the gap could be widened with changes in relative fuel prices i.e. decline in natural gas prices or increase in coal prices.

Chapter 4

Model Description

A large-scale deployment of CHP units will decrease the demand for grid-provided electricity and thus will decrease location-based prices in wholesale electricity markets. Unlike previous work examining investment incentives for a single CHP unit, or estimating technical potential for CHP deployment, the goal of this paper is to estimate an equilibrium model of CHP deployment, using the Philadelphia area within the PJM electricity market as a case study. Our approach represents an equilibrium model in that it incorporates feedbacks in electricity prices on the net present value of additional CHP installations. In other words, estimating the level of CHP deployment such that additional investments in CHP in that region will not be beneficial or a marginal CHP investment will have a negative net present value.

The zonal electricity price is a function of the zonal demand in the grid and a decrease in demand will decrease the electricity prices. The savings from CHP is a function of the real-time electricity prices, so a decrease in the demand will tend to lower savings, holding the natural gas price constant. The demand reduction depends on the number of CHP units installed. Figure 3 explains the model of equilibrium CHP market deployment.

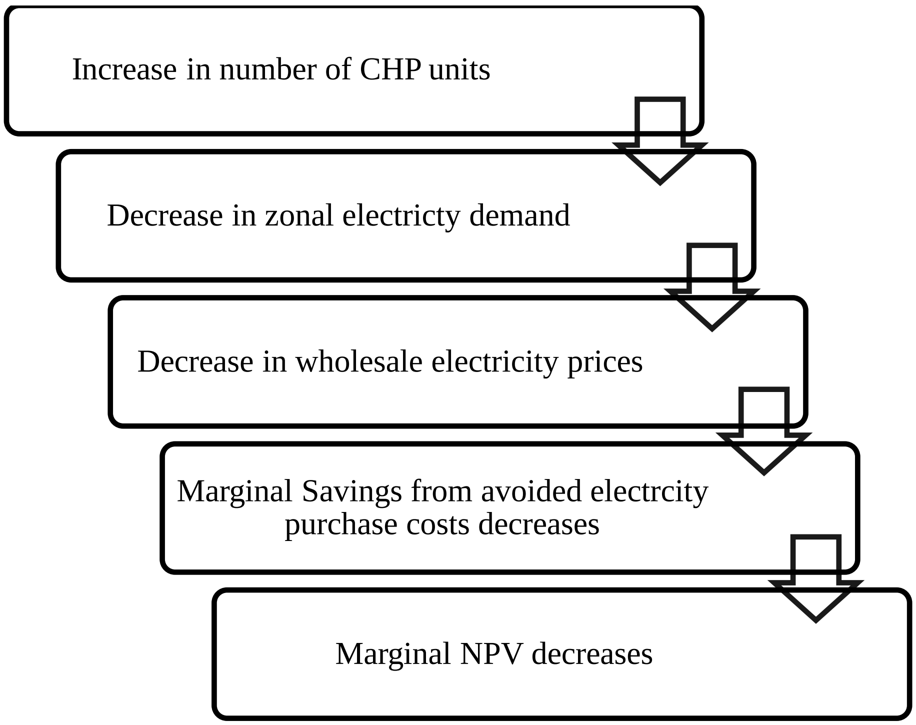

Figure 4.1 - Flowchart of equilibrium CHP deployment model

A single CHP unit will be beneficial to the building owner in the form of avoided costs associated with the additional electricity bought from the utility without a CHP unit. The demand satisfied by a single CHP unit is small relative to the zonal demand, and will not reduce demand sufficiently to change the zonal electricity price. A substantial number of CHP installations will, however, reduce the demand for electricity provided by the grid, thus reducing wholesale electricity prices. The net present value from CHP (i.e., the discounted value of the energy cost savings) is modeled as a function of wholesale electricity prices, and thus decreases with each additional unit of CHP installed. Therefore, incremental CHP deployment will be beneficial until savings from avoided electricity costs can offset the associated cost for CHP installation and operation. Figure 4 illustrates the relation between wholesale electricity price and incremental CHP installation. Q_B is the baseline demand with no CHP units and P_B is the electricity price. As the number of CHP units installed increases (i increasing from 1 to N), the demand in PECO decreases and hence the wholesale electricity price decreases.

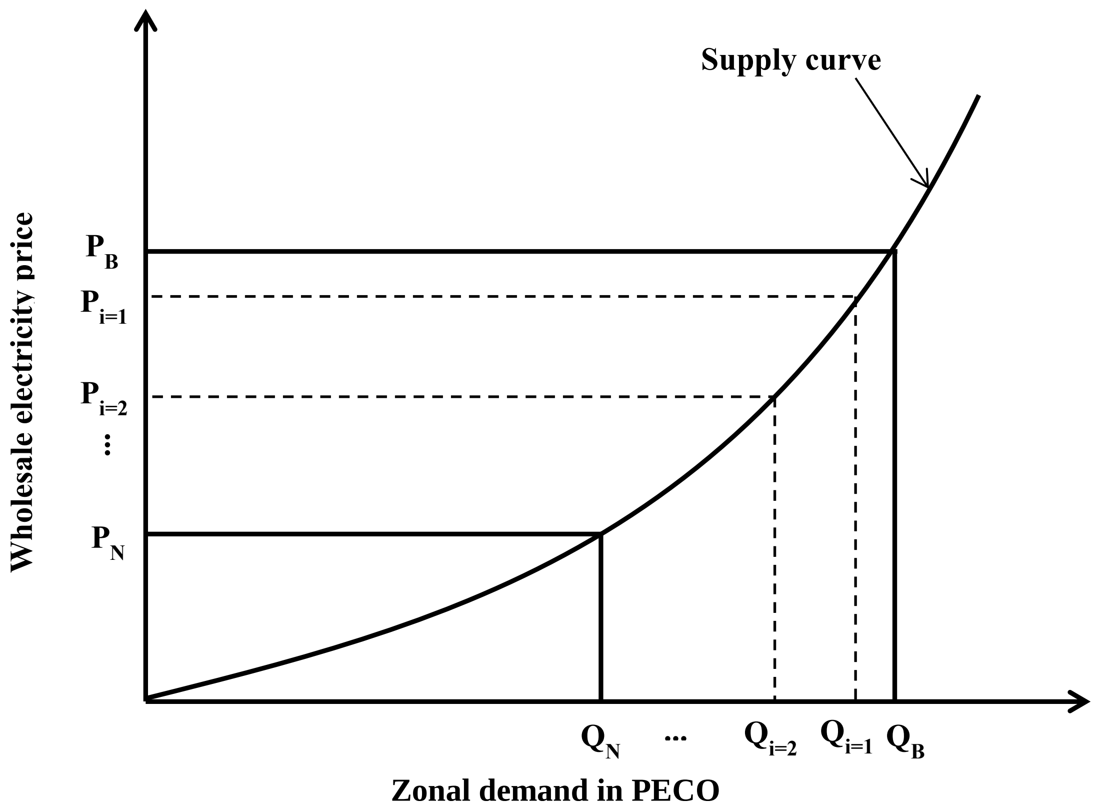

Figure 4.2 - Wholesale electricity prices as a function of zonal demand.

The capital cost for CHP is the upfront cost of the power generating unit and the variable cost includes fuel (natural gas) cost for CHP system operation and the maintenance cost. The gross savings from CHP is the difference between the electricity purchase costs with and without the CHP system. It is assumed that the customers see real-time electricity prices. The equations involved in the cash flow model are,

$$Captail\ Costs, C_i = C_{i,pgu} \tag{5}$$

$$Variable\ Costs, VC_i = C_{i,f} + C_{i,o\&m} \tag{6}$$

$$Gross\ Savings, S_i = P_B * Q_B - P_i * Q_i \tag{7}$$

where *i* denotes the number of CHP units deployed. $C_{i,pgu}$ is the cost of the power generating unit. $C_{i,f}$ is the cost of fuel to run the CHP unit and $C_{i,o\&m}$ is the operating and maintenance costs. Q_B is the demand and P_B is the electricity price without any CHP unit. Q_i is the reduced demand and P_i is the new electricity price with *i* CHP units. So, if *N* CHP units are deployed, the net present value calculated over time *T* with a discount rate of *r* will be,

$$NPV = \sum_{i=1}^{N} \left\{ \sum_{t=0}^{T} \left(\frac{(P_B * Q_B - P_i * Q_i)_t - (C_{i,f} + C_{i,o\&m})_t}{(1+r)^t} \right) - C_{i,pgu} \right\} \tag{8}$$

The savings potential of CHP depends on the zonal electricity price and operation strategy of the CHP unit. At some level of CHP deployment, the savings will be equal to the costs (discounted). At this equilibrium point, a marginal CHP investment will not be beneficial and will have a net present value of zero.

Chapter 5

Data and Methodology

5.1 PJM Generation Interconnection Queue

The PJM Interconnection manages the flow of electricity across all or portions of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. There are 17 zones in total of which 11 zones constitute the Mid-Atlantic region (i.e. excluding COMED, DAY, AEP, APS, DOM, DUQ).

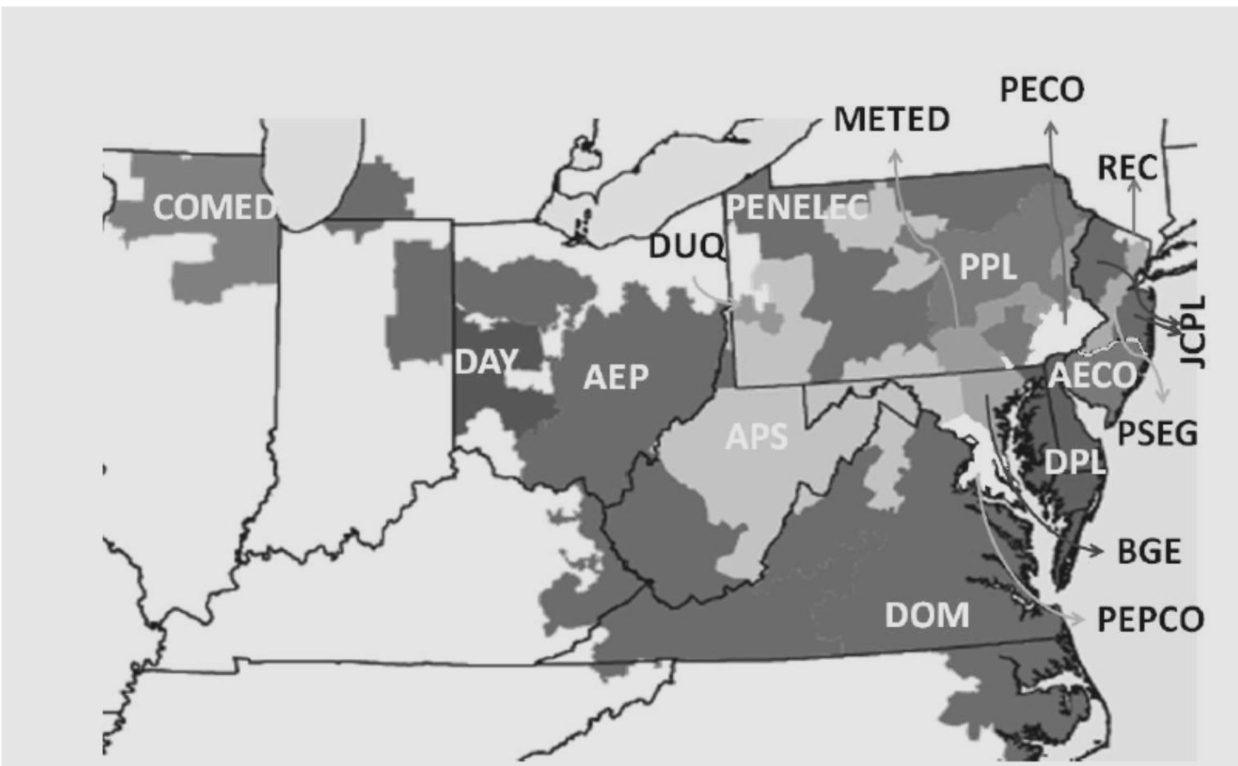

Figure 5.1 – Seventeen zones in the PJM electricity market

The demand for electricity is continuously increasing and to meet this growing demand new capacity resources are interconnected to the existing transmission network. The PJM interconnection queue is a list of new proposed capacity additions to be added to the electricity grid[12]. The interconnection process by PJM ensures the reliability of the new capacity resources. After a request for a new interconnection is submitted, there will be various studies to assess the feasibility, reliability and impact of the new capacity resource. If the results of the above studies are positive, the required infrastructure is built and the capacity resource is interconnected. The requests can be filtered based on their status i.e., 'under study, 'under construction' or 'suspended'. The queue can also be filtered based on the fuel type and the state. We are interested in the new capacity resources in which natural gas is the primary fuel and those that are 'under study' or 'under construction'.

Natural gas consumption for electricity generation in the Mid-Atlantic has increased at a faster rate as compared to the whole of U.S. The share of natural gas consumption for electricity generation has increased from 10% in the late 1990's to 25% in 2010. The recent discovery of Marcellus shale and the rapid increase in drilling activities will increase the supply of natural gas. We try to estimate the future natural gas consumption for electricity generation in the Mid-Atlantic region. From the PJM interconnection queue, we can estimate the total capacity of the plants fuelled by natural gas that are to be interconnected in the future.

The Mid-Atlantic region as defined by the Mid-Atlantic Clean Energy Applications Center includes Pennsylvania, New Jersey, Delaware, Maryland, Virginia, West Virginia and District of Columbia.

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[12] It can be accessed at http://www.pjm.com/planning/generation-interconnection/generation-queue-active.aspx. It should be noted that new requests for interconnection is a continuous process and the interconnection is updated frequently. For this study, the queue was last accessed April 2012.

Figure 5.2 - Mid-Atlantic region. Source: Mid-Atlantic Clean Energy Applications Center

By filtering the interconnection queue based on state and fuel type (natural gas) we have a list of planned gas fired capacity additions in the Mid-Atlantic region[13]. There are 77 requests in total of which 66 are under study (32376 MW) and 11 are under construction (2952MW). Using weighted average heat rate and capacity factor of existing generators (eGRid 2007) it was estimated that 32376 MW of capacity corresponds 530 million cubic feet of natural gas.

We try to match this estimate with the natural gas consumption projections in electric sector in the Mid-Atlantic region[14]. According to the U.S. Energy Information Administration census regions, Mid-Atlantic covers the states of New York, New Jersey and Pennsylvania and the states of Virginia, West Virginia, Delaware, Maryland and District of Colombia comes under the census division South Atlantic along with North Carolina, South Carolina, Georgia and Florida. All the energy projections in the Annual Energy Outlook 2011 are based on this census division. This is different from the definition used in this study. According to Annual Energy

[13] See appendix for details on the interconnection requests which are 'under study' and 'under construction as of April 2011.

[14] Annual Energy Outlook 2011, Energy Information Administration

Outlook 2011, Mid-Atlantic region had a growth rate of 0.7% and South Atlantic had a growth rate of 0.3% for natural gas consumption in electricity sector until 2035.

Since there is a mismatch in definition of Mid-Atlantic census division, natural gas deliveries to electricity generation data for the states in Mid-Atlantic and South-Atlantic census division (U.S. EIA definition) were collected between 1997 and 2010[15]. Natural gas consumption for electricity generation in each of these states was then projected consumption till 2016 using their respective growth rates of 0.7% and 0.3%. We projected till 2016 because the 'in-service' dates for all the proposed capacity additions in the PJM interconnection queue is until 2016. The assumption here is that the percentage contribution by each of these states in the year 2010 is going to be the same in 2016. Now, we have individual states future projections and by summing up the consumption for the states (i.e. PA, NJ, DE, MD, VA, WV) we get the projected natural gas consumption for electricity generation to be about 660 million cubic feet in the year 2016.

5.2 Description of case study

This study focuses on the deployment of single-user CHP among various types of commercial buildings in Philadelphia, in Southeastern Pennsylvania. A typical single-user building CHP installation would represent a few megawatts or less of power generation capacity. Larger installations (tens of megawatts), as would be typical of industrial applications, are not considered in our analysis. Philadelphia falls in the PECO zone of the PJM electricity market. Primarily due to transmission constraints, prices in the PECO zone have historically been higher than average for the PJM market as a whole. Data on Philadelphia's commercial building stock

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[15] State Profiles and Energy Estimates, Energy Information Administration. http://www.eia.gov/beta/state/seds/

was obtained from the CoStar database (Econsult Corporation 2011). While the database does not capture the universe of commercial buildings in Philadelphia, it does provide the best available representation of the region's commercial building stock and the distribution of building stock among different building types. Table 5.1 shows the number of buildings in eight types of commercial buildings in Philadelphia.

Table 5.1 - Commercial buildings stock in Philadelphia

Rank[1]	**Building Type**	**Number of buildings**
1	Hospital	50
2	Hotel	74
3	Restaurant	29
4	Office	284
5	Supermarket	51
6	School	63
7	Motel	22
8	Warehouse	439

[1] Priority rankings for CHP deployment in different types of commercial buildings developed by Lawrence Berkley National Laboratory(Lawrence Berkeley National Lab 1991)

5.3 Building Hourly loads

Comprehensive energy use profiles of buildings are not commonly recorded. The Building - CHP Screening tool (BCHP), developed by Oak Ridge National Lab, was used to develop hourly electricity, heating and cooling demand profiles for the eight types of buildings under study (Oak Ridge National Lab 2005). The BCHP tool estimates energy demand profiles for various types of commercial buildings based on user-defined parameters such as building dimensions, location and occupancy schedules. Input parameters for the eight types of commercial building were obtained from by U.S Department of Energy Commercial Reference Building Models of the National Building Stock (National Renewable Energy Lab 2011). For each type of building, three scenarios were developed – Baseline without CHP, CHP system following thermal loads (CHP-FTL) and CHP system following electrical load (CHP-FEL) (P. J. Mago, Fumo, and Chamra 2009).

The baseline scenario is a reference case without any CHP units installed. For CHP following thermal load, the system is operated to maximize the delivery of thermal load required at the site for various processes such as space heating, space cooling, dehumidification and other site related applications. In the process of operating the CHP unit to meet thermal demands, some amount of electricity is generated. The recovered heat from the CHP system will displace much, if not all, of the fossil fuel required that would have been required in a conventional boiler for the site and the electricity produced meets some of the demand. For CHP following electric load, the CHP system operates to meet the site's electricity demand. In general, this is not economical because onsite generation of electricity from CHP cannot compete with central station generation of electricity on a cost per kWh basis. In addition, the recovered heat does not match with the thermal demand; hence, a complete advantage of the fuel savings is not realized.

Table 5.2 provides the area, building occupancy schedule and hours of generator operation used in the BCPH tool for each type of building. The generators were assumed to be operated when the electricity demand was high. The periods of high demand for each type of building was estimated based on the baseline case simulation results.

Table 5.2 - Buildings occupancy schedule and peak-electricity demand periods

Building type	**Area (m^2)**	**Hours of generator operation**	**Building occupancy schedule**
Hospital	22422	8 am to 6 pm	weekdays - 24 hours weekends - 24 hours
Large Office	46320	9 am to 3 pm	weekdays - 7 am to 8 pm weekends - closed
Large Hotel	11345	7 am to 2pm, 6 pm to 9 pm	weekdays - 24 hours weekends - 24 hours
Motel	4014	7 am to 11 am, 7 pm to 9 pm	weekdays - 24 hours weekends - 24 hours
Supermarket	4181	8 am to 5 pm	weekdays - 8 am to 8 pm weekends - 8 am to 8 pm
Restaurant	511	10 am to 7 pm	weekdays - 9 am to midnight weekends - 9 am to midnight
School	19572	10 am to 2 pm	weekdays - 8 am to 10 pm weekends - closed
Warehouse	4835	9 am to 4 pm	weekdays - 8 am to 6 pm weekends - closed

Table 5.3 compares the energy intensities from the BCHP tool and the energy intensities for buildings in Mid-Atlantic region obtained from the Commercial Building Energy Consumption Survey (Energy Information Administration 2006). The CBECS is a nation-wide survey of energy consumption of commercial buildings in the U.S. Energy intensities for certain building types were missing under the Mid-Atlantic census division. The missing values were obtained from Buildings Energy Data Book (US Department of Energy 2011). There are some substantial differences between the energy intensities from CBECS and from BCHP. In particular, BCHP's estimates of energy intensity for supermarkets and warehouses are more than 20 percent higher than estimates from CBECS.

Table 5.3 - Energy Intensity Validation

Building Type	**Energy Intensity from CBECS (1000 BTU/SF)**	**Energy Intensity from BCHP (1000 BTU/SF)**
Hospital	214	201
Large Office	81	64
Large Hotel	110	113
Small Hotel/Motel	75	102
Supermarket	74	89
Restaurant	198	172
Secondary School	80	69
Warehouse	49	72

The BCHP tool calculates the generator sizing using the DOE-2 sizing run. The sizing depends on the maximum load for each building type since the generator is modeled to operate during periods of high demand. Table 5.4 gives the generator sizing for each building type.

Table 5.4 - Generator sizing for each type of building

Building Type	**Generator Size(kW)**
Hospital	1500
Large Hotel	420
Restaurant	30
Large Office	1820
Supermarket	200
School	550
Small Hotel/Motel	125
Warehouse/Flex- industrial	100

The costs associated with a CHP system include capital costs, and operating costs such as fuel and maintenance. It is assumed that all the CHP units run on natural gas. Average cost estimates for a typical CHP unit were obtained from the U.S. Environmental Protection Agency (Environmental Protection Agency 2008b). Table 5.5 gives an average capital and operation and maintenance cost for a typical CHP system. The natural gas consumption under each operational strategy is obtained from BCHP tool to estimate the fuel cost.

Table 5.5 - Average cost estimates for a typical CHP system

Capital Cost ($/kW)	1200
Incremental O&M cost ($/kWh)	0.01

CHP units deployment is simulated according to the priority rankings developed by the Lawrence Berkley National Laboratory (Lawrence Berkeley National Lab 1991). Our analysis assumes that CHP units will be installed at the most advantageous sites first (according to the LBNL rankings) followed by deployment at progressively less advantageous sites. It is assumed that CHP units will be installed first in all the hospitals (which are ranked the most advantageous single-use cases for CHP) followed by hotels and so on, as shown in Table 5.1. Reflecting a limitation in the CoStar data, we assume that building types have homogeneous thermal and electric load profiles within type and those demand profiles are well-represented by the BCHP tool. The BCHP tool is utilized to generate hourly CHP usage profiles for each building type. For each deployment scenario, hourly CHP usage is aggregated across all simulated CHP installations; this represents the electricity demand taken off the PJM electric grid in each hour. Thus, the hourly demand in the PECO zone of the PJM electricity markets is reduced (using demand in 2010 as the baseline) with every CHP unit deployed and estimate the zonal price change with incremental CHP units deployed. Figure 5.3 shows the load duration curves for the baseline case and the reduced demand with CHP units following thermal load (FTL) and electric load (FEL) for all 1,012 CHP units corresponding to the commercial building stock represented in the CoStar database. CHP-FEL has more on-site generation compared to CHP-FTL and hence higher displacement of grid-provided electricity.

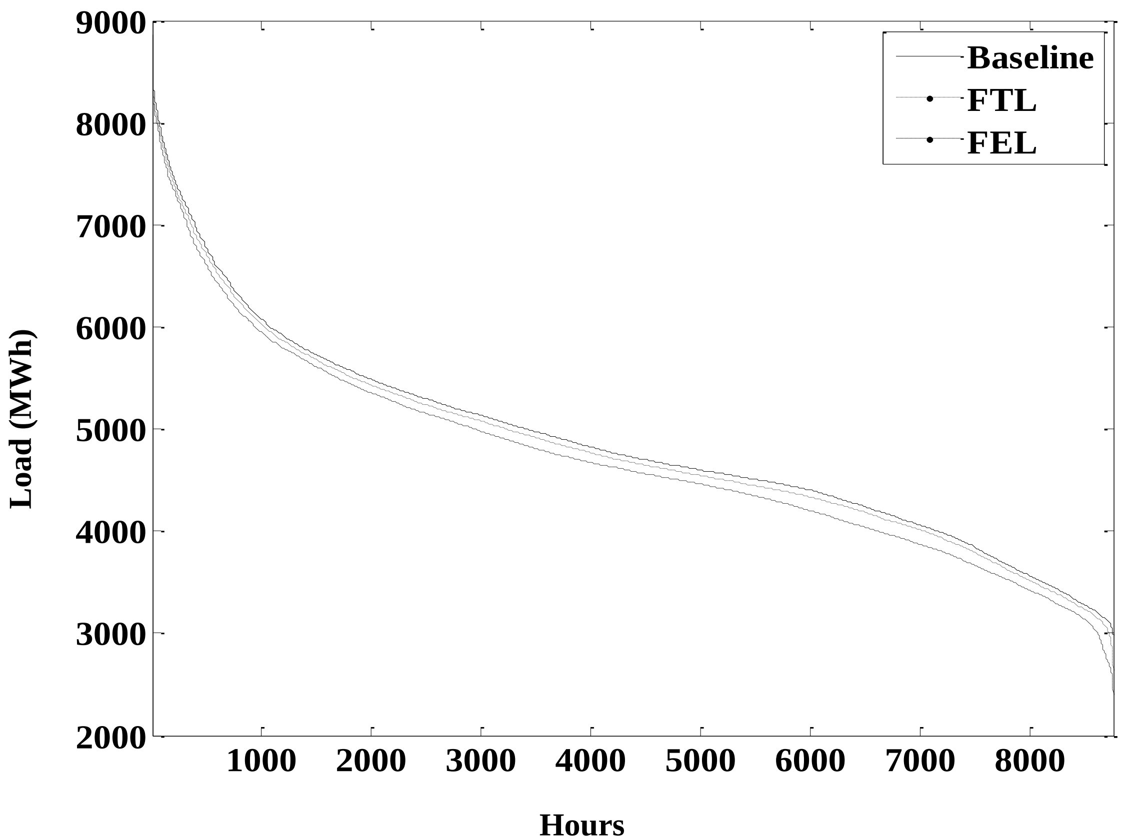

Figure 5.3 - Load duration curves for a) Baseline demand, b) CHP-FTL, c) CHP- FEL

Reductions in grid-provided electricity, however, are reasonably modest in magnitude no matter what operational strategy is modeled (FEL or FTL). The average demand for electricity from the grid reduces from 4879 MW (baseline) to 4820 MW in case of CHP-FTL and 4720

MW in case of CHP-FEL. The standard deviation for base line, CHP-FTL and CHP-FEL are 1011, 1009 and 1025 MW respectively.

Large-scale CHP deployment might affect both natural gas and electricity prices, in opposite directions (since CHP would increase demand for natural gas while decreasing demand for grid-provided electricity). Natural gas prices affect the operating costs of CHP and also the zonal electricity prices (hence savings). The uncertainty in the price of natural gas is captured using three gas price scenarios ($2/mmBtu, $4/ mmBtu and $8/ mmBtu). Prices for coal and oil (other fuels utilized in the Philadelphia region) are assumed to remain constant (coal - $2 / mmBtu, oil – $10.667/ mmBtu). The net present value on a CHP investment is calculated for three natural gas price scenarios for a 10-year period with a discount rate 8 percent. The return on investment is calculated assuming first year (2010) savings are achieved every year.

Chapter 6

Results

This study looked at two research questions, the impact of new gas fired generators on electricity prices in PECO zone and evaluating the equilibrium level of CHP deployment in the Philadelphia region. The supply curve model for PECO developed in section 4.2 is used to assess the impact of a large-scale adoption of CHP on zonal electricity prices. This section discusses the results of the analysis.

5.1 Impact of new gas fired capacity on electricity prices in PECO zone

Natural gas fired generators are more efficient, has lesser heat rates and has fewer CO_2 emissions compared to coal and oil fired generators. The recent discovery of Marcellus shale gas reserves has led to a decrease in market gas prices in the Mid-Atlantic region. Along with the low natural gas prices, environmental regulations related to decreasing CO_2 emissions will tend to have a rise in natural gas fuelled capacity investments. Figure 5.1 is the short run marginal cost curve for PECO zone with and without the new gas fired capacity.

The new gas projects shifts the marginal cost curve outward with more natural gas generators meeting the peak demand replacing some oil generators. This implies that electricity prices during peak demand will decrease since oil generators that have higher marginal costs are replaced with by lower marginal cost natural gas generators.

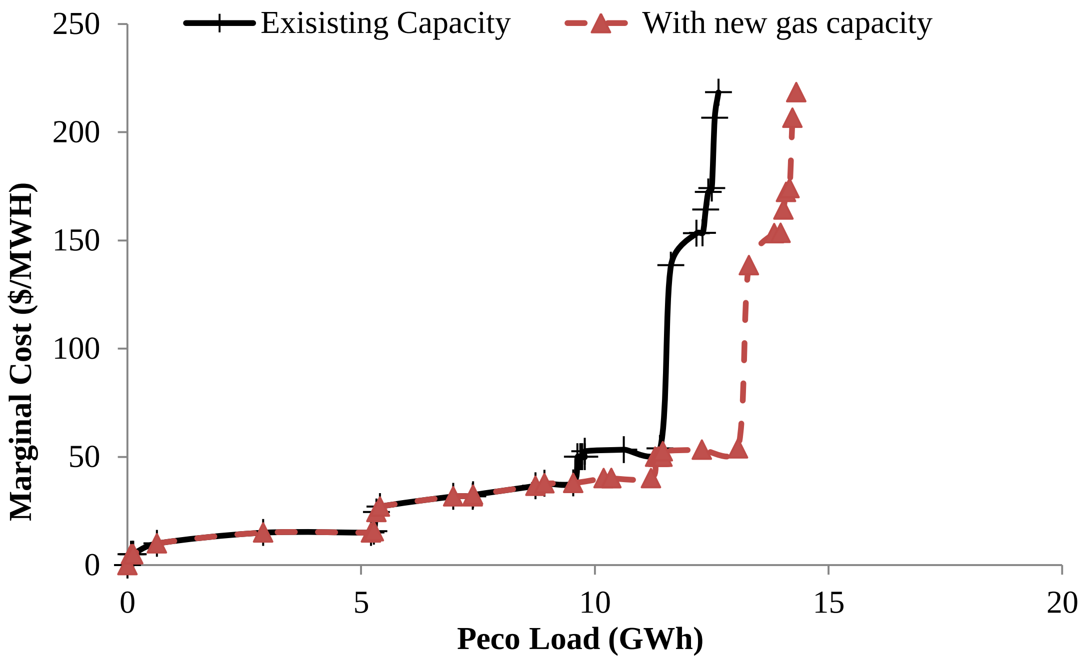

Figure 6.1 - Short run marginal cost curve for PECO zone with and without new gas capacity

According to the PJM Generation Interconnection queue, there are four planned gas fired capacity additions in the PECO zone with a total capacity of 1666 MW (see appendix for details). All the projects were 'under study'. Apart from the nameplate capacity, there was no other information on the heat rate or the capacity factor of these new additions. However, to incorporate the new natural gas capacity in economic dispatch model we need to have an estimate of the marginal costs or the heat rates. For this study, we assume that all the new gas fired generators are fairly efficient and has an average heat rate of about 8000(Blumsack 2010). We can calculate the marginal costs of the new generators using the assumed heat rate.

To incorporate the new additions, we add a region in the piecewise supply curve when natural gas is in the margin to represent the new projects. It should be noted that this might not be the accurate way since incorporating new generators may change the power flow in PJM electricity market. However, the assumption here is that 1666 MW capacity is not significant compared to the existing capacity in the PJM electricity market.

Figure 5.2 is the supply curve for PECO zone with the new gas plants. This supply curve includes transmission constraints, as discussed in section 3.2, compared to figure 5.1, which is estimated using data from eGRID. It can be seen that there is a horizontal line, which represents the new projects. The line is horizontal since the marginal costs for all the planned projects are same, which is because of same assumed heat rate of 8000 for all projects.

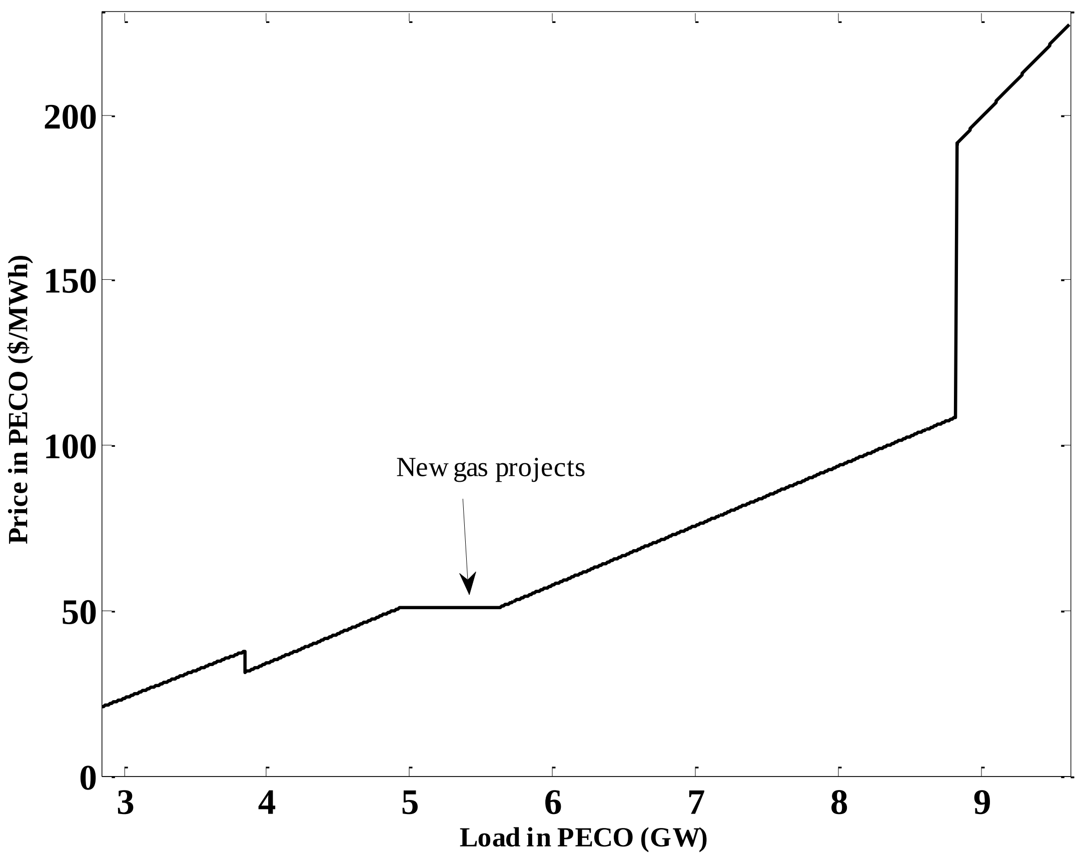

Figure 6.2 - Supply Curve for PECO zone with the new gas plants.

The new gas projects with a lower marginal cost will be dispatched before the oil generators reducing the electricity prices at certain hours when the oil generators are in the margin. We try to capture this effect of decrease in electricity price in PECO zone using the supply curve model with transmission constraints estimated in section 3. We fit the original supply curves with hourly loads for a year and get a price duration curve, which gives the electricity price distribution over a year. The price duration curves were developed for 2006 and 2010 load data obtained from PJM[16]. The peak electricity prices were high in 2006 as compared to 2010. Figure 6.3 is the load distribution for the years 2006 and 2010 in PECO; figure 6.3(a) shows the peak load distribution and 2006 has a higher peak demand compared to 2010.

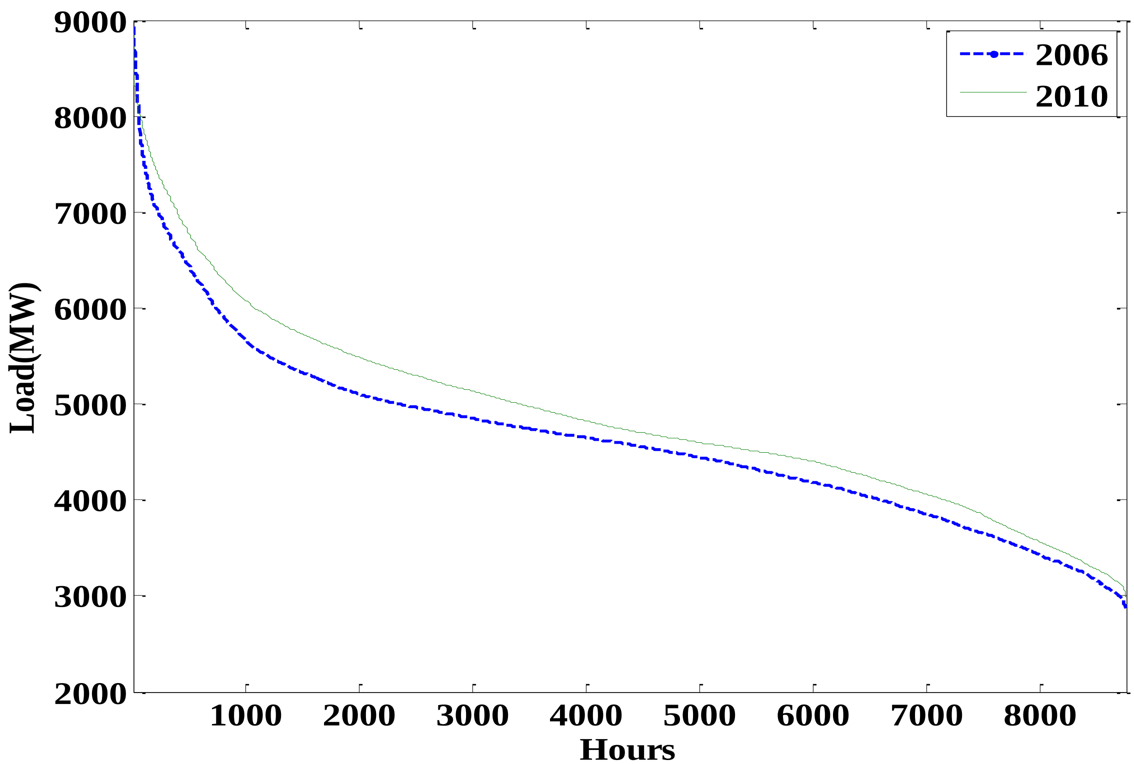

Figure 6.3 - Load duration curve for years 2006 and 2010

[16] See Historical Metered Load data, PJM Interconnection.http://pjm.com/markets-and-operations/ops-analysis/historical-load-data.aspx

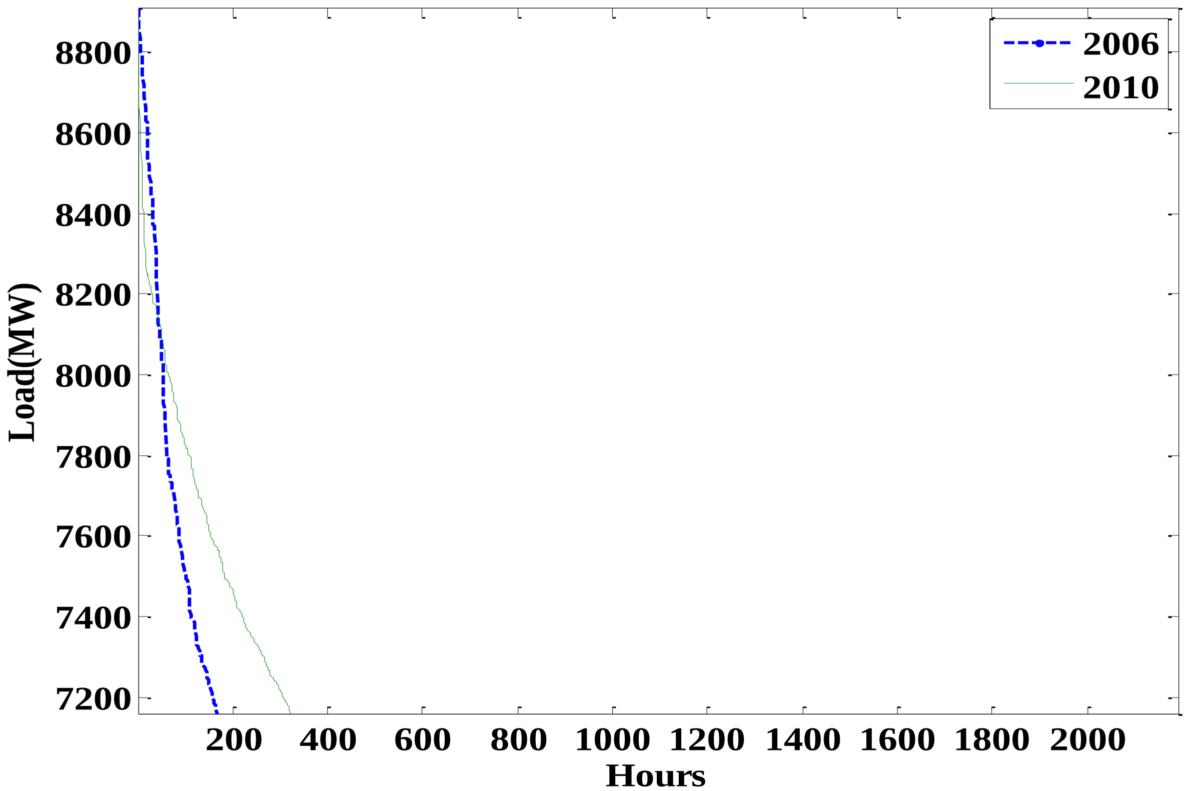

Figure 6.3(a) - Peak load duration curve for years 2006 and 2010

The price reduction effect depends on the natural gas prices and we capture this by developing price distribution curves for two natural gas price scenarios; $4/mm Btu and $8/mm Btu. The results are presented as price duration curves and it can be seen that there is a price reduction in all four scenarios (figures 6.4 to 6.7). As discussed earlier, the price reduction is a result of the new gas capacity replacing the high priced oil generators during periods of peak demand. However, there is a distinction in the magnitude of price reduction and the number of hours in which there is a price reduction between the four scenarios. The price reduction trends depend on a combination of two factors; the electricity demand distribution and the marginal costs of the new gas capacity (which is a function of the natural gas price).

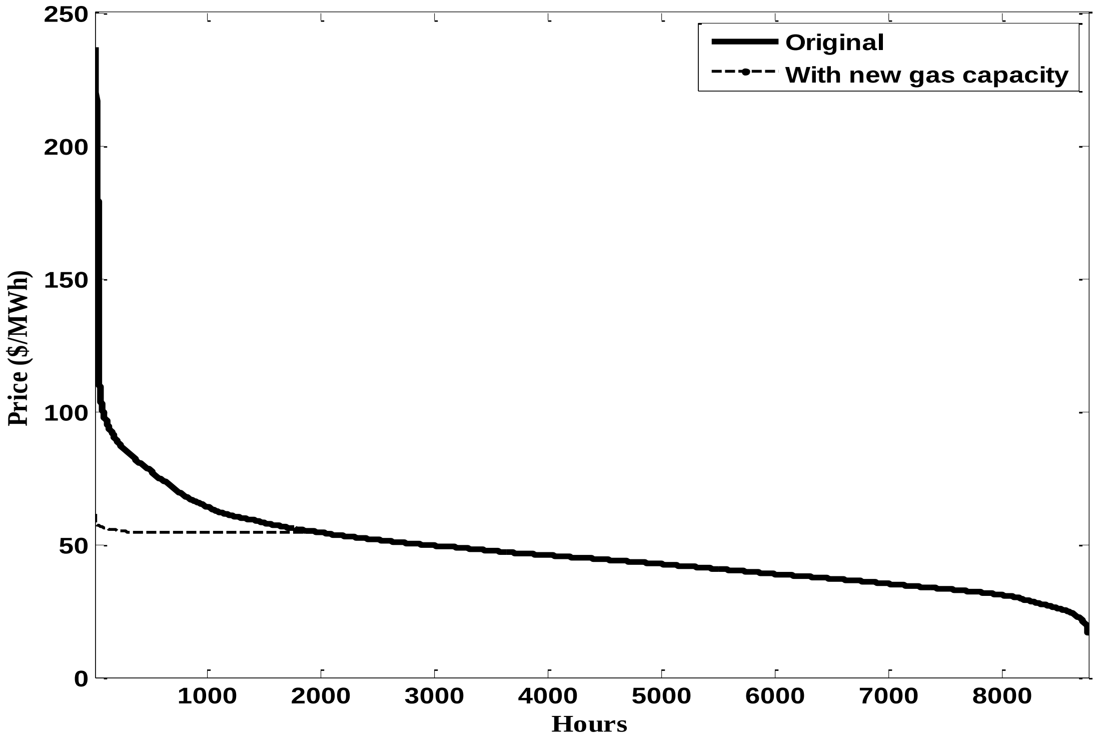

Figure 6.4 - Price duration curve for PECO with 2006 hourly loads, gas price - $8 mm/Btu

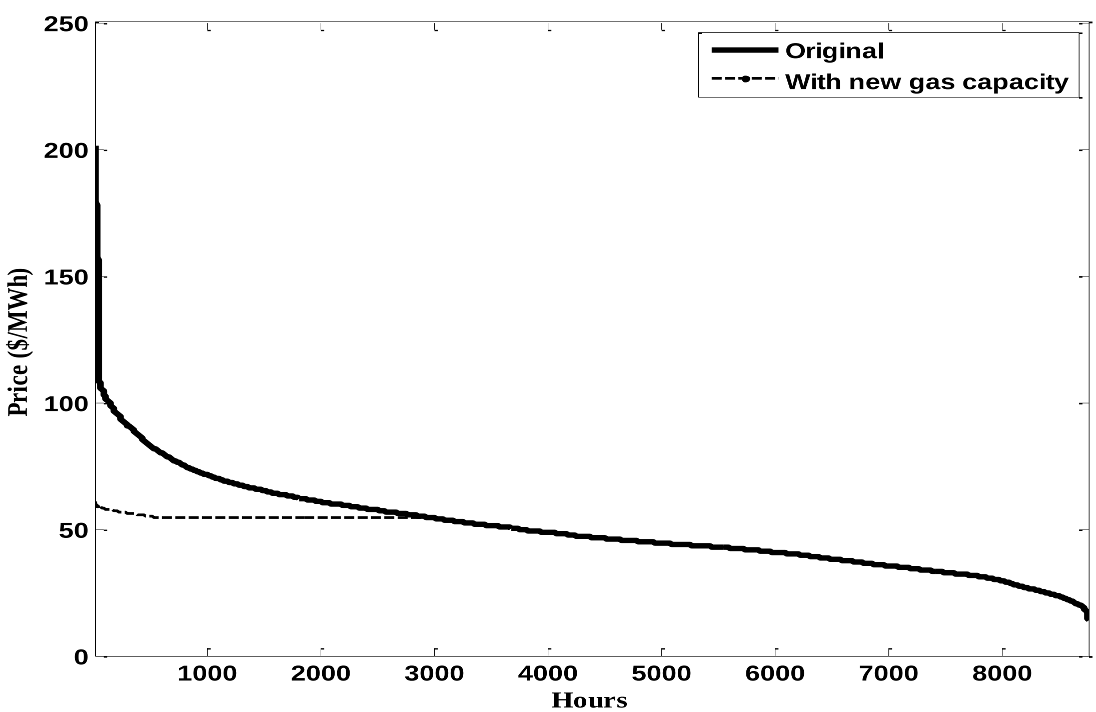

Figure 6.5 - Price duration curve for PECO with 2010 hourly loads, gas price - $8/mm Btu

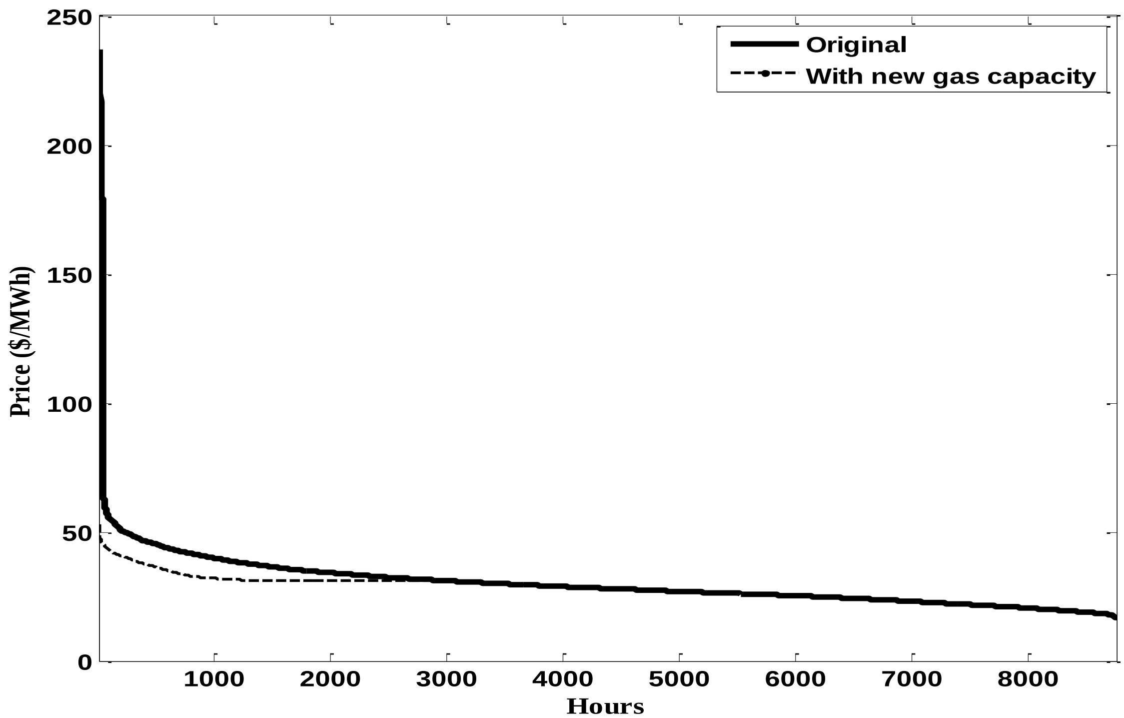

Figure 6.6 - Price duration curve for PECO with 2006 hourly loads, gas price - $4/mm Btu

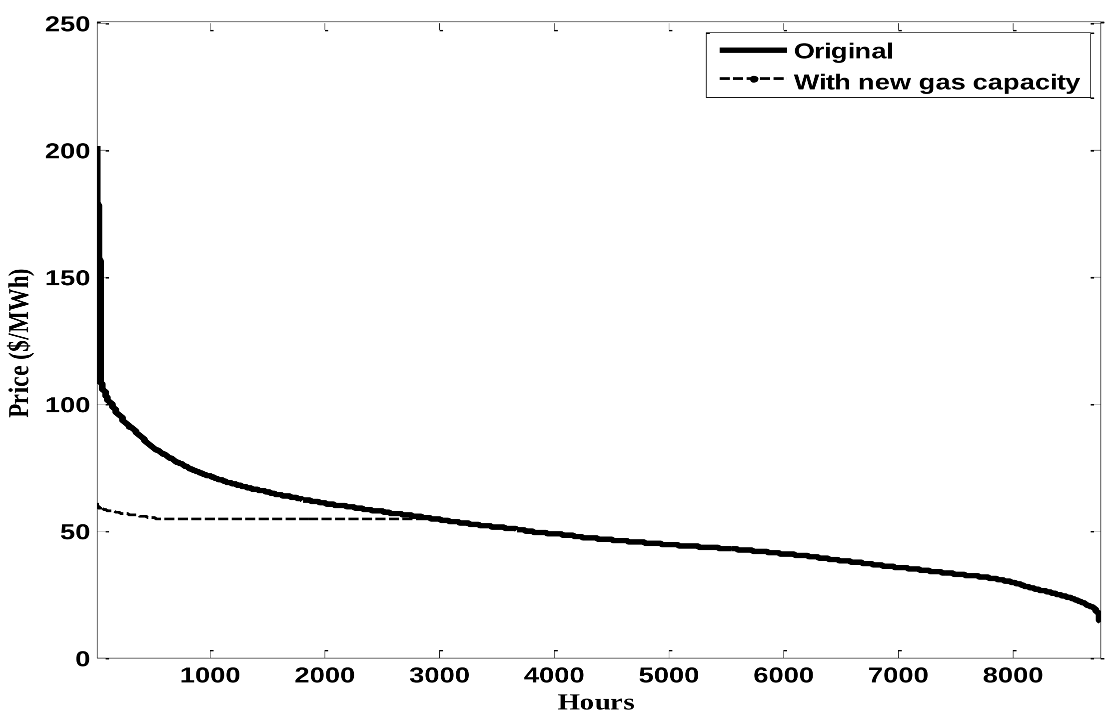

Figure 6.7 - Price duration curve for PECO with 2010 hourly loads, gas price - $4/mm Btu

Fig 6.8 shows the price reduction following the additional gas capacity in each hour for all four cases[17]. The plot shows the zonal electricity price distribution for a year. There is a price reduction for about 2500 hours in 2010 and about 1700 hours in 2006. Since the electricity demand in 2010 was higher than the demand in 2006 except for about 100 hours (refer figure 6.3 and 6.3a) there is a price reduction for a larger number of hours in 2010 as compared to 2006. The natural gas price does not affect the number of hours in which there is price reduction.

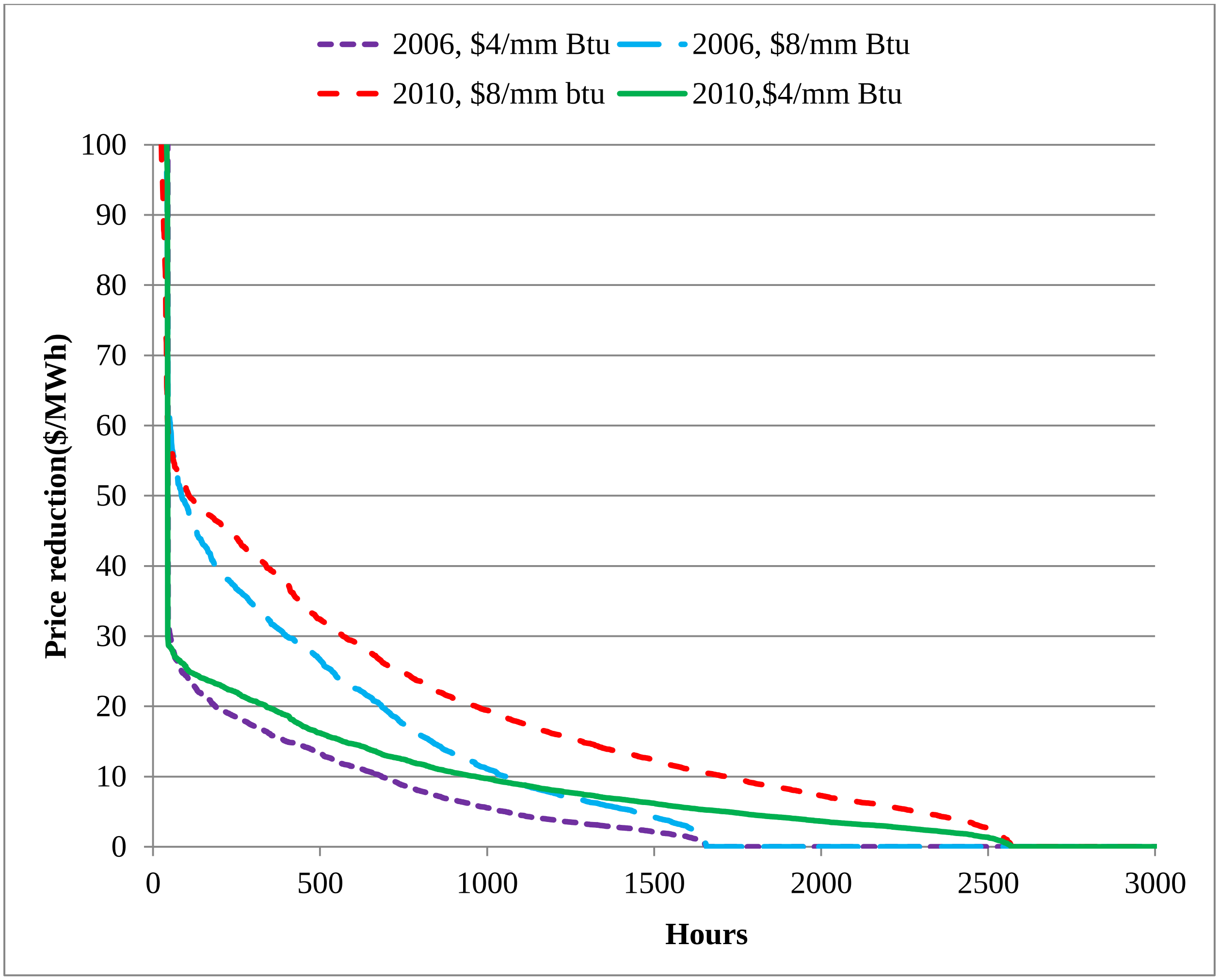

Figure 6.8 - Hourly Price reduction in PECO

[17] It should be noted that the maximum value of y-axis and x-axis have been reduced for better understanding of the plot.

The highest reduction in maximum electricity price was observed in 2006 with natural gas price of $4/mm Btu and the lowest reduction was observed in 2010 with a natural gas price of $8/mm Btu. It should also be noted that with a higher natural gas price there would be higher price reductions as seen in figure 6.8. Table 6.1 and table 6.2 shows the maximum and the average electricity price for the four cases along with the baseline case.

Table 6.1 - Maximum and average price with natural gas price of $8/ mm Btu

	Year	Maximum Price ($/MWh)	Average Price ($/MWh)
Original	2006	236.87	53.34
	2010	201.11	56.84
New gas capacity	2006	69.96	49.21
	2010	69.52	50.92

Table 6.2 - Maximum and average price with natural gas price of $4/ mm Btu

	Year	Maximum Price ($/MWh)	Average Price ($/MWh)
Original	2006	236.87	30.4
	2010	201.11	30.88
New gas capacity	2006	53.08	27.84
	2010	56.02	27.51

5.2 Economic potential for CHP in Philadelphia

The technical potential for CHP in Philadelphia is substantial. Incremental installations of CHP, however, reduce the demand for electricity provided by the grid, thus reducing wholesale electricity prices. The return on incremental investment, a function of the electricity prices, decreases as the number of CHP units installed increases. Figure 6.9 shows the price duration curves corresponding to the load duration curves in figure 5.3.

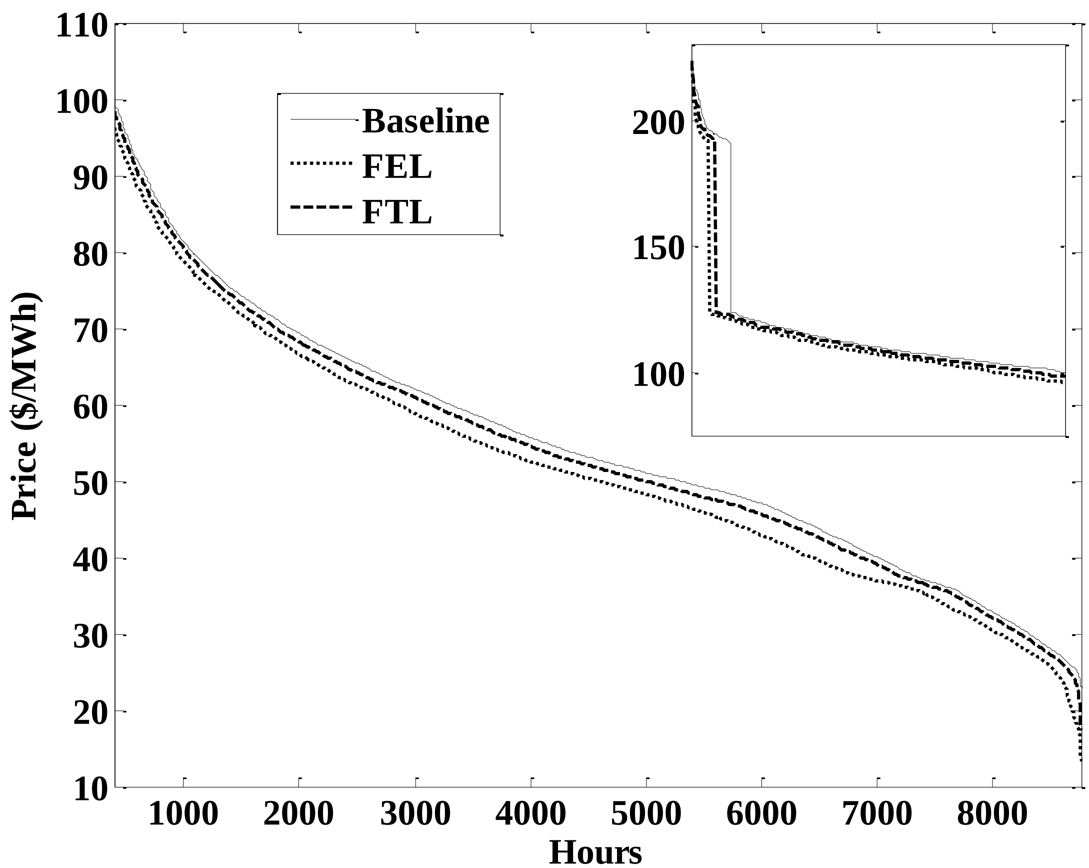

Figure 6.9 - Price duration curves for a) Baseline demand, b) CHP-FEL, c) CHP- FTL. Fuel prices are assumed to be, coal - $2 / mmBtu, gas - $7/mmBtu, oil – $10.667/ mmBtu.

With natural gas prices of $2/mmBtu and $4/mmBtu (and $2/mmBtu coal price) there is no substantial differences in the effects on the price duration curve arising from 1,012 CHP installations operated according to FEL and FTL. The results suggest that electricity price reduction (and savings) is sensitive to natural gas prices and the operational strategy of CHP. In particular, the impacts of CHP adoption will have larger impacts on the electricity price duration curve under high gas-price scenarios. This is due primarily to the reductions in peak-time electricity demand. Also, operating CHP units in FEL mode has a larger impact on the electricity price duration curve (through larger reductions in demand for grid-provided electricity) than does operating CHP units in FTL mode.

The gross savings from a CHP unit are the avoided costs from purchasing additional electricity bought from the utility without a CHP unit (net savings would incorporate the cost of natural gas to fuel the CHP unit, plus other operational or maintenance costs). As shown in figure 5 and 6, there will be a decrease in demand and price every hour in a year. The hourly savings is estimated using equation (3) and aggregated it to get yearly savings from avoided electricity costs. Figures 6.10, 6.11 and 6.12 show gross electricity cost savings as a function of the number of CHP units deployed and the operational strategy (FEL or FTL). The figures calculate gross electricity cost savings over a 10-year period under three gas-price scenarios ($2/mmBtu, $4/mmBtu and $8/mmBtu). Higher savings were achieved with higher natural gas price ($8/mmBtu) as there will be more savings from avoided electricity costs as compared to a $2/mmBtu natural gas price. The savings from CHP-FEL is higher since there will be more onsite electricity generation, hence higher avoided electricity costs as compared to CHP-FTL. The total savings curve tends to flatten as number of CHP unit deployed increases indicating that the incremental savings from CHP decreases.

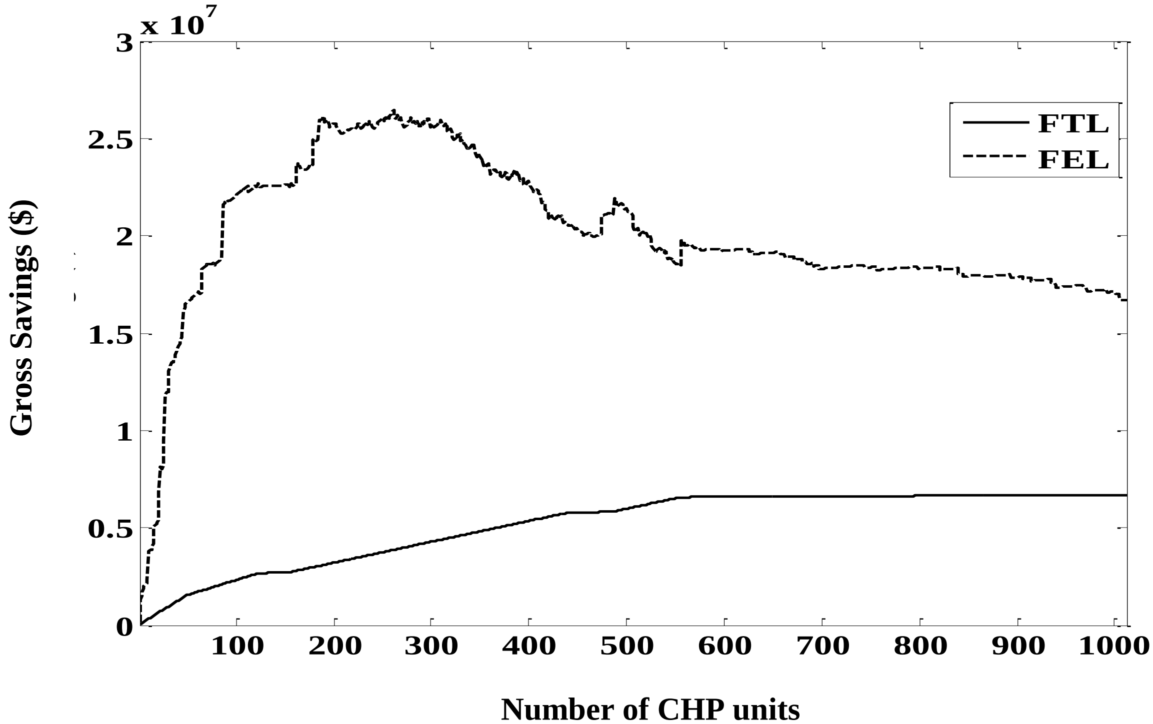

Figure 6.10 - Total Savings with a $2/mmBtu natural gas price

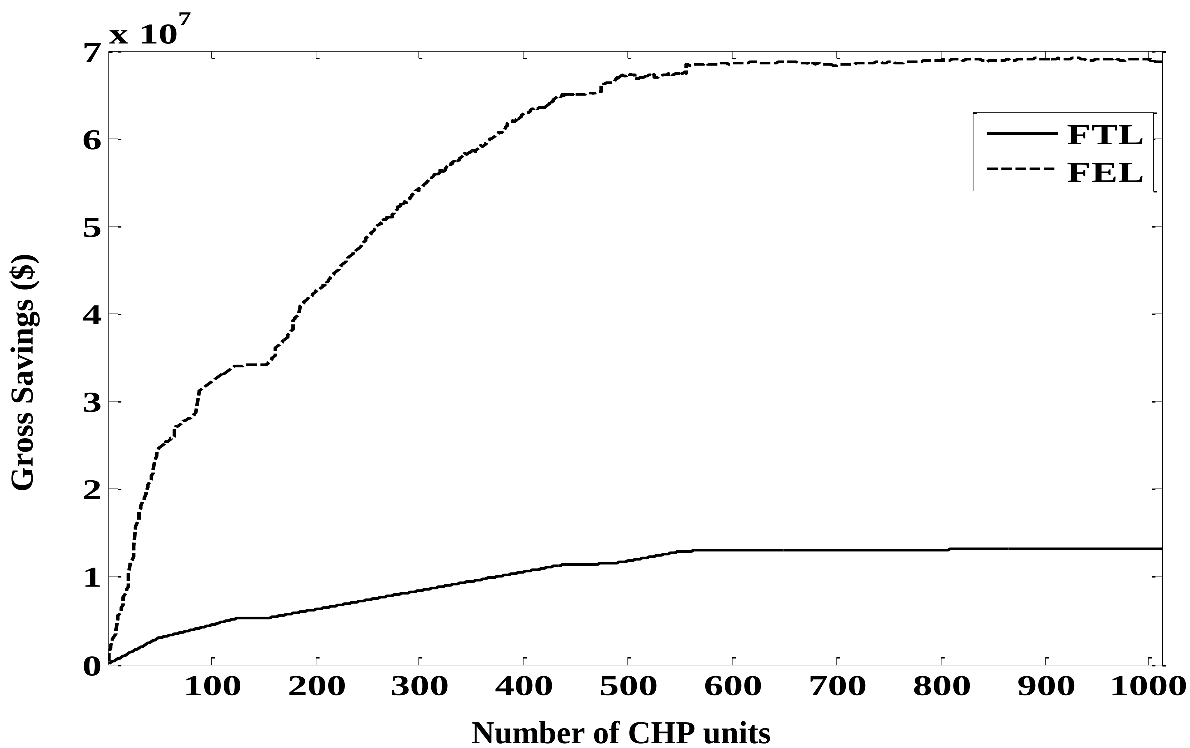

Figure 6.11 - Total Savings with a $4/mmBtu natural gas price

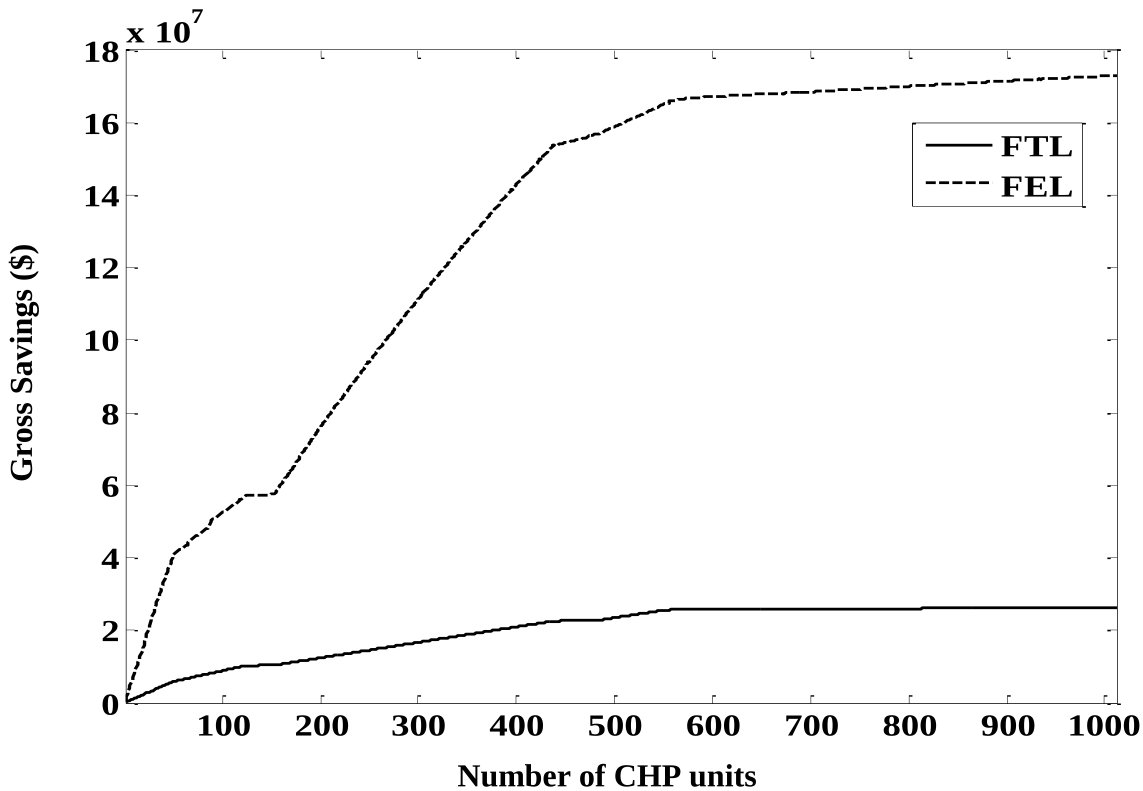

Figure 6.12 - Total Savings with a $8/mmBtu natural gas price

After about 300 CHP installations, the savings from CHP-FEL decreases for a $2/mmBtu natural gas price (figure 7). This happens because of low zonal electricity prices resulting because of substantial demand taken off the grid coupled with lower natural gas price. At this point, the price of electricity from the utility is cheaper than generating on-site electricity from CHP. This means that any further deployment of CHP-FEL will not be beneficial to the building owner.

Figures 6.13, 6.14 and 6.15 show the incremental energy cost savings which is termed as "marginal savings" for CHP installations, for the three natural gas price scenarios and the two CHP operation strategies. The marginal savings from CHP-FTL decreases with increase in the number of CHP units for all three price scenarios. Marginal savings from CHP-FEL increases for deployment in hospitals (the first 50 CHP units), since the savings in grid-purchased electricity is large compared to the impact on LMPs in the PECO zone. As less advantageous CHP units are deployed, the marginal savings begins to decrease more rapidly. Marginal savings flattens out once roughly 100 to 300 CHP units are deployed, reflecting a combination of lower reductions in the demand for grid-provided electricity and a shift inwards of electricity demand towards the less-elastic portion of the PECO supply curve.

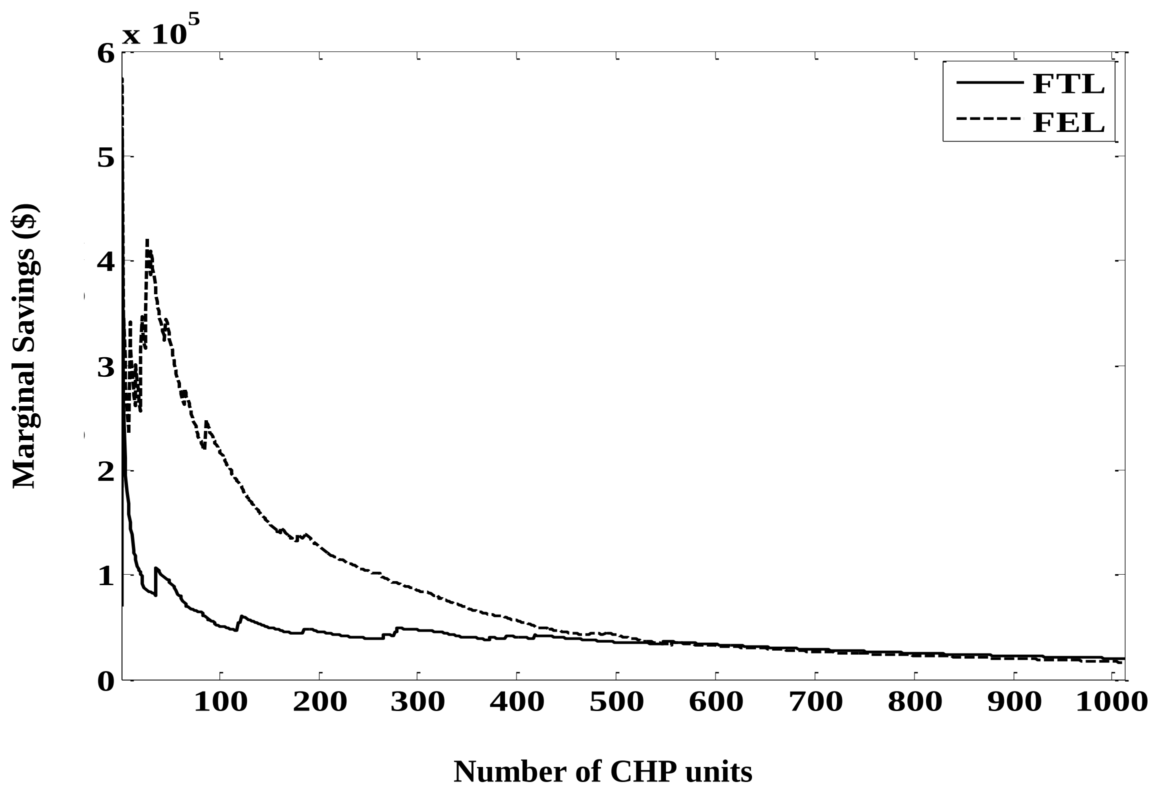

Figure 6.13 - Marginal savings with a $2/mmBtu natural gas price

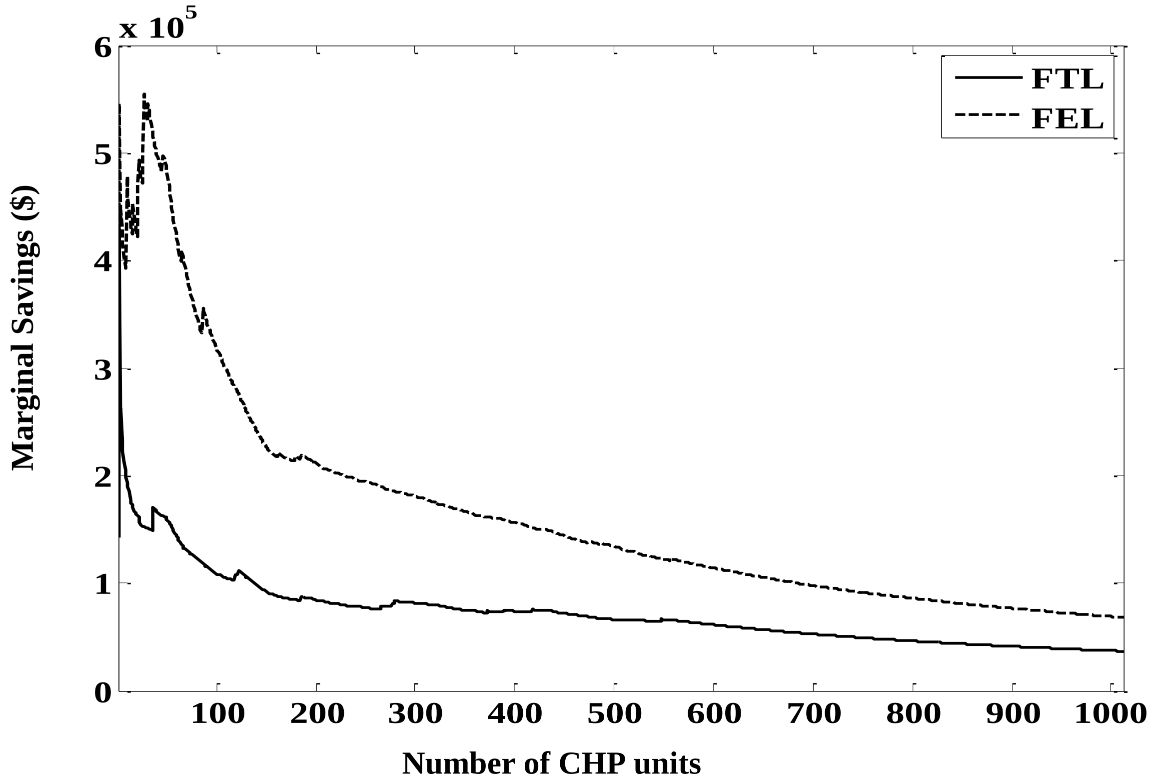

Figure 6.14 - Marginal savings with a $4/mmBtu natural gas price

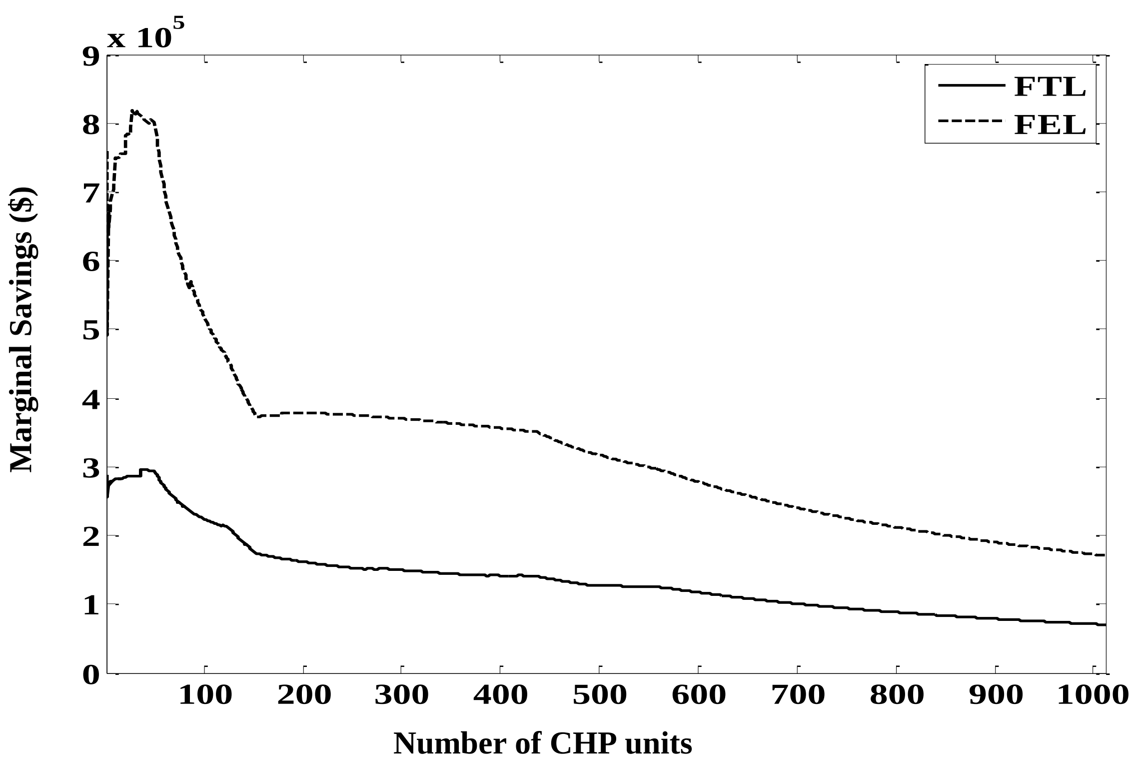

Figure 6.15 - Marginal savings with a $8/mmBtu natural gas price

For all levels of the natural gas price, there are fluctuations in the incremental savings from aditional CHP installations. This effect appears most prominent under the FEL mode of operation. The reason for this behavior is related to the mixture of coal and natural gas on the margin in the PECO zone of PJM (which is referred to as the "fuzzy gap" in section 3), especially in those scenarios with low gas prices. The supply curve model in section 2 was estimated with a natural gas price of \$7/mmBtu, a coal price of \$2/mmBtu and an oil price of \$10.66/mmBtu. With these fuel prices, the partial supply curves associated with coal, gas, oil and the threshold level is well-defined. With low natural gas prices, the cost of generating electricty from gas is as cheap as generating electricty from coal with a low natural gas price (say \$2/mmBtu). The threshold between the coal portion of the supply curve and the natural-gas portion of the supply curve becomes less well-defined. The fuel at the margin keeps switching between coal and natural gas leading to fluctuations in electricty prices. The savings from CHP is a function of the zonal elctricty price and hence there are fluctuations in incremental savings. Also, the deviations are minimal when the natural gas price is \$8/mmBtu which suggests that the supply curve model works better for higher natural gas prices. The fluctuations are minimal with CHP-FTL as compared to CHP-FEL because the demand reduction is not high enough to create siginificant flucutuations in electricty prices.

The net present value modeled as a function of electricty prices is estimated using equation (4), assuming a 10-year decision horizon and a 8 percent annual discount rate. Figures 6.16, 6.17 and 6.18 show how the marginal NPV for CHP installations changes with the three price scenarios. While some fluctuations can be observed in the NPV of an incremental CHP installation at low levels of CHP utilization, there is a general decline in the NPV of the marginal

CHP unit, as anticipated. Not only does marginal NPV decreases with incremental CHP installations and under certain operational and fuel-price scenarios, the equilibrium level of economical CHP deployment is substantially lower than the technical potential. With a \$2/mmBtu natural gas price the operating costs of a CHP unit is less but at the same time the savings is also less because of lower electricty costs. With a \$8/mmBtu natural gas price, the high operating costs is offset by the higher savings from avoided electricty prices.

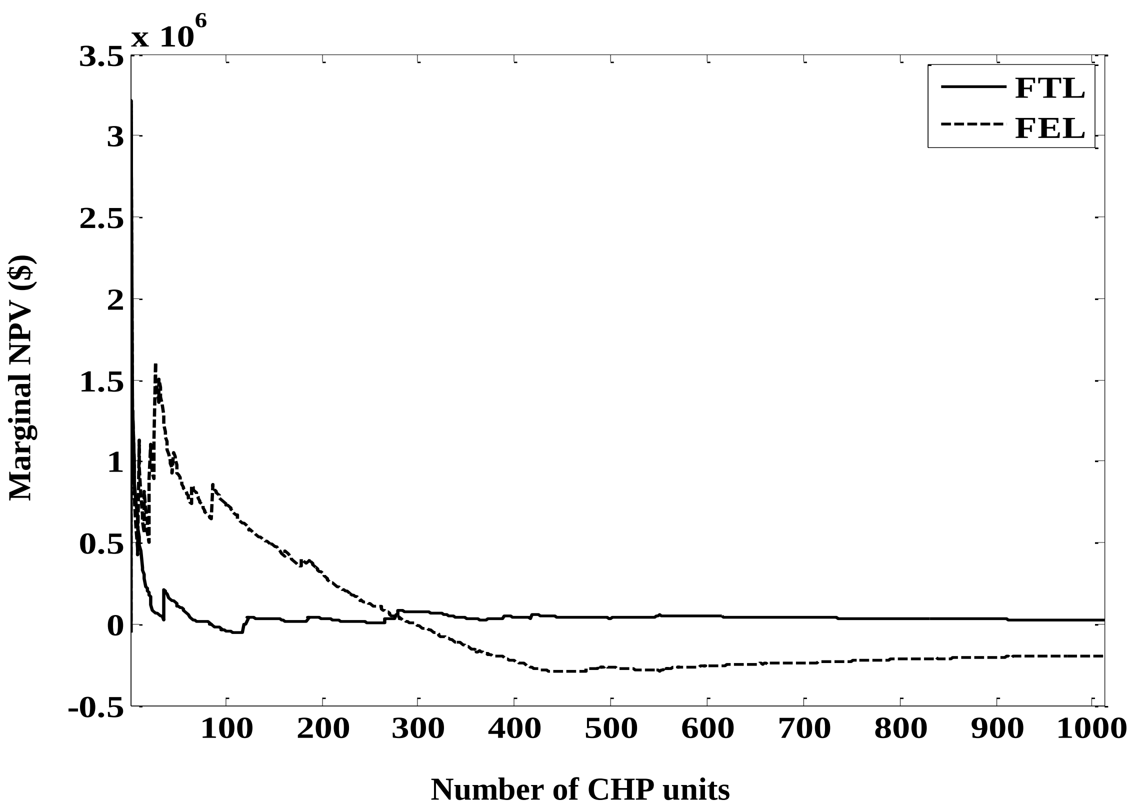

Figure 6.16 - Marginal NPV with a \$2/mmBtu natural gas price

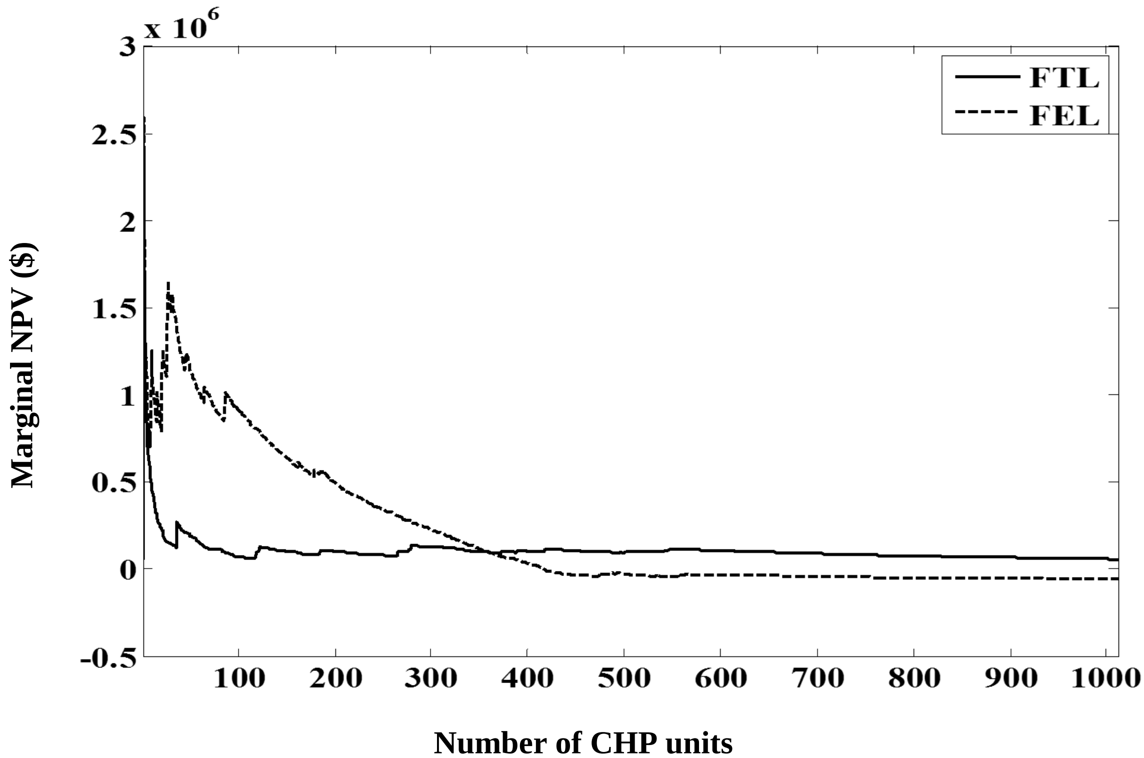

Figure 6.17- Marginal NPV with a $4/mmBtu natural gas price

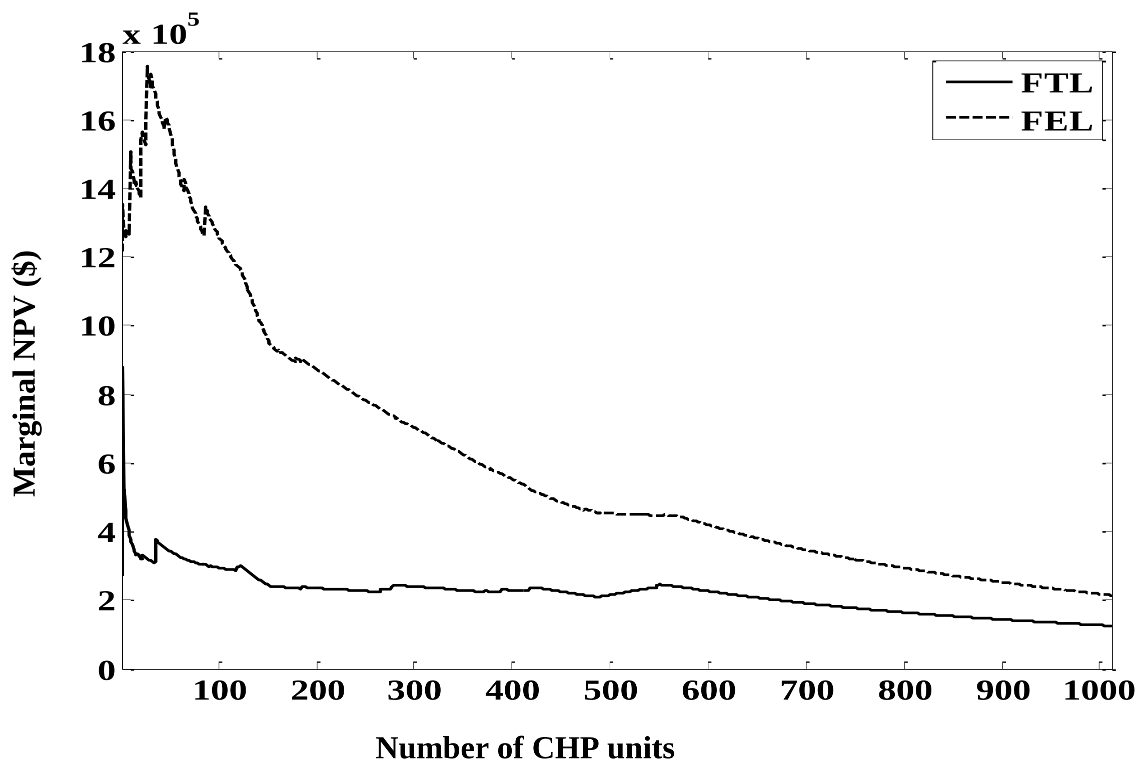

Figure 6.18 - Marginal NPV with a $8/mmBtu natural gas price

For the natural gas price scenarios of \$2/mmBtu and \$4/mmBtu the marginal NPV declines quickly under the FTL operational strategy, approaching zero by the time 100 to 150 CHP units (hotels) are installed and operating. The slope flattens after 150 CHP units are installed. This shows that savings under \$2/mmBtu and \$4/mmBtu natural gas price scenarios is not sufficient to offset the operational and capital costs for hotels. But as more CHP-FTL units are installed (in restaurants and office buildings), savings are adequate to offset the costs preventing the marignal NPV from dipping below zero (figure 6.16 and 6.17). The marginal NPV doesn't cross zero with a \$8/mm Btu for CHP-FTL. Hence, at low natural gas prices, the economic potential for CHP-FTL is about one-tenth of technical potential. In the case of CHP-FEL, for a gas price of \$2/ mm Btu the marginal NPV beomes zero after 298 units are installed; for a gas price of \$4/ mm Btu the marginal NPV becomes zero after 417 CHP units are installed. These points suggests that any further CHP deployment will not be beneifical. The marginal NPV doesn't cross zero with a \$8/mm Btu for CHP-FEL. Therefore, if all CHP units are operated according to FEL, the economic potential is larger (around three to four times as large as under FTL operations) but still substantially smaller than the technical potential in the lower gas price scenarios.

We draw three policy-relevant lessons from our analysis of CHP deployment in the Philadelphia region. First, higher gas prices in and of themselves do not economically disadvantage CHP – the spark spread (difference between gas and electricity prices) is the more relevant variable, as also pointed out by King and Morgan (2005). Our model of electricity pricing in Philadelphia and the operational costs of single-user CHP suggests that increases in natural gas prices will disproportionally affect electricity prices relative to CHP operational costs. Second, the operational strategy adopted for CHP matters just as much in determining profitable deployment levels as does the fuel price. Perhaps driven by high peak-time prices for electricity in Philadelphia, an operational strategy of electric load following (FEL) yields larger economic savings than thermal load following (FTL) when CHP has relatively low levels of adoption. At higher levels of adoption, FTL may be a more economical operational strategy when fuel prices are low (see Figures 7, 10 and 13). Third, except in the highest fuel-price scenarios, the economic potential for CHP in the Philadelphia region is substantially smaller than the technical potential. This conclusion suggests that additional policy measures to support CHP adoption (including the feed-in tariff policy option suggested by Siler-Evans et al, 2012) would need to be justified by further analysis of the social benefits of CHP in reducing greenhouse-gas emissions; improving local air quality; or improving the resiliency of electrical networks.

Chapter 7

Conclusions

CHP is a proven near-term solution to increase energy efficiency and reduce GHG emissions. The Philadelphia region has significant technical potential for CHP and with the recent development of Marcellus Shale, CHP could represent a substantial consumer of regionally produced natural gas. While previous analyses have modeled the individual decision to adopt CHP based on electricity market prices and other relevant variables, our analysis utilizes a statistical model of electricity supply and pricing in the Philadelphia region is used to capture relevant feedbacks between adoption rates, electricity pricing and the economic viability of incremental CHP adoption. Marginal savings and marginal NPV curves were estimated for three gas price scenarios and two CHP operation strategies (i.e., CHP-FTL and CHP-FEL). The marginal savings and marginal NPV decrease as the number of CHP units increase for all three-gas price scenarios and two CHP operation strategies. This study suggests that the priority rankings for CHP deployment are important considering a large-scale adoption of CHP in a region. The results suggests that higher natural gas prices and hence higher electricity prices, is favorable for CHP adoption. Under a range of operational assumptions and fuel prices, substantial CHP deployment could be achieved without reducing returns to the point where existing and incremental CHP installations would become uneconomic. The results of this study leads to a number of policy related questions such as how the natural gas demand created by a large-scale deployment of CHP might affect regional natural gas prices, assessing the importance of CHP as a source of reliable power, the associated environmental benefits, and factors affecting individual decisions to install CHP.

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Appendix A: Marginal Cost estimates for short run marginal cost curve

Table A.1 - Marginal costs for non-fossil fuel generators

Fuel type	Marginal Cost ($/MWh)
Wind	5
Hydro	10
Nuclear	15
Biomass	50

Table A.2 – Fossil-fuel Prices

Fuel type	Fuel price ($/million Btu)
Coal	2.41
Gas	5.01
Oil	11.76

A.3 Formula for calculating Marginal cost for fossil fuel technologies:

Marginal cost = Heat Rate(mliion Btu) * Fuel price($/million Btu)

Appendix B: PJM Interconnection Queue

TABLE B.1 Proposed gas fired capacity additions in Mid-Atlantic region – Under Study

Queue Number	Project Name	MW	MWC	MWE	In-Service Date	State	Transmission Owner
R11	South River	440	440	440	2013 Q2	NJ	JCPL
S107	Mickleton 230kV	580	580	580	2011 Q2	NJ	AEC
T107	Essex 230kV	625	625	625	2012 Q1	NJ	PSEG
T43	Essex 230kV	178	178	178	2012 Q2	NJ	PSEG
T45	Hudson 230kV	205	205	205	2011 Q2	NJ	PSEG
U2-074	Peach Bottom-Rock Springs 500kV	650	650	650	2012 Q4	PA	PECO
V3-017	Morgantown-Oak Grove	725	725	725	2012 Q2	MD	PEPCO
V4-020	North Temple 230kV	650	650	650	2014 Q2	PA	ME
W1-108	Grays Ferry 230kV	163	13	13	2011 Q2	PA	PECO
W2-023	Sewaren 230kV	625	625	625	2014 Q2	NJ	PSEG
W3-155	Alabama 13.8kV	1	0	1	2014 Q1	DC	PEPCO
W3-174	Churchtown 230kV 1	194	193.5	193.5	2015 Q2	NJ	AEC
W3-175	Churchtown 230kV 2	371	371	371	2015 Q2	NJ	AEC
W4-009	Raritan River 230kV	725	725	725	2015 Q2	NJ	JCPL
W4-015	Mickleton 230kV 1	210	136	210	2015 Q2	NJ	AEC
W4-016	Mickleton 230kV 2	340	340	340	2015 Q2	NJ	AEC
W4-021	Atlantic-South River 230kV	738	738.4	738.4	2015 Q2	NJ	JCPL
W4-023	Kearny 138kV	300	300	300	2014 Q2	NJ	PSEG
W4-024	Hudson 230kV	550	550	550	2014 Q2	NJ	PSEG
W4-044	Kelson Ridge 230kV	1450	725	725	2014 Q2	MD	PEPCO
X1-013	N. Lebanon 230kV	1110	1110	1110	2015 Q2	PA	ME
X1-039	Eagle Point 230kV	190	22.9	22.9	2011 Q2	NJ	PSEG
X1-068	Red Oak 230kV	776	10	10	2011 Q2	NJ	JCPL
X1-074	Hay Road 230kV	291	291	291	2015 Q2	DE	DPL
X1-108	Bangor	584	33	33	2012 Q4	PA	PPL
X1-109	E. Towanda 230kV	905	765	905	2015 Q1	PA	PENELEC
X2-011	Fairlawn 138kV	73	6	6	2012 Q2	NJ	PSEG
X2-012	Clinton 230kV	905	770	905	2015 Q1	PA	PPL
X2-025	Sunbury 230kV	416	416	416	2015 Q4	PA	PPL
X2-050	Essex 230kV	750	750	750	2015 Q2	NJ	PSEG
X2-066	S. Harrington-N.	312	309	312	2016 Q2	DE	DPL

	Seaford 138kV						
X2-067	Cartanza 230kV	309	309	309	2016 Q2	DE	DPL
X3-003	Mehoopany II 115 kV	64	0	20	2013 Q1	PA	PENELEC
X3-004	Essex 230kV	660	35	35	2015 Q4	NJ	PSEG
X3-006	North Temple 230kV	800	110	150	2014 Q2	PA	ME
X3-014	South Harrington-North Seaford 138kV	300	300	300	2016 Q2	DE	DPL
X3-029	Belvidere	11	0	11.15	2012 Q4	NJ	JCPL
X3-052	Essex 26.4kV	3	0	3	2011 Q4	NJ	PSEG
X3-068	Graceton 230kV	678	678	678	2015 Q2	PA	BGE
X3-070	Reybold 138kV	72	2	2	2011 Q4	DE	DPL
X3-078	Harrisburg 12kV	4	3	4	2014 Q3	PA	PPL
X3-081	Upper Darby 13kV	1	0	0.5	2012 Q2	PA	PECO
X3-087	Burches Hill-Brandywine 230kV	914	744	914.2	2016 Q2	MD	PEPCO
X3-088	Dickerson 230kV	440	440	440	2016 Q4	MD	PEPCO
X3-089	Sayreville 230kV	744	744	744	2016 Q4	NJ	JCPL
X3-102	Burches Hill-Possum Point 500kV	971	937	971.2	2016 Q2	MD	PEPCO
X4-005	Raritan River 230kV	785	60	60	2015 Q2	NJ	JCPL
X4-006	Kelson Ridge 230kV	785	0	60	2015 Q2	MD	PEPCO
X4-007	Kelson Ridge 230kV	785	0	60	2015 Q2	MD	PEPCO
X4-016	Bayonne 138kV	168	10	10	2013 Q3	NJ	PSEG
X4-018	Hudson 230kV	660	110	110	2015 Q2	NJ	PSEG
X4-019	Sunbury 230kV	227	227	227	2015 Q4	PA	PSEG
X4-020	Peach Bottom-TMI #1 500kV I	800	760	800	2016 Q2	PA	PPL
X4-021	Peach Bottom-TMI #2 500kV II	800	760	800	2016 Q2	PA	PPL
X4-026	Aquasco 230kV	792	650	792	2015 Q2	MD	PEPCO
X4-027	Linwood 230kV	852	35	12	2016 Q4	PA	PECO
X4-035	Burches Hill-Chalk Point 500kV	736	735.5	735.5	2016 Q2	MD	Pepco
X4-044	Aldene 230kV	27	27	27	2012 Q3	NJ	PSEG
X4-046	E Street (Sub 18) 13kV	16	0	16.1	2014 Q3	DC	PEPCO
X4-048	Lackawanna	1000	1000	1000	2017 Q2	PA	PPL
Y1-001	BL England 138kV	452	447	452	2015 Q2	NJ	AEC
Y1-011	Sewaren 230kV	520	520	520	2016 Q2	NJ	PSEG
Y1-025	Raritan River 230kV	785	725	785	2015 Q2	NJ	JCPL
Y1-026	Tosco 230kV	178	178	178	2012 Q1	NJ	PSEG

Table B.2 Proposed gas fired capacity additions in Mid-Atlantic region – Under Construction

Queue Number	Project Name	MW	MWC	MWE	In Service Date	State	Transmission Owner
Q90	Mickleton 230kV	650	650	650	2014 Q2	NJ	AEC
S121	Vineland 69kV	63	63	63	2012 Q2	NJ	AEC
S32	Perryman	256	230	256	2014 Q2	MD	BGE
S61	Tosco 230kV	180	20	20	2011 Q4	NJ	PSEG
T41	Kearny 138kV	178	178	178	2012 Q3	NJ	PSEG
T42	Kearny 138kV	89	89	89	2012 Q3	NJ	PSEG
V3-037	Naval Academy Junction 13kV	3	3.2	3.2	2013 Q2	MD	BGE
V4-019	Bergen 230kV	1259	60	60	2013 Q2	NJ	PSEG
W1-039	Pedricktown 230kV	120	10	10	2011 Q2	NJ	AEC
W1-062	Clayton 138kV	101	53	53	2012 Q2	DE	DPL
W4-010	White Oak	53	0	29.1	2015 Q4	MD	PEPCO

Table B.3 Proposed gas fired capacity additions in PECO – Active projects

Queue Number	Project Name	MW	Status	In Service Date	Transmission Owner	County
U2-074	Peach Bottom-Rock Springs 500kV	650	ACTIVE	2012 Q4	PECO	Lancaster
W1-108	Grays Ferry 230kV	163	ACTIVE	2011 Q2	PECO	Philadelphia
X3-081	Upper Darby 13kV	1	ACTIVE	2012 Q2	PECO	Delaware
X4-027	Linwood 230kV	852	ACTIVE	2016 Q4	PECO	Delaware

Appendix C: Mid-Atlantic region natural gas consumption and projections

Table C.1 Mid-Atlantic region natural gas consumption for electricity generation

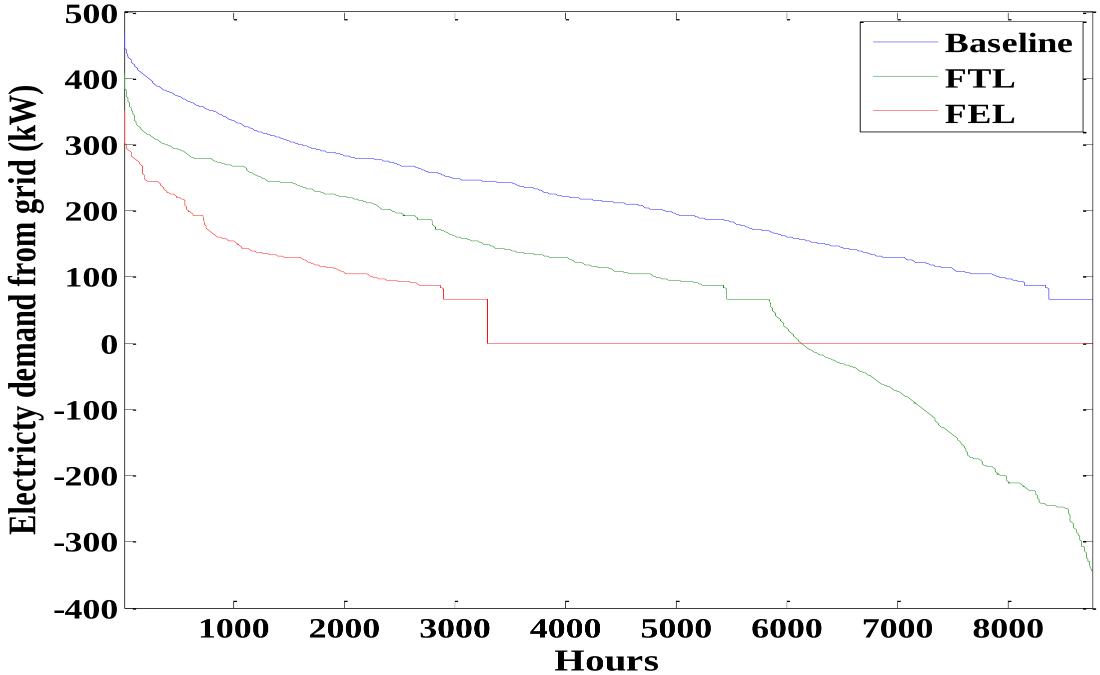
Year	Delaware	Maryland	New Jersey	Pennsylvania	Virginia	West Virginia	Total Mid-Atlantic
1997	16092	15524	134807	20430	19038	569	206460
1998	11135	21515	134563	30240	37808	515	235776
1999	19879	22842	140935	31353	41230	499	256738
2000	8371	28926	135350	20597	36700	516	230460
2001	15129	17520	128378	22632	33118	2620	219397
2002	17460	22273	160363	50251	34936	1885	287168
2003	11712	10995	130131	41238	35256	2084	231416
2004	13067	12045	140664	76186	48784	1406	292152
2005	12875	20478	125098	80640	66951	2287	308329
2006	9522	21830	130664	100946	60321	3664	326947
2007	13493	23079	157375	143954	90573	3849	432323
2008	11181	19910	169853	141011	76983	1889	420827
2009	10990	18039	164088	210542	94829	1109	499597
2010	24337	31327	196355	243236	139599	1480	636334

Table C.2 Mid-Atlantic region natural gas consumption projections for electric sector

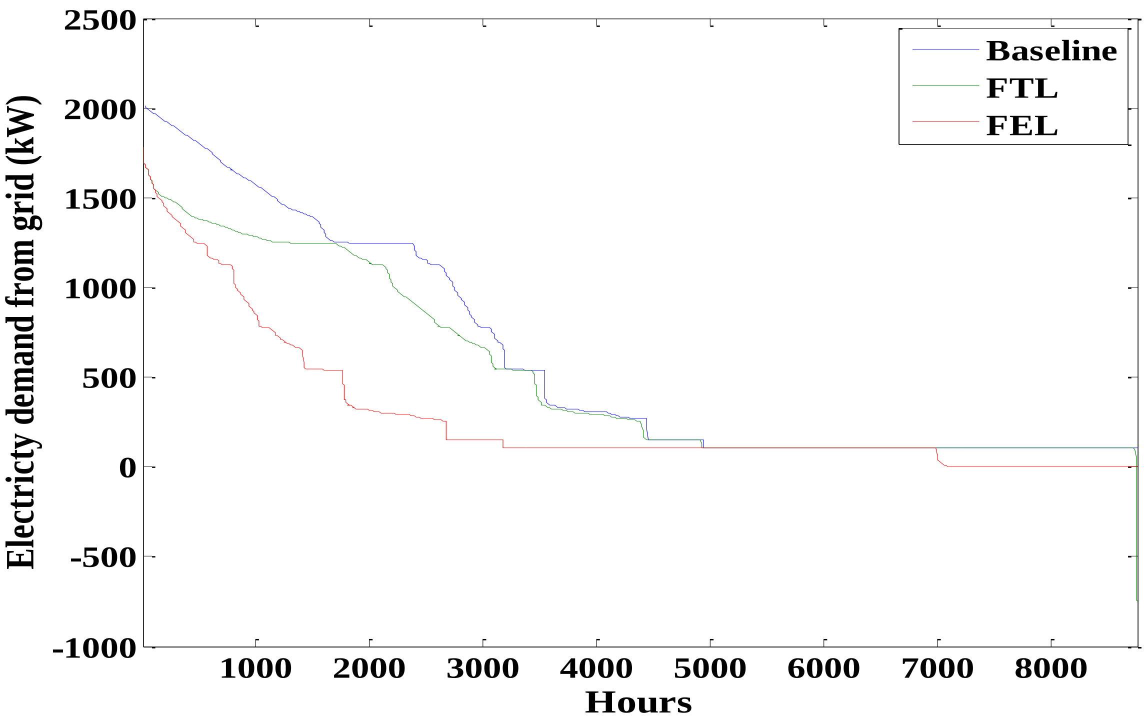
Year	Delaware	Maryland	New Jersey	Pennsylvania	Virginia	West Virginia	Total Mid-Atlantic
2011	24410	31421	197729	244939	140018	1484	640001
2012	24483	31515	199114	246653	140438	1489	643692
2013	24557	31610	200507	248380	140859	1493	647406
2014	24630	31705	201911	250118	141282	1498	651144
2015	24704	31800	203324	251869	141706	1502	654906
2016	24778	31895	204748	253632	142131	1507	658691

Appendix D: Load Duration Curves from BCHP screening tool

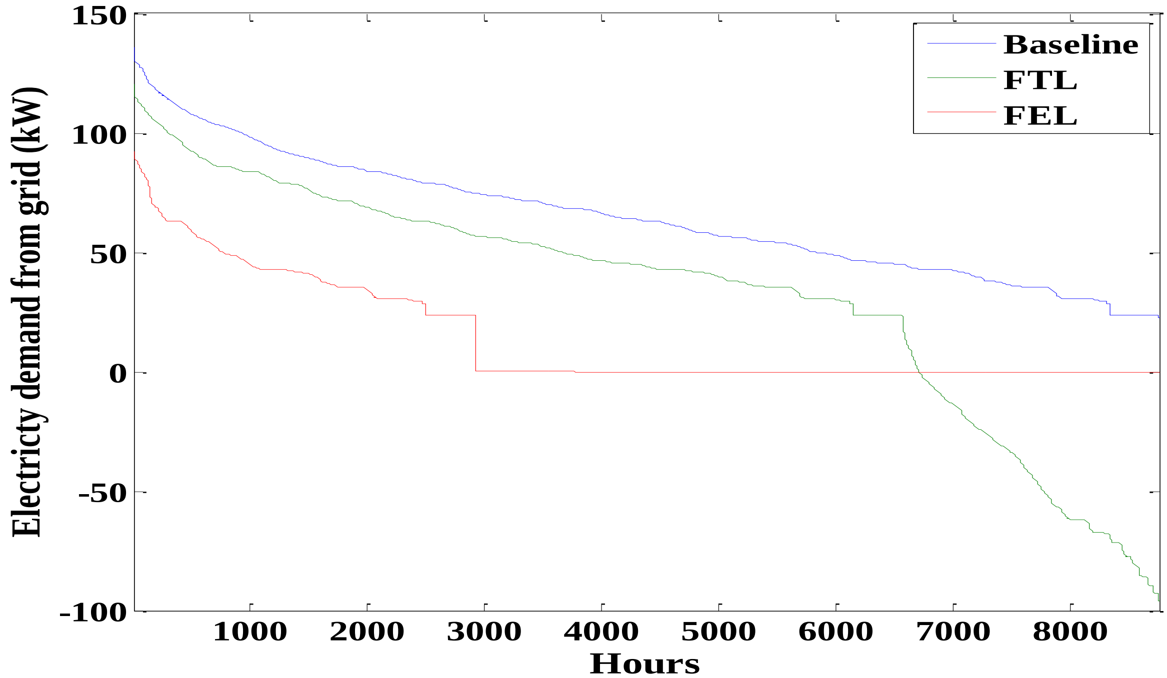
D.1 Large Hotel



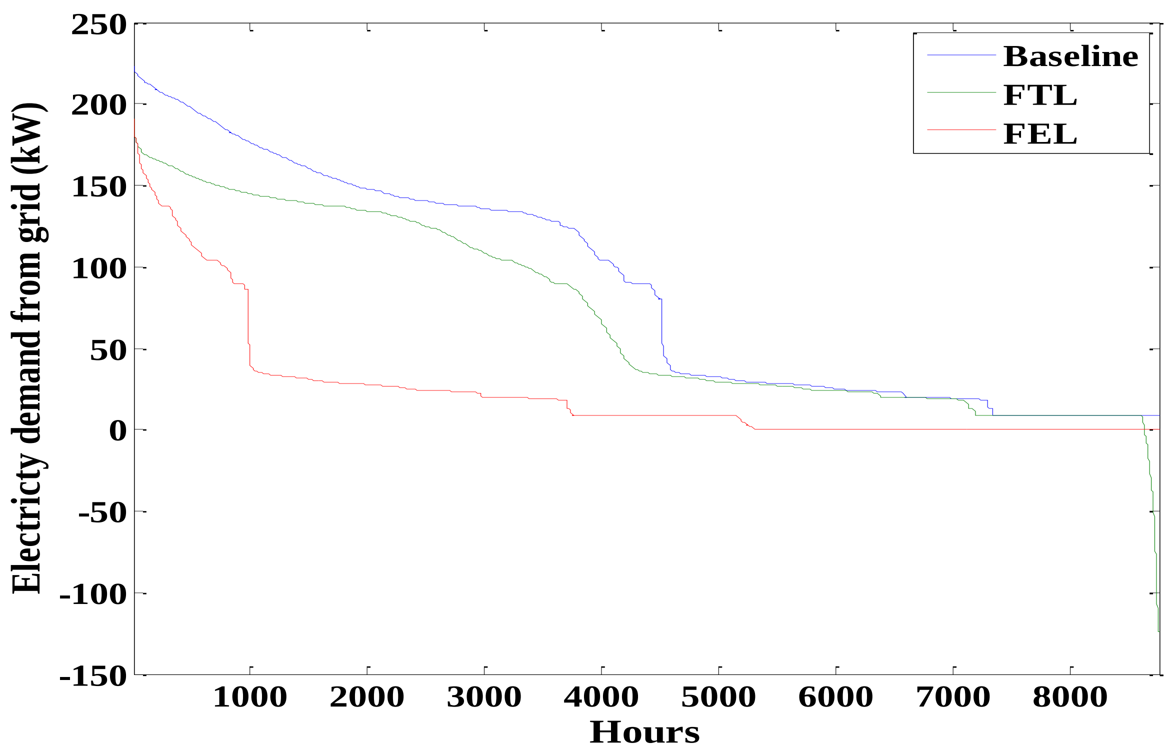
D.2 Large Office



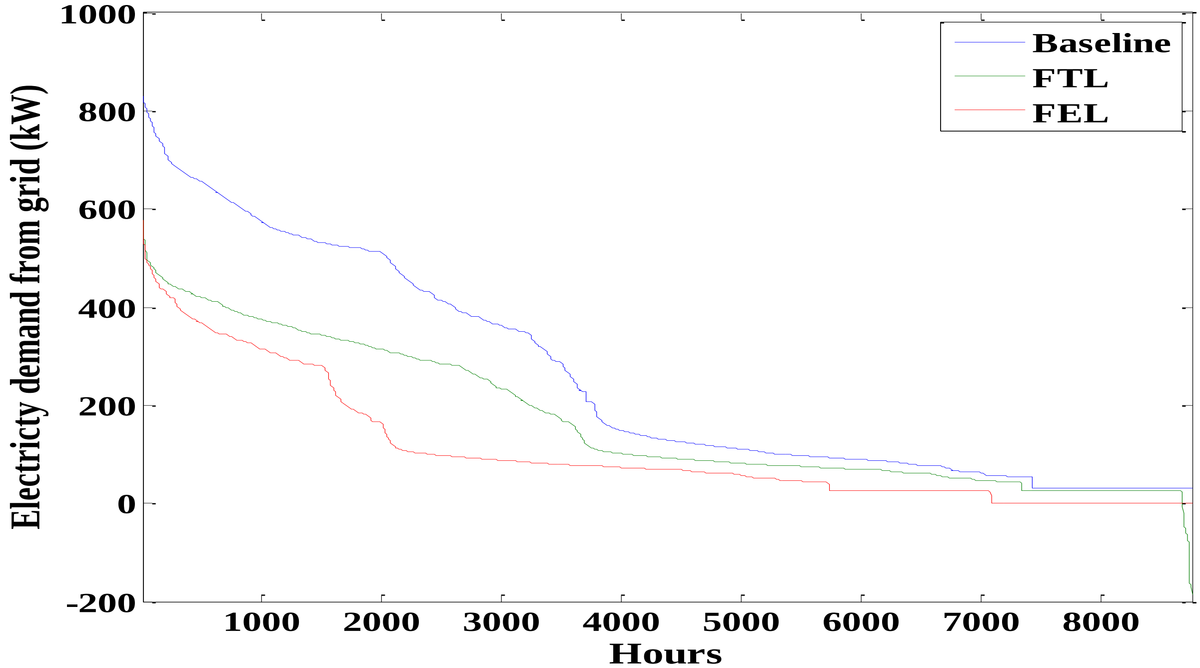
D.3 Motel



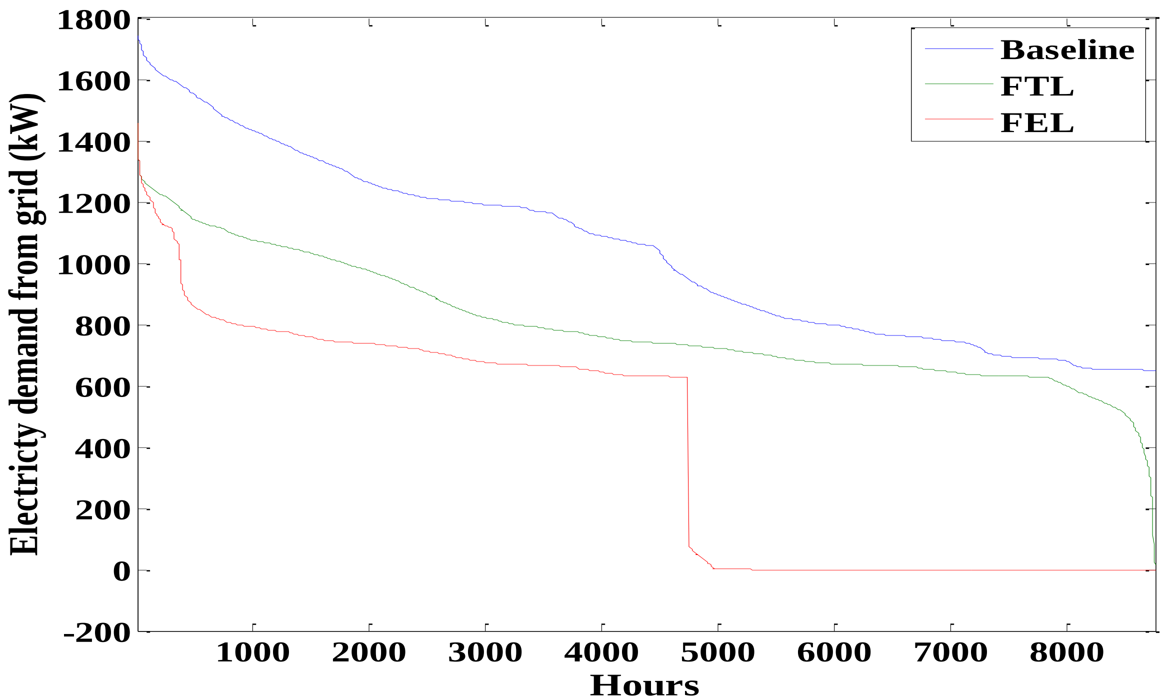
D.4 Supermarket



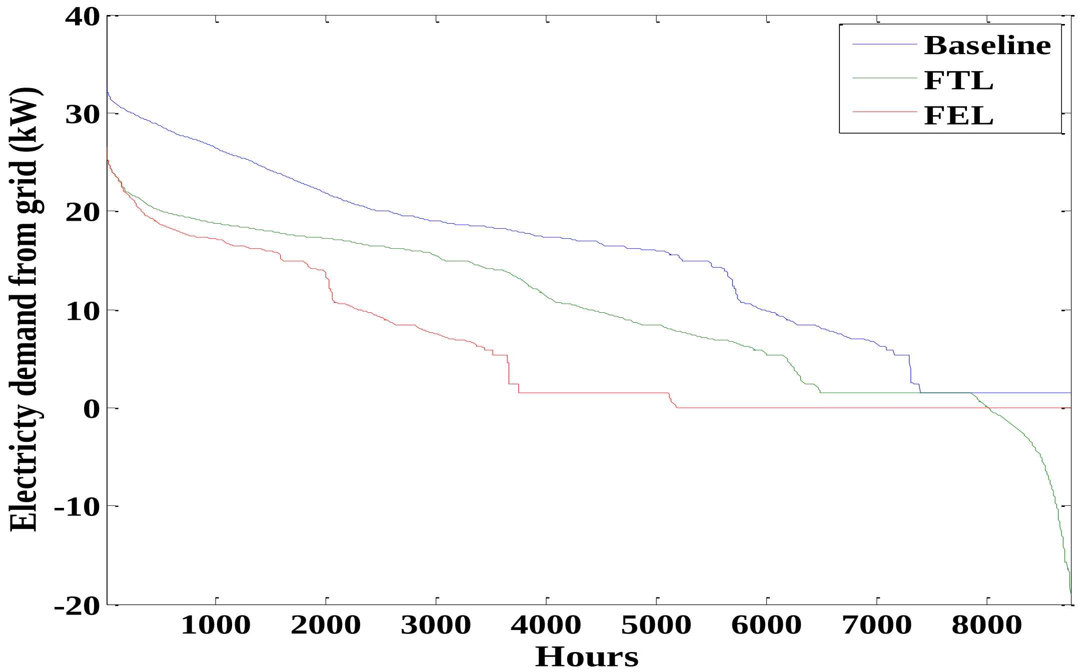
D.5 School



D.6 Refrigerated Warehouse



D.7 Restaurant



D.8 Hospital