Understanding the Impact of Large-Scale Penetration of Micro Combined Heat & Power Technologies within Energy Systems

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Abstract

Significant energy challenges today come from security of supply and environmental concerns. Those surpass the quest for economic efficiency that has been the primary objective until recent times. In an intensive fossil-fuel energy world, it is critical to find more effective ways of using the existing resources and of identifying technologies that can improve the sustainability of the energy model. Both, distributed energy resources and renewable-based electricity generation technologies are considered, by energy experts and also policymakers, to be essential for this purpose. Co-generation of electricity and heat at the residential level, known as micro-CHP, is an attractive alternative because of the potential for enhancing energy efficiency, reducing GHG emissions, and improving the utilization of primary energy resources.

This thesis aims at quantitatively assessing the impacts of a large-scale penetration of micro-CHPs within an energy system. Based on system-wide and residential metrics, this work intends to understand whether or not this technology is a valuable contribution to social welfare. For this purpose, a methodology is developed to integrate increasing numbers of micro-CHPs into a system's generation capacity expansion process over a 20-year timeframe, and into an electric power system's daily operation for a single year.

Findings from our long-term analysis demonstrated that micro-CHPs helped in reducing cumulative CO2 emissions. Under high-to-medium carbon price scenarios, they mostly displaced installed capacity from gas-based technologies, such as natural gas combined cycle units. Other results suggest that a larger micro-CHP penetration could be encouraged through economic incentives such as capital costs reduction, and/or lower natural gas retail prices, where conditions may favor one micro-CHP technology over another. Better economic conditions stimulate the deployment of micro-CHPs with low heat-to-power ratio (HPR), while machines with very high HPR do not appear to be a competitive alternative when compared to other micro-CHP technologies and conventional heating systems.

Findings from our short-term analysis demonstrated that widespread deployment of micro-CHPs results in positive effects, such as CO2 emissions reductions, energy efficiency improvements, decrease in system energy production costs, and summer peak load reduction at both system and residential levels. It was also found that these benefits could increase with the incorporation of additional features such as a hot water storage unit integrated with the heating system, micro-CHP modulating capability, and a micro-CHP price-based control strategy. However, the benefits at the system level seem to be relatively low for the level of penetration, assumed to be 10% of the total electric installed capacity. Moreover, the operation of a large number of these units considerably increases on-site natural gas fuel consumption all year round.

Results also suggest that an adequate tariff design improves the economic efficiency of the system and the operation of micro-CHPs under an intelligent control strategy. When the price signal sent to customers reflects the system's short-term marginal price, the operation of the micro-CHPs is more efficient, and with minimum excess heat. Moreover, findings show that a production subsidy in the form of a buy-back rate impacts the operation of micro-CHPs which may distort the short-term marginal price signal. Depending on the tariff rate, micro-CHPs may favor electricity-only production, resulting in increased costs, increased excess heat, and decreased efficiency. In addition, it was shown that a flat electric tariff rate may result in similar results as with an hourly retail rate, in particular for micro-CHP technologies with medium to high heat-to-power ratio.

In the end, the goal of this research is to have a better understanding of the conditions that influence the penetration of micro-CHPs, the economic signals that impact their operation, and the complexities that a widespread penetration brings to energy systems. We observe that this technology lends itself to qualitatively different ways of providing electricity service at value as seen by the customers. Future research is needed to explore potential of micro-CHPs for including customer choice.

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To Ari, Mati, and Luqui

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¡Los adoro infinitamente!

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CHAPTER 1

INTRODUCTION

1.1. Research motivation

Energy challenges today come mostly from security of supply and environmental concerns, surpassing the quest for economic efficiency that has been the primary objective until recent times. Under an intensive fossil-fuel energy world, it is critical to find more effective ways of using the existing resources and to identify technologies that can improve the sustainability of the energy model. Both, distributed energy resources and renewable-based electricity generation technologies are considered by energy experts, and also policymakers, to be essential for this purpose. In the particular case of distributed generation (DG), its connection to distribution or customer facilities could alleviate transmission and distribution network constraints, lower network energy losses, and improve system's reliability. The vast literature on the topic mentions a variety of other benefits such as CO2 emissions reductions, energy efficiency improvements, energy costs reductions, and even capital investments reduction in the distribution and transmission systems.

When considering that in the US around 65% of all energy used to generate electricity is lost during the electromechanical conversion process and across the transmission & distribution networks (1), the potential for efficiency improvements is very attractive for DG especially when configured as combined heat and power (CHP) applications. The production of co-generation electricity and heat improves the total net efficiency of the facility, reducing CO2 emissions, and potentially lowering energy costs. However, the possible benefits from CHPs depend not only on the technical challenges, but also on the regulatory framework and market conditions being in place. For example, benefits derived from CHPs will increase or decrease depending on the availability & suitability of the technology to precisely meet the customer's energy needs; the market conditions such as fuel, electricity and CO2 prices and CHP capital cost; and the regulatory framework, such as investment or production subsidies being in place.

This thesis aims at quantitatively assessing the value of CHPs not only to customers, but also to the overall energy system, with the purpose of understanding whether micro-CHP technology is a valuable contribution to social welfare. Working on the particular case of micro-CHPs at the residential level, this thesis develops a methodology that focuses on integrating a large number of micro-CHPs into the electric system's generation capacity expansion process, and integrating the daily operation of electric power plants with a significant volume of micro-CHPs on the customer's side. The developed methodology is used to assess the contribution of a large-scale penetration of micro-CHPs towards improving the use of energy in terms of efficiency, CO2 emissions, peak load reductions, and energy costs. This thesis makes use of traditional cost-based tools used in electric power systems, such as unit commitment and generation capacity expansion models. However, the novelty lies on explicitly including energy demand in the form of electricity and heat, incorporating large amounts of micro-CHPs able to simultaneously produce on-site electricity and heat, and looking at the system's optimal decisions while reacting to varied energy price signals.

Finally, this research aims at informing policymakers and regulators on the contributions of micro-CHPs as one more helpful measure in a carbon constrained world. It is expected also to better understand the conditions that influence the penetration of micro-CHPs, the economic signals that impact their operation, and the complexities that a widespread penetration brings to energy systems.

1.1.1. Development of micro-CHPs

Current energy policies are focusing on limiting greenhouse gas emissions, promoting renewable energy resources and energy efficiency improvements (2). As a result of these initiatives, the production of electricity from renewable and distributed energy resources is growing, and their contribution is expected to increase in the future as they are considered attractive alternatives in response to the above mentioned goals, especially mitigation of climate change (3). In 2005, the penetration of DG in 15 European member states showed that ten countries had a share above 10% over the total electricity capacity, where half of them had a share over 20% (4).

End-use energy efficiency improvement has been recognized as one of the most cost-effective approaches for improving the utilization of primary energy sources and reducing emissions in the short and medium terms (5). In fact, the co-generation of electricity and heat has been considered to be a relevant energy efficiency measure (2). Particularly, small cogeneration systems such as micro-CHPs are being supported by many governments, especially in Northern Europe. Micro-CHPs are seen as an alternative for residential heating systems with the additional capability of producing electricity, therefore increasing the overall energy efficiency of the system. The market potential – see (6), (7) - of this technology varies according to each country, depending on their energy consumption patterns, climate characteristics, natural gas availability, among other factors. Some studies mention that its penetration could be important by 2050 (7).

Finally, it is expected that technology improvements and mass production, the recognition of their environmental benefits, and government support will help to reduce costs and potentially increase the penetration of micro-CHPs in the medium term at residential level.

1.1.2. Impacts of micro-CHPs

An increasing penetration of distributed energy resources presents several challenges to the physical infrastructure, the economic operation and planning, and the institutional and regulatory subsystems within the energy system. Frequently, the literature cites several potential benefits from DG such as, economic savings, GHG emissions reductions, investments deferral in network infrastructure, provision of high quality power, energy losses reductions and local voltage support, and increased power supply reliability (refer for example to (8), (9), (10) (11), (12),(13) (14)(15)).

However, several concerns are also mentioned. Technical issues such as voltage regulation, system fault protection, system losses and distribution interconnection upgrades (15) (16), as well as the suitability of the different micro-CHP technologies for the diverse residential energy profiles, the inherent characteristics of these technologies, in-house heating system configuration, and local micro-CHP control modes(17). Within the economic uncertainties, it is mentioned the costs for electricity suppliers and distribution system operators; micro-CHP investment and operation costs; retail and feed-in electricity tariffs; competing heating technologies within the domestic sector; information and communication infrastructure costs; among others.

For the particular case of micro-CHPs, their effects when deployed in small numbers have been extensively studied. Authors have found that micro-CHPs bring economic savings and emissions reductions to residential customers when compared to the traditional model of producing heat and purchasing electricity from the utility company. It has been shown that these savings vary depending on the technology being in place, as well as the householder energy profile, energy prices, and potential economic compensation for excess of electricity sold back to the grid ((17), (7), (18)).

Regarding the effects of micro-CHPs when deployed at large scale, some studies focus on the impact on distribution network costs, technical effects within a particular distribution network, and the potential micro-CHP contribution to reliability, for example ((19) (20), (21) (22)). However, there is a lack of studies exploring the long-term planning and short-term operational effects of having an important volume of micro-CHPs within energy systems that simultaneously consider heat and electricity. It is important to understand capacity displacement of conventional electric power technologies as the penetration of micro-CHP increases, and the operational patterns in the system as energy is produced closer to the load centers.

1.2. Research questions

This thesis focuses on assessing the value of micro-CHP technologies from the energy system regulator's point of view. When micro-CHPs are analyzed from the customer-only perspective, it is clear what the costs, efficiency and environmental benefits are. However, when this technology is analyzed in a broader context - particularly under a large deployment - the benefits need to include the overall impact within the energy system and they may be less apparent.

The main questions that this thesis tries to answer:

- What are the impacts of micro-CHPs in an energy system if their penetration is large? In particular:
    - What the long-term effects are on installed capacity of conventional electric power technologies and cumulative CO2 emissions, under investment cost, carbon price, and retail fuel price uncertainty?
    - What the short-term effects are in terms of energy efficiency, CO2 emissions, peak load reductions, natural gas consumption, and energy costs over a single year?
- What are the main economic signals that affect the level of penetration and operational pattern of micro-CHPs?

More specifically, this research explores the evolution of an electrical system that is continuously adapting to an increasing number of micro-CHPs. For that, this work has to look at the installed electricity generation capacity being displaced by the introduction of micro-CHPs. In addition, this thesis looks at the short-term effects in an energy system that is optimally adapted to its energy demand and integrated with the operation of many micro-CHPs.

From the system regulator's viewpoint, this thesis analyzes the electricity production costs in a particular energy system, and the energy costs that consumers incur when operating micro-CHPs at the residential level. Also, it looks at the cumulative CO2 emissions for the time horizon, and emissions and energy efficiency for one particular year of analysis paying attention to seasonal variations. In addition, an examination of the technologies being displaced by the penetration of micro-CHPs is done, and the effects on electricity production by the operation of a high number of micro-CHPs. For example, it is explored electricity peak reductions during summer months, on-site natural gas consumption, and the operational patterns of micro-CHPs subjected to more accurate electricity retail prices.

Critical in this thesis is the assumption that micro-CHPs have the capability to react to economic signals sent to end-customers. In the model, the economic operation of micro-CHPs is integrated with the economic operation of an electric power system through hourly electricity prices, allowing micro-CHPs to operate according to the signals given by the electricity market. The inclusion of this feature allows a better understanding of the operation of micro-CHPs in response to electricity retail prices. For example, variations to the short-term effects are examined for flat and time differentiated rates, as well as for a pricing structure that incorporates additional charges on top of the short-term electricity marginal prices.

1.3. Research methodology

The thesis develops a methodology that focuses on integrating a large number of micro-CHPs into the electric system's generation capacity expansion process and, integrating the daily operation of electric power plants with a significant volume of micro-CHPs on the customer's side. As mentioned, the purpose is to understand the value of an increasing number of micro-CHPs to residential users and the energy system they are embedded in.

This research uses traditional optimization techniques normally used to understand the economic operation of electric power systems in the short and long terms, and a cost-based optimization to model the operation of micro-CHPs at the residential level. In particular:

- For the economic operation of micro-CHPs at the household level, an optimization model that incorporated heat storage is used to get their least-cost operation, and an energy simulator to represent the electric and thermal loads of varied residential customers.
- For the integration of micro-CHPs into an electric power system, a daily unit-commitment model is used to schedule the operation of the electric power units, and a generation capacity expansion model to get the incremental installed capacity in the system with increasing numbers of micro-CHPs.

For the first part, the operation of the micro-CHP is based on economic signals and energy load conditions. It is assumed that the householder optimizes his short-term profits over one year, on a daily basis. Depending on how sophisticated the information and communication systems are, the micro-CHP owner may have information regarding the market conditions and base his operational decision on that. For the least-cost criterion case, the users operates their machines when it is more cost-effective turning the micro-CHP on rather than buying electric power and fuel separately for meeting his energy demands. The profits are defined in terms of the variable operational costs from operating the micro-CHP and auxiliary heating units, and possible income from selling back excess of electricity to the grid.

For the second part, the generation capacity expansion problem is formulated as an optimization problem, where some centralized decision-maker minimizes the total costs of producing electricity over a time horizon of 20 years. The costs include not only the annual operational costs, but also the investment costs for generation capacity expansion necessary to cover demand and long-term reserve requirements. Then, based on the energy portfolio derived from the long-term decision process for the last year of the study time, the methodology focuses on integrating the operation of a large number of micro-CHPs with the operation of conventional electric power plants in the short-term. For this purpose, this thesis combines the unit-commitment problem used for scheduling the operation of the electric power system, with the micro-CHP economic operation at the residential level. Electricity prices are passed to final customers who decide the least-cost operation of their micro-CHPs, and an iterative process is done with the purpose of determining the system's final short-term marginal prices.

Finally, by including micro-CHP's response to energy prices, the model provides the chance to better understand the value of micro-CHPs under different retail pricing schemes, and more generally the economic effects of having more transparent information on the consumer's side.

1.4. Thesis outline

The next chapter provides a literature review on distributed generation, micro-CHP technologies and development, micro-CHP adoption status in several countries, and a discussion of previous studies that examine the impacts of micro-CHPs. Chapter 3 develops the micro-CHP household model, presents the mathematical formulations for varied control strategies, and provides preliminary results for two cases in terms of energy costs, energy efficiency and emissions. Chapter 4 performs sensitivity analyses to features such as heat storage tank size, micro-CHP heat-to-power ratio, and retail electricity price. Chapter 5 describes the formulation of the long-term generation expansion planning model, and develops the methodology that integrates the price-based operation of a large number of micro-CHPs with the unit-commitment of electric power units. Chapter 6 presents the results for the long-term analysis under investment cost, carbon price, and retail fuel price uncertainty; and the results for the short-term analysis for one particular year in terms of costs, CO2 emissions, energy efficiency and peak demand at system and residential levels. Chapter 7 summarizes the findings of this thesis, discuses their regulatory implications, and proposes areas of future research.

CHAPTER 2

LITERATURE REVIEW

Environment, energy security and diversification, and sustainability are usually perceived as the main challenges an energy policy should deal with. In particular, current energy policies are focusing on limiting green house gases emissions, promoting renewable energy resources and energy efficiency improvements (2). As a result of these initiatives, the production of electricity from renewable and distributed energy resources (DERs) is growing, and their contribution is expected to grow in the future as they are considered attractive alternatives in response to the above mentioned goals, especially climate change (3).

End-use energy efficiency improvement has been recognized as one of the most cost-effective approaches for improving the utilization of primary energy sources and reducing emissions in the short and medium term[1] (5). One way of achieving efficiency gains is by means of combined heat and power, or cogeneration of electricity and heat, which is considered to be a relevant energy efficiency measure (2). In particular, small cogeneration systems such as micro-CHPs are being supported by many governments (especially in Northern Europe). Although the current economics of small scale electric generation is expensive, it is expected that future technology improvement and mass production, efficiency gains through the recovery of waste heat, and potential environmental benefits will help to reduce costs.

In this chapter, we first describe DER, and then we focus on cogeneration systems for residential applications. We explain the main technologies used for residential CHPs, as well as their current status in the market. We describe how this technology is developing in the US and other European countries, in addition to the latest regulatory support. Finally, we explain the main results of previous work dealing with the economic and regulatory impact of micro-CHPs.

2.1. Distributed Energy Resources

Distributed energy resources (DERs) include demand-side and supply-side resources deployed within the distribution system or the customer side of the meter. DERs include not only fossil fuel-based technologies (reciprocating engines, fuel cells, combustion and steam turbines), but also renewable technologies (photovoltaic systems and wind turbines), and combined heat and power systems (CHP). In

[1] When compared to increasing energy supply to satisfy energy demand.

addition, according to Ackermann et al. (23), DERs include not only distributed generation, but also distributed energy storage and demand-side resources, such as load management systems (i.e. electricity is moved from peak to off-peak periods) and energy efficiency options (i.e. peak or overall electricity demand is reduced, energy efficiency is increased).

For the particular case of distributed power generation (DG), the authors in (23) define DGs considering a range of characteristics:

- DGs are able to provide a source of active electric power.
- DGs are connected directly to the distribution network or to the network on the customer side of the meter. Hence, the rating of the DG source will depend on the capacity of the distribution system, and the authors suggest categories of DGs:
    - Micro DG: ~1W < 5kW,
    - Small DG: 5kW < 5MW,
    - Medium DG: 5MW < 50MW, and
    - Large DG: 50MW < ~300MW.

2.1.1. Combined heat and power

For the specific case of Cogeneration, also known as Combined Heat & Power production (CHP), the term is defined as "the process of producing both electricity and usable thermal energy (heat and/or cooling) at high efficiency and near the point of use". It is noted in (6) that there are three key elements in this definition:

- Simultaneous production of electricity and heat.
- A performance criterion based on high energy efficiency.
- A locational criterion based on the proximity of the energy conversion unit to a customer.

CHPs capture and use the waste heat from the thermal power generation process, increasing the energy conversion efficiency of the process (close to 80% or more) as the recovered heat is used for heating and/or cooling purposes. Since they are located at or near the point of use, CHPs reduce in addition the losses in the transmission and distribution system if the energy is used to supply local on-site needs (See Figure 2.1.1).

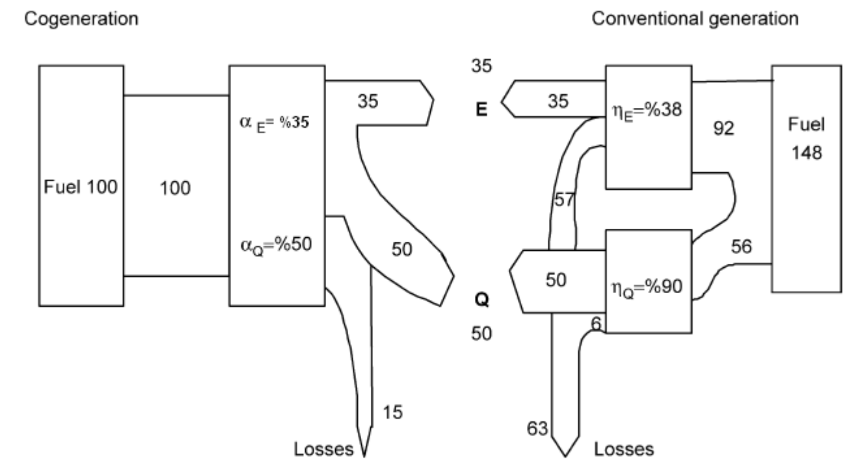

Fig. 1. Cogeneration versus conventional generation [4], where α_E, part of the energy transformed into electricity in a cogeneration unit, α_Q, part of the energy transformed into usable in a cogeneration unit, η_E, electrical yield of an electrical power plant (production of electricity only), η_Q, yield of a boiler (production of heat only), E, electricity demand, Q, heat demand. **Source: Onovwiona & Ugursal**

Figure 2.1.1: Cogeneration process vs. Conventional generation

As shown in Figure 2.1.2, in CHP systems the power is produced by a prime mover technology. This is a device that converts fuel or heat energy into mechanical energy which is used to run generators or motors. The heat produced is a by-product of the process and, instead of being wasted in the conversion process, is captured and used for other thermal applications. Normally, a heat recovery system is used for capturing and using the waste heat, providing for additional thermal energy that is used for other processes.

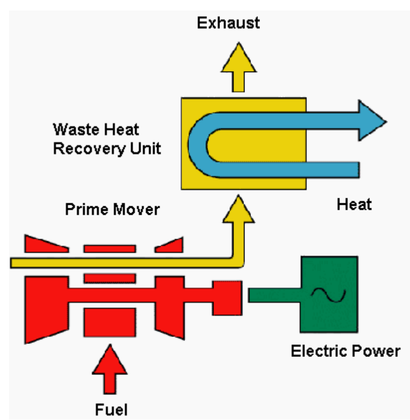

Figure 2.1.2: CHP basic operation

CHP systems can be applied to a series of applications ranging from hot water, steam, chilled water, space heating, to electricity. Conventional applications may include small units that serve apartment buildings, health clubs to large units serving industrial and manufacturing facilities, refineries, hospitals, military facilities, hotels, universities, and other industrial, institutional or commercial applications (24). As with MIT Cogeneration plant (9), the facilities can produce part of their electrical and thermal needs, while still purchasing that portion of the electricity from the utilities to balance out their loads. Also, they can export electricity to the grid during periods when they generate more power than their needs, although this requires a more sophisticated engineering design of the facility and interconnection infrastructure, as well as resolution of regulatory and legal issues.

As mentioned in (25), depending on the "*magnitude of the electrical and thermal loads, whether they match or not, and the operating strategy*", the cogeneration system may need to run at part-load conditions, the surplus energy (electricity or heat) may need to be stored or sold, and energy deficiencies may need to be purchased from other sources such as the electrical grid (or a boiler plant). The surplus heat may be stored in a thermal storage device, while surplus electricity may be stored in electrical storage devices such as batteries or capacitors. Unlike wind and solar generating technologies, CHP systems can operate continuously and can be controlled by their owners.

Although cogeneration is mostly used in large industrial, commercial, institutional facilities and district energy systems, applications at residential level (i.e. single-family <10kWe and multi-family 10-30kWe) are currently being developed and deployed. This application is known as micro-CHP, which according to (6) it is defined as "the simultaneous generation of heat, or cooling, energy and power in an individual building, based on small energy conversion units below 15 kWe",[2] where the produced electricity can be used within the building or fed into the electric grid.

Micro-CHPs are being considered as alternative devices for replacing conventional boilers/furnaces, with the additional feature of generating electricity. Usually, a size limit is adopted to restrict the use of these systems in single-family dwellings, apartment houses, small business enterprises and hotel, different from district heating systems for example. Finally, as noted in (25), due to the non-coincidence of thermal and electrical loads in single-family applications, an electrical and/or thermal storage or connection to the electrical grid may be required.

2.2. Micro-CHP technology description

Co-generation technology and in particular micro-CHPs combine various components such as a prime mover[3]-generator set, a supplementary thermal system, a balance of plant including heat exchangers, and a control system and/or power electronics. As mentioned in (7) most systems are designed to be alternatives to a home-heating system, and as such will be required to provide similar comfort levels, similar installation space requirements and costs as such systems. In particular, reciprocating engines, combustion turbines, steam turbines, micro-turbines and fuel cells are the prime mover technologies considered suitable for residential applications.

2.2.1. Energy conversion technologies

Conversion technologies such as reciprocating engines, Stirling engines, gas turbines and steam engines base their process on combustion that produced heat, which later is converted into mechanical energy that drives a generator set to produce electricity. Different from this category are fuel fells which base their process on electrochemical conversion from the chemical energy stored in the fuel into electrical energy. However, some of these technologies have not been yet developed for micro-CHP applications, such as micro gas turbines which usually have electrical capacities above 25kWe (6).

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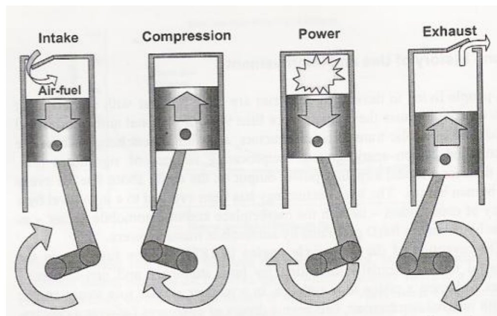
[2] This definition includes a size relatively large for applications targeted to residential customers, as previously noted in (23).

[3] Device that produces the mechanical energy mostly used to drive an electric generator.

a. Reciprocating internal combustion engines.

Based on piston-driven internal combustion engines, micro-CHP applications use Spark Ignition (Otto-cycle) engines. Otto-cycle consists of four strokes (see Figure 2.2.1 (26) for an illustration), where the "intake" stroke takes air mixed with fuel into the cylinder, then the "compression" stroke compresses the cylinder content where combustion takes place producing pressure and heat to move the piston in the "power" stroke, and finally in the "exhaust" stroke the exhaust of the combustion process is removed from the engine (26). Spark ignition engines are mostly run on natural gas, although they can be set up to run on propane, gasoline or landfill gas (25).



Source: Willis and Scott

Figure 2.2.1: Otto cycle used in internal combustion engines

As the piston moves, the crankshaft rotates. This mechanical energy is used to drive a generator. The exhaust heat as well as the heat from the lubricating air cooler and he jacket water cooler of the engine are recovered using heat exchangers, and then supplied to the heating system. As seen in Figure 2.2.2 (6), capital cost of reciprocating engines decreases as the electrical capacity of the system increases, and electrical efficiency increases as the capacity increases.

According to (25), some of the advantages of internal combustion CHPs over other technologies are low capital cost, reliable onsite energy, low operating cost, ease of maintenance, and wide service infrastructure[4]. Although not all of the heat produced by an internal combustion engine can be captured for on-site electric generation, by recovering it from the cooling system and exhaust process between 80% and 90% of the energy from fuel is used.

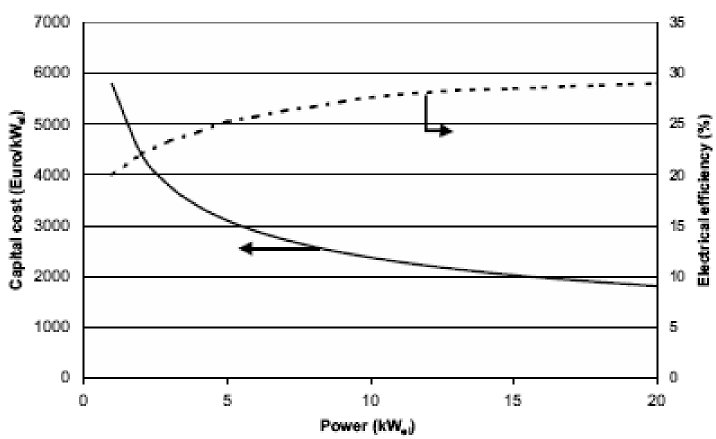


Figure 2.2.2: Capital cost & electrical efficiency for reciprocating engines

[4] This technology was one of the first ones being commercialized for residential applications by Honda Motor Co. It has been in the market for about 10 years, and it has been deployed in Japan and Europe, and most recently in the U.S.

Finally, up to this date[5] several micro-CHPs based on reciprocating engines are commercially available for residential applications, as shown in Table 2.2-1 below. In general, the electrical output of the systems being offered is high, which is best suitable for large residential homes or small commercial applications. There are two technologies capable of modulating electric and heat load, which could be more appropriate for medium size dwellings. In addition, we note that the European market is more developed than the U.S. market, and engine manufacturers are partnering with domestic heating manufacturers to market the micro-CHP units as part of a residential heating system. The ICE micro-CHP system has been reasonably successful in Germany and Japan, where their location is usually outside dwellings or in the basement because of the relatively large size (7).

[5] As of April 2010.

Developer		Baxi-SenerTec (27)		Honda (28) (29)	Ecopower[6] (30) (31)		Yanmar (32) (33)			EC Power[7] (34)
Model / Technology		Dachs G5.5	Dachs G5.0	MCHP/Freewatt	ecoPower e4.7	ecoPower e3.0	CP5VB	ENER.G4Y	ENER.G10Y	XRGI 15G
Fuel[8]		Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas
Output:										
Electrical	[kWe]	5.5	5.0	1.2	1.3 - 4.7	1.3 - 3.0	5.0	3.87	10	6 - 15.2
Thermal	[kWth]	12.5 - 14.8	12.3 - 14.6	3.46	4.0 - 12.5	4.0 - 8.0	9.6	8.38	17.3	17 - 30.0
Efficiency:				>85	> 90	> 90	85	84.5	84.2	92
Electrical	[%]	27	26	22	25		29	26.7	30.7	27
Thermal	[%]	61 - 72	63 – 74	64	65		56	57.8	53.5	Up to 65
Service interval	[hr]	3,500	3,500	6,000	4,000		10,000	10,000	10,000	8,500
Service life		20 yr 80,000 hr	20 yr 80,000 hr		40,000hr					40,000 hr
Total installed	[unit]		Over 17,000	Over 80,000	Over 3,000					
Availability		- UK by Baxi-SenerTec UK - Germany & EU by SenerTec - Ireland by Kinviro		- Japan - US by ECR International - Germany by Vaillant	- US by Marathon Engine Systems - EU by Vaillant & PowerPlus Technologies	- Germany by Vaillant	- Japan	- EU by Ener.G		- Europe by EC Power

Table 2.2-1: Reciprocating engine-based micro-CHPs of size up to 15kWe

[6] Load modulating from 1.3kWe and 4kWth.
[7] Load modulating from 6kWe and 17kWth.
[8] Most of the technologies can use different type of fuels, such as natural gas, LPG, Propane. However, in this table we only include the technical characteristics for natural gas-fired micro-CHPs.

b. Stirling engines.

In these types of engines the combustion process takes place externally in a separate burner. As seen in Figure 2.2.3 (35), a piston moves a working gas between a high temperature chamber and a cooling chamber at low temperature. While the gas moves from the hot to the cold chamber, a regenerator captures the heat from the gas and then returns it to the gas as it moves back to the hot chamber (which enhances the thermal efficiency of the process). The mechanical energy of the engine is used to drive the generator (6) either through conventional mechanical elements (kinematic type) or through a linear alternator (free-piston type).

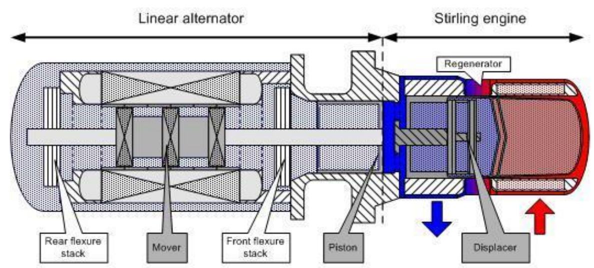


Figure 2.2.3: Free Piston Stirling Engine

The electrical efficiency of these engines is close to 20% in larger systems, while for smaller size is around 10 to 12% only. Total energy efficiency is usually above 90%. Unlike reciprocating engines, as the heat supply is from external sources, it is possible the use of a wide range of energy sources including fossil fuels such as oil or gas, and renewable energy sources like solar or biomass. In addition, Stirling engines have low wear and long maintenance intervals, and are quieter and smoother than reciprocating engines (25). Operating lifetime is expected to be over 10 years for this type of technologies.

As seen in Table 2.2-2, some Stirling engine micro-CHPs are being commercialized already while others are expected to enter the market in the next year or so. It is also shown that this technology is mostly being developed and commercialized in Europe through partnerships with utility companies and in-home heating manufacturers. Developments in the U.S. are limited to manufacturing the engine, which is used by companies in the Netherlands and Japan (36). Finally, we note that for small size micro-CHPs - about 1kWe - the electrical efficiency is very low, with very high heat-to-power ratio (about 6 to 1) which may be more suitable for high heat demands in the northern regions of Europe.

Developer	WhisperGen Limited[9] (37) (38) (39) (40) (41)	Baxi (42)	Remeha (43)	Enatec (35) (36)	Cleanenenergy (44)	Sunmachine[10] (45)	Disenco (46)	Stirling Systems (47)
Model / Technology	WhisperGen MkV	Baxi Ecogen	Based on Microgen engine	Based on Infinia engine	Cleanergy CHP V161	Sunmachine Pellet	HPP	SEM
Fuel	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas Biogas	Wood Pellets	Natural gas	
Output: Electrical [kWe] Thermal [kWth]	 1.0 7.0	 1.0 6.0	 1.0 6.0	 1.0	 2-9 8-26	 1.7 - 3.0 6.5 - 10.5	 3 12-18	 1.2 5
Efficiency: Electrical [%] Thermal [%]	>90 ~11 ~80	92	92	 10	92-96 25 67-71	>85 20 65	>90	>90 18
Service interval [hr]	Every year	Every year	Every year		4,000-6,000hr	Every year or 3,500hr	Every year	
Service life	Similar to boiler	Similar to boiler	Similar to boiler	25 yrs			15yrs	
Availability	- New Zealand by Whisper Tech - EU by Efficient Home Energy SL - Germany by Sanevo, DSE-Vertrieb - Belgium & Netherlands by The Magic Boiler - UK by E.ON, 2011 (estimated)	- UK by Baxi Group, 2010 (estimated)	- Germany & Netherland by Remeha	- EU by EnAtEc	- Sweden by CLEANERGY AB	- Germany by Sunmachine	- UK by Disenco, 2010 (estimated)	- Germany, Switzerland

Table 2.2-2: Stirling engine-based micro-CHPs of size up to 15kWe

[9] Information provided by Gary Whitfield from WhisperGen Limited & Technical manuals.
[10] Most technologies operate at one particular set-point. However, some manufacturers note the ability to modulate within an electrical output range.

c. Fuel cells.

Fuel cells use an electrochemical process that converts hydrogen-rich fuels into electricity and heat. This technology consumes oxygen obtained from air, and hydrogen contained in fossil fuels, such as natural gas, petroleum, liquefied petroleum gas (LPG), petroleum, methanol, or coal gas. Although fuel cells are considered emerging technologies, their good performance makes them attractive for cogeneration applications. However, their high costs and short life time need to be overcome to allow a larger penetration of this type of technology in the future (25).

In general, fuel cells have an anode, a cathode, and contain an electrolyte material that allows ions to pass, blocking the electrons (see Figure 2.2.4). A hydrogen reformer extracts hydrogen from the hydrocarbon fuel such as natural gas, and then it is pumped through a cleaner and filter into the fuel cell. The hydrogen flows to the anode where the pulled off electrons, that cannot pass through the electrolyte membrane to the cathode, travel around it in an external circuit to generate DC power. At the cathode, the hydrogen is oxidized when the electrons combine with the hydrogen ions and oxygen to form water or steam. The exhaust heat is steam that can be used for cogeneration purposes using a heat recovery system. Finally, since the oxidation of hydrogen produces a charge that creates a direct current (DC) flow from the anode to the cathode, an inverter is required to convert the DC power into AC alternating current (26).

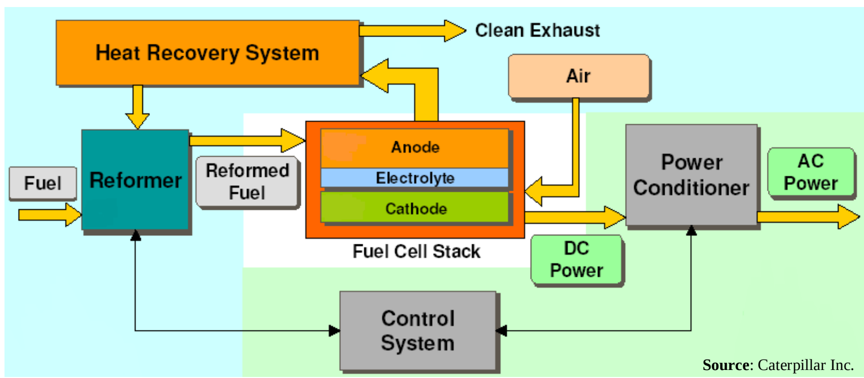


Figure 2.2.4: Fuel cell basic operation

To achieve higher capacities, a number of single fuel cells can be connected in series, which it is known as a fuel cell stack. As mentioned in (6), micro-CHPs based on fuel cells for small-scale applications are either based on Polymer Electrolyte Fuel Cells (PEFC)[11] or Solid Oxide Fuel Cells (SOFC), while natural gas is the fuel available for most micro-CHP applications:

- Low-temperature Polymer Electrolyte Fuel Cells (PEFCs) use a thin membrane as an electrolyte and operate at about 80° C. At low capacity range PEFCs may reach electrical efficiencies on the order of 28% to 33%, and they are projected to achieve up to 36% for domestic systems.

[11] Also known as Proton Exchange Membrane Fuel Cells (PEMFCs).

- High-temperature Solid Oxide Fuel Cells (SOFCs) work above 800°C and use ceramic as an electrolyte. Their high temperatures allow high efficiency levels above 50% for large size units[12]. For low-power range, the electrical efficiency may be around 45% or higher, but usually the efficiency is better than that in PEFCs.

Fuel cells are still under development and demonstration projects are currently being conducted to better estimate their performance. Overall efficiency of PEM and SO fuel cells is expected to be as high as 80% (25). In addition, FCs durability is an area of undergoing research, as the number of start/stop cycles and ramping rates impact their lifetime and performance degradation (7).

Finally, as seen in Table 2.2-3 and Table 2.2-4, most developments targeting residential applications are being done in Europe. Japan is closely collaborating with utility gas companies to introduce fuel cells into the market in the near future. Field tests are currently being conducted across Europe and in some parts of the U.S., with expected commercialization dates for 2011/2012. In particular, we see that SOFCs are actively being developed and tested by companies, which are already working on commercialization agreements with utility and heating technology companies. PEMFCs are still under development with field tests for up to 2 more years[13,14]. Finally, we note that some FCs manufacturers are adding modulation capability within a specific electric power output range.

[12] The high quality waste heat can be used for powering, for example, a steam turbine in a combined cycle system above 25MVA, and it can also be used for large-scale cogeneration applications (26).
[13] The government of Japan has promoted trials for this technology, where companies such as Toyota Motor Company, AISIN, and other have collaborated.
[14] Other developers include RWE and Vaillant from Germany. However, as the technology is still under development technical information is scarce.

Developer	Hexis (48)	Ceramic Fuel Cells[15] (49)	Acumentrics (50)	Ceres Power (51)	Topsoe (52)
Model / Technology	Galileo 1000 N SOFC	BlueGen SOFC (based on Gennex[16])	AHEAD SOFC	SOFC	PowerCore SOFC
Fuel	Natural gas	Natural gas	Natural gas / Propane	Natural gas	Natural gas
Output: Electrical [kWe] Thermal [kWth]	1.0 2.5	0.5-2.0 0.4-1.0	1(nominal)-2.5(peak)	1.0	1.0
Efficiency: Electrical [%] Thermal [%]	>90 25-30 (target: >30)	60- 85 36-60 (max at 1.5kW)	>90 30(nominal)	HPR<0.7	85 45 40
Service interval		Every year (minor) >1 year (major)	Every year (minor) 9,000hr (mayor)		
Availability	- Under development - Field tests in Europe	- Under development & field trials - Agreements with utilities & appliance partners in Australia, Europe & Japan to deploy micro-CHPs	- Field test in the US	- Under development & field trials - Agreement with partners in UK and Ireland for annual volumes - Target start date for sale: 2011	- Under development - Field trial in Denmark

Table 2.2-3: SOFC-based micro-CHPs of size up to 15kWe

[15] The company claims that this technology has a power output modulation capability, within a 0.5 – 2.0 kWe range.
[16] Micro-CHP application based on Gennex Fuel Cell Module.

Developer	Ballard (53)	Baxi Innotech[17] (54)	Panasonic (55)	IRD[18] (56)	Dantherm Power (57)
Model / Technology	FCgen- 1030V3 PEM	Gamma 1.0 (based on FCgen- 1030V3)	PEM	IRD Gamma PEM	PEM
Fuel	Natural gas	Natural gas Biogas	Natural gas	Natural gas	Natural gas
Output: Electrical [kWe] Thermal [kWth]	1.2	1.0 (30%-100% modulation) 1.7	1.0 0.3-1.0	1.5 (0.9-2.0 range) 1.5 (0.8-2.0 range)	5
Efficiency: Electrical [%] Thermal [%]		85 32	38 55	~90 44	
Service interval [hr]	4,000				
Service life	40,000hr (target)				
Availability	- Supplies FCs to BAXI INNOTECH, developer of FC micro-CHPs in Europe	- Field test in Germany until 2012	- Field tests since 2005 in Japan - Unknown commercialization status	- Under development - Field trials in Denmark	- Demonstration in Denmark - Full market launch expected in 2012

Table 2.2-4: PEMFC-based micro-CHPs of size up to 15kWe

[17] The company claims that this technology has a power output modulation capability between 30% and 100% of its electrical capacity.
[18] The company claims that this technology can modulate within a 0.9-2.0kWe range.

Based on the above tables, the main characteristics of the different conversion technologies can be summarized as follows (Table 2.2-5):

Summary		**ICE**	**SE**	**FC**
Electrical size	[kWe]	1.2 - 15.2	1.0 - 9.0	1 – 2.5
Thermal size	[kWth]	3.4 - 30.0	6.0 - 26	1 – 5.0
Electric efficiency	[%]	22 - 31	10 - 25	25 - 60
Overall efficiency	[%]	85 - 90	90 - 96	60 - 90
Heat-to-Power ratio	[pu]	~ 2 - 3	~ 4 - 8	< 1 – 2.5
Maintenance interval	[hr]	Every year	Every year	Every year
Service life	[yr]	~ 10 - 20	~ 15 - 25	~ 10 (target)
Fuel		Natural gas, LPG, Propane	Natural gas, Propane, Wood Pellets	Natural gas, Propane, Biogas
Load modulating		Offered by some companies	Offered by some companies	Offered by some companies
Commercial availability		Sales in Europe, Japan, and the US	Sales in Europe	Development stage

Table 2.2-5: Micro-CHP technologies main characteristics

Finally, when comparing reciprocating engines (ICE), Stirling engines (SE), and fuel cells (FC) for *residential cogeneration applications* we see the following:

- Electrical efficiency is the highest for FCs. ICEs offer higher electrical efficiency than that of SEs.
- SE technology offers the highest overall energy efficiency, followed by ICEs, and FCs.
- Natural gas is the preferred fuel being used by all technologies.
- Installed costs and performance data are not readily available for all technologies, especially for the small-scale range. However, FCs are expected to be the most expensive, followed by SEs and ICEs.
- ICE micro-CHPs were the first technology to be commercialized, aimed mostly at large residential dwellings in Germany and small houses in Japan. At this time, SE is the main technology available for sale in Europe, while FC technologies are still under development.
- Europe and Japan have taken the lead in developing micro-CHPs for residential applications, while the U.S. is slowly entering the market with micro-CHPs based on ICEs.

CHP technologies in general are characterized by their heat-to power ratio (HPR), which is defined as:

$$HPR_{CHP} = \frac{Energy \quad produced \quad as \quad heat}{Energy \quad produced \quad as \quad electricity}$$

The HPR is useful for guiding which CHP technology to install in a facility. In general, longer running hours and better system efficiency are expected when the CHP's HPR is close to the consumer's energy ratio (58). Therefore, micro-CHP technologies with high HPR values may be more suitable for residential applications where the heat requirement is continuously much larger than the electric demand. From the manufacturers' information, it is noted that SEs have the greatest HPR, followed by ICEs and FCs respectively.

2.2.2. Supporting technologies

Before introducing micro-CHPs in large numbers, it is necessary to clarify issues related to building system integration, interconnection, reliability and safety. Besides the electrical modifications to integrate the micro-CHP system to the house's electrical system (i.e. additional wiring, meters, disconnect switches, fuses, electrical panels and others); auxiliary heating & storage devices may be required to allow an efficient use of residual heat; and measuring, communications and control systems may be needed to enhance the micro-CHP operation.

In (59) for example, it is looked at a research house used to assess a prototype micro-CHP unit that would provide electricity and heat, while exporting any surplus back to the grid. In this particular case, the existing integrated gas-fired space and water heating system (furnace and hot water heater) was connected to the micro-CHP and upgraded with thermal storage tank. The micro-CHP was the heating source to the storage, which was used for supplying domestic hot water and space heating. The existent burner was used as back-up or supplemental burner. Since the micro-CHP was configured in heat-driven mode, sensors were used to control its operation based on the temperature in the storage tank.

More general, the supporting technologies may be very different depending on the in-house heating system configurations and interconnection requirements for each type of customer. In the U.S. for example, warm-air heating configurations are predominant, while in Europe hot water-based configurations are the most popular:

- A micro-CHP warm-air heating system is based on the integration of an energy conversion technology with a high efficiency warm air furnace used for additional heat when demand for heat is high. The furnace heating capacity will vary depending on the characteristics of the residential building.
- A micro-CHP hot-water heating system, also known as hydronic system, uses a prime mover, a high efficiency boiler, and potentially a hot water tank (for domestic hot water) and a hot water storage tank. The boiler provides the additional heat requirements when demand is high, and the storage tank gives more flexibility to meet peak heat demand.

The storage tank acts as a buffer between the heat demand and the micro-CHP heat production. It allows a smoother operation of the micro-CHP at times when there is demand of heat, as the energy can be obtained from the storage unit instead of running the micro-CHP. In addition, any excess of heat can be stored at times when there is demand of electricity but not of heat. In addition to the thermal storage system, electric storage can also be used to enable a micro-CHP grid independent operation. However, up to this date, most micro-CHP applications are grid connected without additional backup. Any excess of electricity is injected back to the electric grid, and any deficit of electricity is withdrawn from the grid.

As the micro-CHP is connected to the electrical grid, it is expected that will play a more active role within the electrical system. Information, communication and control systems are required for an efficient operation. Particularly, web-based applications can monitor micro-CHP's operation[19], measure and collect operating data, send failure and maintenance alerts, receive external signals such as electricity rate. Depending on the networking level of the micro-CHPs, the more complex the more sophisticated the system is expected to be, such in the particular case of Virtual Power Plants (VPP), where several DGs are integrated and coordinated by means of an energy management system (6).

Finally, key to the future integration of micro-CHPs into electrical systems is their ability to sense and respond to various systems' signals, and communicate with the operator or utilities. Information-based technologies, such as smart metering, coupled with control systems and time-based pricing should help householders to manage their energy consumption and related costs. In particular, reading and responding to system's conditions, such as energy price signals and system load conditions, metering on-site production and consumption, and communicating with a system operator or utility should increase the potential value of micro-CHPs for the energy system and residential customers.

2.2.3. Micro-CHP operational strategies

Besides the technical specifications of each technology, it is also important the operational strategy that micro-CHPs may adopt to meet on-site energy loads. However, it is important to note that a flexible or part-load operation may impact the performance of the technology. Some of the control strategies normally mentioned in the literature (60), (21), (61) are:

a. Heat-led operation.

- Base load. Micro-CHP unit operates at constant thermal capacity and any excess electricity is injected back to the utility grid.
- Load following. Micro-CHP unit operates to meet thermal load subject to the maximum thermal capacity. Additional heat requirement is provided by the supplementary heating system. Excess electricity is injected back into the grid. As noted in (21), this is the most common control strategy being used by commercially available micro-CHPs.

b. Electricity-led operation.

- Base load. Micro-CHP unit operates at constant electric capacity and any excess of thermal energy is discarded into the atmosphere.
- Load following. Micro-CHP system operates to meet electric load subject to the maximum electric capacity. Excess of thermal energy may be discarded into the atmosphere.

[19] Internet connection for system monitoring is available for most micro-CHPs currently being offered in the market.

- Peak shaving. Micro-CHP system operates on periods of peak electric demand and any excess of thermal energy during those hours is discarded. This strategy may be desirable when electricity prices are high.

c. Least-cost operation. Micro-CHP system operates to meet both thermal and electrical loads while minimizing the aggregate energy cost of the residential customer. The operation is subject to technical constraints and takes into account energy prices and on-site energy requirements.

2.3. Micro-CHP development

As we mentioned earlier, micro-CHP is one of the many technologies being considered within the current energy and environmental policy discussions. Micro-CHPs are seen as an alternative for residential heating systems with the additional capability of producing electricity, increasing the overall energy efficiency of the system. The market potential – see (6), (7) - of this technology varies according to each country, depending on their energy consumption patterns, climate characteristics, natural gas availability, among other factors. Some studies mentioned in (7), have found that in the UK the market potential could be 5.6 million homes by 2020, while in Germany around 6 GWe of capacity could be in place by year 2050.

However, without government support only a small penetration of micro-CHP technology could be expected in the medium term. At this time, manufacturers are working on improving the performance of this technology, and lowering the costs to make it more accessible to residential customers. They are also working to create partnerships with dealers and heating manufacturing companies to launch the product to the market. Governments are working on ease the interconnection process to this type of technology, while offering economic support through grants or feed-in-tariffs.

2.3.1. Status in the US

As shown in Table 2.2-1, Table 2.2-2, and Table 2.2-3, the current development and deployment of micro-CHPs in the U.S. has been very low. Micro-CHPs are at their early stage, with internal combustion-based micro-CHPs being offered by a couple of companies located in the Northeast and Midwest regions - one company is targeting large households and small commercial buildings, while the other is aiming single-family dwellings. In addition to these companies, we also showed that there are other companies working on fuel cell-based micro-CHPs for residential applications, some of them partnering with European boiler manufactures to target the European market. However, fuel cells suitable for residential micro-CHP applications are still under development and field trials are in progress, with at least a couple of years from mass production. In the case of micro-CHPs based on Stirling engine, we could not find companies in the U.S working on this application.

In (25) is suggested that one of the reasons for this low growth trend rest on the characteristics of the heating systems in the U.S., which are mostly forced warm-air using natural gas-fired furnaces instead of boilers. The costs of furnaces is much lower than the cost of boilers, making the cost differential between a micro-CHP and a conventional heating supply higher in the U.S. case than in the European case. However, this cost differential could be lower for some regions, such as for example in the Northeast region where hot water-based systems are more common[20]. Other reasons for the low penetration of micro-CHPs include low electricity prices, varied interconnection requirements across utility companies, and the lack of policy support specifically targeted at developing micro-CHPs.

However, during the past years Net Metering has been one of the regulatory approaches being used in the U.S. to pay customers able to produce their own electricity. This particular program may help to stimulate a higher penetration of micro-CHPs within some regions of the country, together with a pricing scheme and interconnection process that support the development of this technology. Net metering program allows customers to compensate their own electricity usage, by reducing the electricity purchases from the utility company and, in case the customer has some surplus, to compensate them with a monetary credit. Physically, the meter spins backward when customers generate more electricity than they actually need, and the customer only pays for his net consumption at the end of the billing period.

In the particular case of Massachusetts[21], Net Metering program[22] is applied to certain eligible facilities up to 2MW of capacity (62). According to their size, three different classes of systems are defined - Class I, Class II and Class III[23] - being

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[20] According to (101) there are 111.1 million housing units, from which 5.5 million belong to the New England-Northeast census region. Of the total households, about 40% have natural gas-fired central warm-air furnace and 7% natural gas how water systems (fuel oil-fired systems are 3% and 4% respectively for each type of heating system). These national average numbers change drastically when considering the New England census division:

- Natural gas-fired systems account for 15% and 24% for warm-air furnace and hot water system respectively.
- Fuel oil-based systems account for 16% and 27% for warm-air furnace and hot water system respectively.

[21] Chapter 169 of the Acts of 2008 (the "Green Communities Act") in section 116 established the following energy state's goals (105):

- "Meet at least 25% of the commonwealth's electric load, including both capacity and energy, by the year 2020 with demand side resources including: energy efficiency, load management, demand response and generation that is located behind a customer's meter including a combined heat and power system with an annual efficiency of 60 per cent or greater with the goal of 80 per cent annual efficiency for combined heat and power systems by 2020;
- Meet at least 20% of the commonwealth's electric load by the year 2020 through new, renewable and alternative energy generation;
- Reduce the use of fossil fuel in buildings by 10% from 2007 levels by the year 2020 through the increased efficiency of both equipment and the building envelope;
- Develop a plan to reduce total energy consumption in the commonwealth by at least 10% by 2017 through the development and implementation of the green communities program...that utilizes renewable energy, demand reduction, conservation and energy efficiency."

[22] Net metering is established by Chapter 169 of the Acts of 2008 - the "Green Communities Act" –in section 78, and it is regulated by the Department of Public Utilities in Massachusetts. For more information refer to (62) and (103).

[23] Class I facilities are systems up to 60 kW in capacity. Class II facilities are systems greater than 60kW and up to 1MW in capacity that generate electricity from agricultural products, solar energy or wind energy. Class III facilities are systems greater than 1MW and up to 2MW in capacity that generate electricity from agricultural products, solar energy or wind energy.

Class I for systems up to 60kW of capacity[24] and the one of interest for us as it is applicable to micro-CHPs.

Customers[25] need to get interconnection approval from the local distribution company before generating any electricity. According to Section 18.03 of (63), special fees - such as backup charges and demand charges, or additional controls or liability insurance - do not apply to Class I Net Metering Facilities as long as the facility meets the interconnection standards and all relevant safety and power quality standards[26]. As specified in Section 18.04 of (64), distribution companies should calculate for each billing period the net metering credits for Class I – other than wind, solar, and agricultural - as the "product of*:*

- Excess kilowatt-hours, by time-of-use if applicable; and
- Average monthly clearing price at the ISO-NE."

For Class I solar and wind facilities, value of the Net Metering Credits at the end of a billing period is slightly less than the utility's full retail rate as they would receive credit for the default service, distribution, transmission, and transition charge. Specifically, as defined in 220 C.M.R.18.04 (31), credit for these facilities is equal to the "product of:

- Excess kilowatt-hours, by time-of-use if applicable; and
- Sum of the following Distribution Company charges applicable to the rate class under which the Host Customer takes service:
    - Default service kilowatt-hour charge (in the ISO-NE load zone where the customer is located);
    - Distribution kilowatt-hour charge;
    - Transmission kilowatt-hour charge; and
    - Transition kilowatt-hour charge."

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[24] Class I Net Metering Facility is defined in (63) as "a plant or equipment that is used to produce, manufacture, or otherwise generate electricity and that is not a transmission facility and that has a design capacity of 60 kilowatts or less".

[25] Customers not eligible for net metering are electric companies, generation companies, aggregator, supplier, energy marketer, or energy broker. See Section 18.06 in (63).

[26] Customers applying for net metering must complete "Schedule Z", which it is the net metering application to the distribution company.

In addition to size constraints, net metering is limited to 1% of the utility's historical peak load, considering the aggregated capacity of Class I, II and III. According to the latest information provided by four distribution utilities companies, in Massachusetts there are about 70MW of net metering projects, already online or pending of approval (see Table 2.3-1):

Utility	**National Grid** (65)	**NSTAR** (66)	**Unitil** (67)	**WMECO** (68)
Highest historical peak	5,067MW	4,958MW (August 2, 2006)	102MW (July 27,2005)	845MW (August 2, 2006)
Net metering cap	50.67MW	49.58MW	1.02MW	8.45MW
Projects online	10.783MW	11.79MW	0.24MW	2.4MW
Projects pending	18.968MW	25.84MW	0.05MW	0.1MW
Total	**29.75MW**	**37.64MW**	**0.29MW**	**2.50MW**
% Cap	59%	76%	28%	30%
Date	As of 04/15, 2010	As of 03/31, 2010	As of 3/10, 2010	As of 04/01, 2010

Table 2.3-1: Net metering projects in Massachusetts

The information in Table 2.3-1 shows aggregated net metering projects for all facility classes, with no specific information about micro-CHPs. However, looking at the information of the available interconnection projects in (69), we can estimate the number of micro-CHPs being installed in the state[27] (see Table 2.3-2):

Size < 10kWe	**Number projects** [unit]		**Installed Capacity** [kW]	
	Micro-CHP	PV	Micro-CHP	PV
Period 2008	73	474	97.40	1,894.58
Period 2007	7	333	12.20	1,169.99
Period 2006	9	266	9.00	828.23

Table 2.3-2: Installed and pending net metering projects in Massachusetts for CHP & PV technologies of size less than 10kWe

Although the information is only available up to year 2008, in Table 2.3-2 we see that the number of micro-CHP systems has grown over the last years, with *all reported units using Internal Combustion engines* and mostly natural gas as the fuel source. However, the *penetration is very low* especially when compared to residential photovoltaic systems. We need to point out that in this table we do not see the impact of the net metering policy in the state, as it has been in effect only since December 2009.

In addition to net metering, an alternative energy portfolio standard (APS) in Massachusetts has been in effect since January 2009 [(70) (71)], where it is required to retail electricity suppliers to provide a certain percentage of their sales from alternative energy generating resources. According to (72), some of the eligible technologies are flywheel storage unit, coal gasification, energy efficient steam technology, combined heat and power, among others. In the particular case of CHP,

[27] We extracted the information on those systems with electrical size up to 10kWe.

the state goal is 1% for year 2009, going up to 5% in year 2020. After 2020, the minimum standard increases 0.25% per year.

Finally, we have seen that net metering in MA does not exclude micro-CHPs as an alternative technology for promoting clean energy, and it does not enforce special charges to customers adopting this technology. These different measures being adopted in the net metering program could promote a greater deployment of micro-CHPs within residential customers. However, particular issues of concerns regarding net metering and APS are (i) the limit imposed on the total capacity of the program; (ii) the lack of a more advanced meter that could potentially allow the implementation of real time electricity rates, among other functions; (iii) the monetary treatment of net excess generation (NEG) for wind and solar as opposed to micro-CHPs; and (iv) APS regulation seems to target large commercial, industrial, and institutional facilities and it is not specified whether residential micro-CHP applications can be considered as eligible technologies.

2.3.2. Status in other countries

The UK is one of the leading countries committed to combating climate change and reducing CO2 emissions. The government's goal is to reduce carbon emissions by 60% from 1990 levels by 2050 with significant progress by 2020 (6) and for suppliers to source 15% of their electricity from energy renewable sources by 2015/16 (73). Micro-cogeneration has been recognized as one technology that could help to reach this goal, and currently it is being supported through specific measures such as:

Currently there is an economic support for certain heat generating technologies, and potential government funding for micro-CHPs may be feasible once certified installers and products[28] become available in the market. The funding should be in the form of a grant, with a cap per household, and it should be provided through the Low Carbon Buildings Programme, LCBP (74).

Feed-in Tariff (FiT) is a financial support scheme envisioned in the Energy Act of 2008 and adopted by the government since April 2010 to encourage customers to install small scale, low carbon electricity devices (75) (76). Feed-in Tariffs are tax free and are paid over a period of 10 years minimum. The tariff is available for 30,000 micro-CHP installations, and a review will take place when 12,000 units have been installed. The FiT consists of two parts: a generation tariff and an export tariff.

[28] Certification is done under the Microgeneration Certification Scheme (MCS). See http://www.microgenerationcertification.org/ for more details.

In the generation tariff[29], the electricity supplier makes a fixed payment to the householder for every kilowatt hour (kWh) of electricity generated, whether it is used locally or exported. The tariff level for micro-CHPs under 2kWe is 10 [pence/kWh][30] for year 2010 up to 2013, with a tariff lifetime of 10 years.

In the export tariff, the electricity supplier pays a fixed amount for every kWh of electricity exported by the householder back to the electricity grid. The tariff level is 3 [pence/kWh] on top of the generation payment.

To qualify for FiT, the customer should have a generation meter to record on-site production, and an import meter. An export meter is only required for certain generators, otherwise the amount being exported is estimated.

Currently, micro-CHP using Stirling engine is considered a suitable technology for the UK market as it matches well the energy profile of a typical family home in UK. According to (6), a residential house based on a gas central heating system requires around 18,000kWh/yr of space heating, 5000kWh/yr of water heating, and 3,500kWh/yr of electricity consumption, with a heat-to-power ratio close to 7:1. In addition to this, the UK has a heating season that spreads over several months which requires long running hours of the heating system.

Finally, the major energy suppliers in the UK are working to mass produce and commercialize micro-CHPs to their customers in the near future (either 2010 or 2011). As they are at pre-commercialization stage, up to now there are no information on the current micro-CHP market penetration. However, Stirling engine micro-CHPs are expected to compete with the boiler market, where the market potential has been estimated to be up to 500,000 units per year (6).

The situation in the Netherlands is quite similar to the situation in the UK. Micro-CHP technology is part of the government's energy program to help to develop the path to a more renewable energy future. Several entities such as, government, energy companies and boiler manufacturers are currently involved in promoting and speeding up the penetration of micro-CHP into the market (6). As with the UK, micro-CHPs are direct competition to high efficiency condensing boilers. They are

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[29] According to (75), for other technologies the tariff level is:

Technology	**Scale**	**Tariff level for new installations in period** [pence/kWh]			**Tariff lifetime** [years]
		Year 1: 1/4/10-31/3/11	Year 2: 1/4/11-31/3/12	Year 3: 1/4/12-31/3/13	
MicroCHP pilot	**<2 kW***	**10***	**10***	**10***	**10***
PV	≤4 kW (new build)	36.1	36.1	33.0	25
PV	≤4 kW (retrofit)	41.3	41.3	37.8	25
PV	>4-10 kW	36.1	36.1	33.0	25
PV	>10-100 kW	31.4	31.4	28.7	25
PV	>100kW-5MW	29.3	29.3	26.8	25
PV	Stand alone system	29.3	29.3	26.8	25
Wind	≤1.5kW	34.5	34.5	32.6	20
Wind	>1.5-15kW	26.7	26.7	25.5	20
Wind	>15-100kW	24.1	24.1	23.0	20
Wind	>100-500kW	18.8	18.8	18.8	20
Wind	>500kW-1.5MW	9.4	9.4	9.4	20
Wind	>1.5MW-5MW	4.5	4.5	4.5	20

* Tariff available only for 30,000 units.

[30] As of April 26 2010, one Pence Sterling is equivalent to 0.01544 U.S. dollar. Source: (104)

expected to replace central heating devices, with similar or higher comfort levels delivered by condensing boilers.

The predominant technology in the Dutch market is the Stirling engine-based micro-CHP, as the high heat-to-power ratio seems to best fit the low electricity demand and high heat demand of the residential customers. Micro-CHPs have been in the Dutch market for more than 10 years, although their large size was more suitable for small hotels and hospitals. Since 2008, small size micro-CHPs more suitable for small residential applications have been commercially available. According to (6), if this technology is considered a replacement of traditional boilers, the market potential for micro-CHPs could be up to 50,000 units per year.

2.4. Impacts of micro-CHP into energy systems

An increasing penetration of DERs presents several challenges to the physical infrastructure, the economic operation and planning, and the institutional and regulatory subsystems within the energy system. Frequently, the literature cites several potential benefits from distributed generation such as, economic savings and GHG emissions reductions, investments deferral in network infrastructure, provision of high quality power, energy losses reductions and local voltage support, and increased power supply reliability (refer for example to (8), (9), (10) (11), (12),(13) (14)(15)). In addition, technical concerns have been identified such as voltage regulation, system fault protection, system losses and distribution interconnection upgrades (15) (16), as well as the suitability of the different micro-CHP technology for the diverse residential energy profiles, the inherent characteristics of these technologies, in-house heating system configuration, and local micro-CHP control mode(17). Within economic uncertainties, in(17) the authors recognize costs for electricity suppliers, distribution system operators and micro-CHP owners; micro-CHP investment and operation costs; retail and feed-in electricity tariffs; competing heating technologies within the domestic sector (high efficiency boilers, heat pumps, heat networks, and solar boilers); ICT infrastructure costs; and the implementation of demand response (DR) measures in combination with price differentiation.

In light of these uncertainties, it is suggested in (77) an innovative approach to integrate these resources to the operation and planning of power systems. The authors propose the need to move away from the “fit and forget” approach to a policy of “integrating” DGs into power system planning and operation. To make that integration, it is required an active management (AM) of distribution networks, as well as the provision of auxiliary services by DGs. An AM approach relies on the integration of DG, loads, voltage regulators, compensators, circuit breakers, and controllable network devices in general. AM could provide real-time network monitoring and control to maximize the use of the distribution network. It is noted that if DG participates in supplying energy while displacing generation from central generation, it should also participate in the provision of ancillary services to increase the flexibility and capacity of the electric system in services such as frequency response, short-term reserve[31], and security of supply. The authors point out that

[31] Used for generation contingency events and demand forecasting errors.

small size DGs such as micro-CHPs may be more suitable for the provision of reserve services.

In the particular case of micro-CHPs, their effects on energy systems and individual residential customers have been studied from several points of view. In this section, we review previous work that has been done within the economic and regulatory areas of knowledge, in an effort to understand the effects when deployed at small and/or large scale.

2.4.1. Effects of a small-scale penetration

The effects of micro-CHPs when deployed in small numbers have been extensively studied. In general, various authors have found that micro-CHPs bring economic savings and emissions reductions to residential customers when results are compared to the traditional model of producing heat and purchasing electricity to the utility company. It has been shown that these savings vary depending on the technology being in place, as well as the householder energy profile, energy prices, and potential economic compensation for excess of electricity fed into the grid.

For example in (17), the authors examine the maximum potential savings of one average household operating a micro-CHP system. It is recognized that the design and operation of micro-CHPs is surrounded by technical, economic and institutional uncertainties. Based on The Netherlands energy market, the authors quantitatively analyze the impacts of a set of uncertainties to a specific case study based on a household/energy supplier system, where customer's heat and electricity demand requirements are supplied by a SE micro-CHP, auxiliary burner, hot water storage, electricity supplier (who also sells fuel) and a battery. Using average energy demand profiles from the Netherlands market and 3 selected days, sensitivity analyses are done over economic parameters (energy prices), technology characteristics (storage availability and capacity, up-times), and energy profiles. Using a least-cost control strategy, the system model determines the actions to take in order to minimize the daily energy operational costs subject to constraints. Finally, this particular case study shows that:

- In general, a micro-CHP system leads to lower costs, less imported electricity, and less CO2 when compared to a conventional case with no micro-CHP and distributed heating system. Results show the same tendency for each seasonal day and pricing regime although costs and CO2 emission savings are leas for the summer day due to the low heat demand.
- Increasing electric battery capacities decrease energy operational costs.
- A micro-CHP case with variable feed-in tariff gives higher cost savings than the case with fixed feed-in tariff.
- Households with micro-CHP systems with lower gas tariffs can result in more than proportional total cost savings.
- Heat storage capacity size showed to have a reasonable influence on energy costs. However, a system with heat storage had lower costs, CO2 emissions, less electricity import and more CHP generated power (compare to s system without).

The authors finish by arguing that the incorporation of more information and communication technology (ICT) could allow a more intelligent control of the networks and DERs, enabling an active and greater consumer's participation in the energy system.

In (7), the authors examine the impact of energy efficiency policy measures in the UK - such as residential thermal insulation - on the economic and environmental performance of micro-CHPs. It is found that simultaneous support for efficiency measures and micro-CHP can be justified, but care must be taken to ensure that the heat-to-power ratio and capacity of the micro-CHP system are appropriate for the householder thermal demand. The authors investigate FC, ICE and SE micro-CHPs for different residence types (i.e. terraced, detached, etc.) with different thermal insulation categories (i.e. existing, refurbished and new dwellings). In addition to the thermal insulation categories, three electricity demands are investigated - small, average and large. Economic and environmental results, based on the equivalent annual cost (EAC)[32] and carbon dioxide emissions, show that the more insulated the dwelling, the less convincing the case for investment in micro-CHP (i.e. EAC savings reduced with increasing insulation). Regarding emissions, in general micro-CHPs reduce the CO2 emissions and expected emission savings reduce as insulation improves. They also show that FCs result with the largest emissions reduction, followed by ICE, and then SE micro-CHPs. FCs perform well regardless of the insulation level, while SEs and ICEs emissions savings is substantially reduced as insulation improves. Finally, the analysis suggests that government policy supporting both energy efficiency measures and micro-CHP can be justified, but care needs to be taken to avoid supporting high heat-to-power ratio technologies in dwellings that have low or inconsistent heat demand. For example, a high heat-to-power ratio SE technology in a new highly insulated flat could result in higher cost for the householder, and insignificant CO2 emissions savings.

In (18) the authors study three types of micro-CHP technologies for residential use In Belgium. Based on five micro-CHP systems (2 ICEs, 2 SEs, and 1 FC) with a capacity lower than 5kWe and detailed simulated energy profiles, a comparison is made with a traditional energy system that uses a natural gas boiler and buys electricity from the grid. Similar to the results discussed above, different technologies show different performances, but in general all of them reduce primary energy use, reduce CO2 emissions and bring economic savings when the micro-CHP operates on heat-lead for the different type of buildings. For most micro-CHPs, annual savings turn out to be low under the particular circumstances and assumptions of this study. Finally, the authors conclude that installation costs are still too expensive, and they should reduce by 50% at least before micro-CHPs become interesting for residential use.

[32] EAC is the combination of annualized capital cost, maintenance cost, plus the cost of fuel and electricity consumed (boiler and micro-CHP), minus the revenue from selling electricity back to the grid.

2.4.2. Effects of a large-scale penetration

Regarding the effects of micro-CHPs when deployed at large scale, studies focusing on an economic and regulatory approach are more difficult to find. Assessment studies have focused on distribution network costs, technical effects on a particular distribution network, and the potential micro-CHP contribution to reliability, among others.

For example, in (19) a quantification of DG effects on distribution network costs is described in three case studies. Using Reference Network Models (RNMs) or optimally adapted networks, a network is designed taking into consideration demand growth, DGs, geographic information, etc. while minimizing the costs of the network (i.e. investments and maintenance costs, and energy losses). The models work with very large areas comprising up to several million customers. In the study, different scenarios were analyzed, with one of them focusing on the development of domestic PV panels and domestic CHPs connected at LV level in an urban area in Germany. According to the authors, by 2020 it is expected that between 25% and 50% of the 6,100 households could have a 1.1kW micro-CHP unit totaling between 1.7MW and 3.4MW of installed capacity. The results show that the total distribution network costs increase with larger DG penetration, as greater network capacity and circuit length are required. It is noted as well that under large DG penetration levels, network costs are higher for low demand levels than for high ones, which indicates that consumption reduces power flows and capacity requirements at periods of maximum generation.

In (20), some technical effects of a large-scale penetration of micro-CHPs on the distribution network are explored. The discussion focused on three different micro-CHP technologies and the potential voltage rise they could cause on the electricity system. It is recognized that individually, micro-CHPs have negligible effects on distributions networks. However, a large number in close geographic proximity could have a significant collective effect. The authors present a case study based on a particular network located in the UK, supplying electricity to about 1,200 domestic households. The model uses one-minute demand data, diversified across residential properties[33], where the aggregated demand provides a smooth demand curve. Individual heat demand profiles are generated using normal distribution based on measured data. The study assumes that each dwelling has a particular micro-CHP that adopts an on/off heat-led operation, with full rated electrical output when the unit is on. Demand and generation profiles are generated for all the properties, and during several periods of the day power export occurs. When considering the profiles in other properties, power flow in local sections of the network is sometimes reversed. Using these demand and generation profiles, a network power flow simulation is performed to calculate voltages, currents, energy losses, among other results. Results show that, with large-scale micro-CHP penetration, there is the possibility of voltage rise at different connection points throughout the network. In addition, micro-CHPs with larger electrical outputs (i.e. 3kWe) bring more voltage rise than those 1kWe-size micro-CHP units. Regarding the losses in the system, it is

[33] Individual demand profiles are diverse and highly stochastic.

shown that they are reduced by the introduction of micro-CHPs except for the case of vey high energy penetration.

In (21) the authors investigate the potential capacity credit of micro-CHP in order to understand the overall system influence of this technology in terms of reliability of supply. Capacity credit is a metric used in electric power system planning that measures the amount of conventional generation that would be displaced by an alternative technology while maintaining the reliability of the system. The study uses SE, ICE, and FC based micro-CHPs under 3 operating strategies: electricity-led, heat-led, and least-cost strategies. Different penetration levels are simulated, ranging from 1 million to a maximum of 13 million units. Under the particular conditions assumed for the UK market, it is found that low heat-to-power ratio technologies achieve the highest capacity credit, followed by ICE, and SE micro-CHPs. The reason is because FC micro-CHPs are able to continuously produce electricity even when heat demands are relatively low. In addition it is shown that the least-cost operating strategy achieves the highest capacity credit, followed by heat-led operation. In particular FCs achieved about 85% capacity credit, while SEs achieved about 33% capacity credit for heat-led operation at 1.1GW penetration. The authors mention that critical to these results is the coincidence of the national peak electricity demand with the residential demand which occurs in winter.

Finally, in (22) the authors investigate the effects of micro-CHPs on the energy flows and peak load on a particular electricity system under a heat-led control strategy for SE and FC technologies. The authors used recorded residential energy demand data for several dwellings, analyzed the system for three particular days (winter, spring, summer), and focused the analysis on the effects on a transformer in the LV network serving domestic users. Results showed that at the level of the single dwelling, demand was reduced by 25% for a SE (1kWe) and by 46% for FC (3kWe) micro-CHPs. The operational performances of micro-CHPs are highly seasonal, with larger differences for the SE than for the FC system. In particular, it is seen that SE reduces the amount of energy imported from the network by 39% during winter, while 10% during summer. The FC micro-CHP achieves reductions of 43% and 28% during winter and summer respectively. At the system level (i.e. groups of residential customers), it is seen that the deployment of 1kWe SE micro-CHP does "not lead to any significant reverse flows through the distribution transformer until the penetration level exceeds about 50%". In the case of 3KWe FC micro-CHP, results showed that in addition to reduce load it would "result in significant export flows, for penetration levels of greater than about 40%". In addition, micro-CHP deployment reduces network use at times of peak demand during winter, where heat demand is highly coincident with the electrical demand for the case being studied.

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CHAPTER 3

OPERATION OF MICRO-CHP SYSTEMS AT A HOUSEHOLD LEVEL

At the residential level, small CHPs are expected to penetrate the market as highly efficient heating systems capable of producing not only heat, but also electric power. Fuel conversion efficiency may range from 80% up to over 90%. This particular characteristic and the fact that the technology is already being commercialized have made small-CHPs attractive to be part of short-term energy policies aimed at reducing GHG emissions and increasing energy efficiency.

Currently, the most common configuration is a heating device such as furnace or boiler to produce heat for space heating and domestic hot water, and electricity would be purchased to an electric power utility company or broker delivered through the electric distribution grid.

Small-CHPs can be installed as retrofits of older heating systems, or as part of new systems. Under this configuration (shown in Figure 3. 1) micro-CHPs would produce electric power and heat when needed as opposed to the traditional configuration without micro-CHP[34].

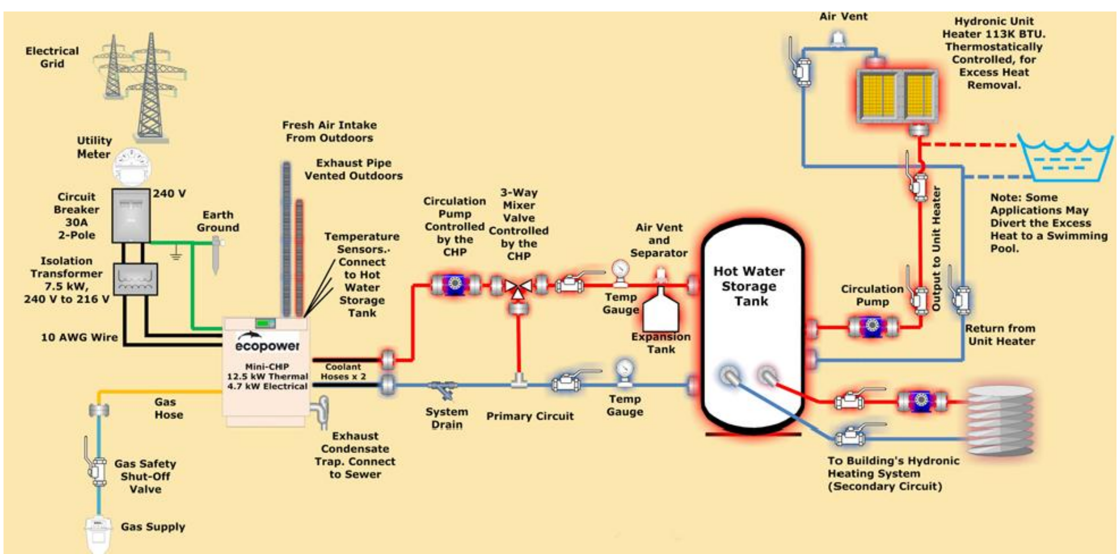

Figure 3. 1: Heating system with small-CHP

[34] Source: Marathon Engine Systems.

An overall representation of an energy system with micro-CHP units can be thought as located downstream the electric and natural gas networks (shown in Figure 3. 2).

Although the costs of small-CHP systems with respect to conventional heating systems are still expensive, it is expected in the near term a greater penetration of these systems as governments offer subsidies and tax incentives as part of their energy policies.

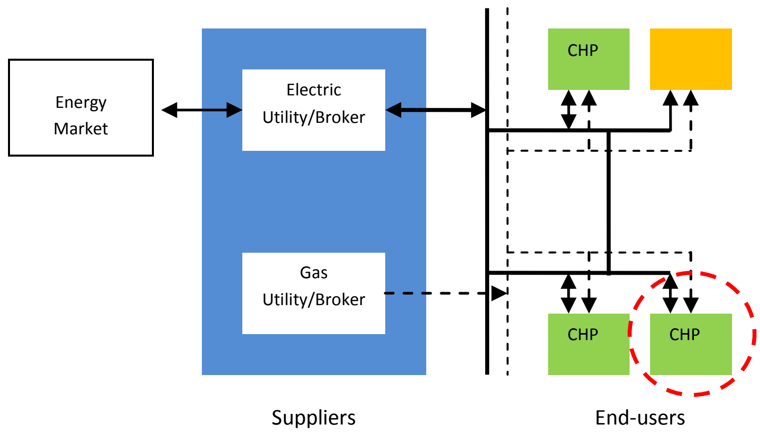

Figure 3. 2: Energy system representation with micro-CHPs

As more small-CHP systems are installed, it is of interest to understand the operational strategy that micro-CHP will adopt and the coordination regime that, if any, will be adopted. Strategies may range from technology-based thermal led and power led operations to a more intelligent least cost-based operation. As the number of micro-CHPs grows, a better coordination may be required to improve the energy system operations and planning, facilitate commercial transactions, and address environmental concerns among other issues. Therefore, coordination regimes may range from a decentralized local-level[35] (dotted red circle in figure) to a centralized system-level approach. In the first case, the micro-CHP operation will be based upon the household individual decision, which may rely on factors ranging from heat comfort-level to more sophisticated ones such as costs reduction or environmental concerns. In the second case, the micro-CHP operation will depend upon a centralized decision based on a system-level performance.

Throughout this chapter, we will focus on the modeling the micro-CHP operation under a decentralized coordination regime. The purpose will be to understand the local impacts of a micro-CHP-based system opposed to a conventional system without micro-CHP.

[35] This case is the current trend for operating small-CHPs. The only interaction with the utility company is at the time of connecting the unit to the electric system, when there are abnormal conditions in the grid, and in the case where power surplus is remunerated.

3.1. Decentralized micro-CHP operation model formulation

In this section, we will describe the mathematical formulations used for understanding the micro-CHP operations. The models will be based on three control-strategies: stringent heat-led, stringent electricity-led and intelligent-control, under a decentralized coordination regime.

Under both stringent-control cases, the household programs the micro-CHP to run following the heat load or power load respectively. Under the intelligent-control strategy, the residential customer bases his decision not only on the energy load, but also on the energy prices. Thus, through on-site generation, users are able to respond to the economic signals provided by the energy prices.

First, we will explain the main characteristics of a residential heating system that combines a micro-CHP and the inputs we will need for the formulations. Then, based this configuration we will examine three model formulations used for understanding the local impacts when operating a micro-CHP system. Finally, we will describe the simplifications adopted throughout the operational models.

3.1.1. Representation of a micro-CHP based heating system

Small-CHPs as part of the household heating system can have different applications. In warm-air heating applications, forced warm air from the micro-CHP unit and auxiliary gas-fired furnace is used for central space heating only. On the other hand, in hydronic heating applications, stored hot water from micro-CHP unit and auxiliary gas-fired boilers combined with a hot water tank is used for space heating and domestic hot water for sanitary purposes.

In addition, as explained in Chapter 2, there are different technologies used as the prime movers for small-CHPs ranging from Internal Combustion Engines (ICE), Free Piston Sterling Engines (SE), and Fuel Cells (FC). Different engines will result in dissimilar power and heat capacities, fuel conversion efficiencies and heat to power ratios, among other characteristics.

In Figure 3.1.1 we depict a residential heating system based on a hydronic, i.e. hot water, configuration. Here an ICE-based micro-CHP will produce electricity (e^{chp}) and heat (h^{chp}) at a fixed heat-to-power ratio. Since the machine is connected to the electric power grid, on one hand if the generated electricity is beyond the local demand (e^{load}) then the excess is exported back to the grid ($e^{\exp}$); on the other hand if electricity is below current demand then a supplement is imported from the grid (e^{imp}). In addition, the micro-CHP complements its operation with a hot water tank (h^{tank}) and an auxiliary boiler (h^{aux}) which deliver heat for space heating and domestic hot water (h^{load}). The tank gives the system the flexibility to store heat and using it later when needed.

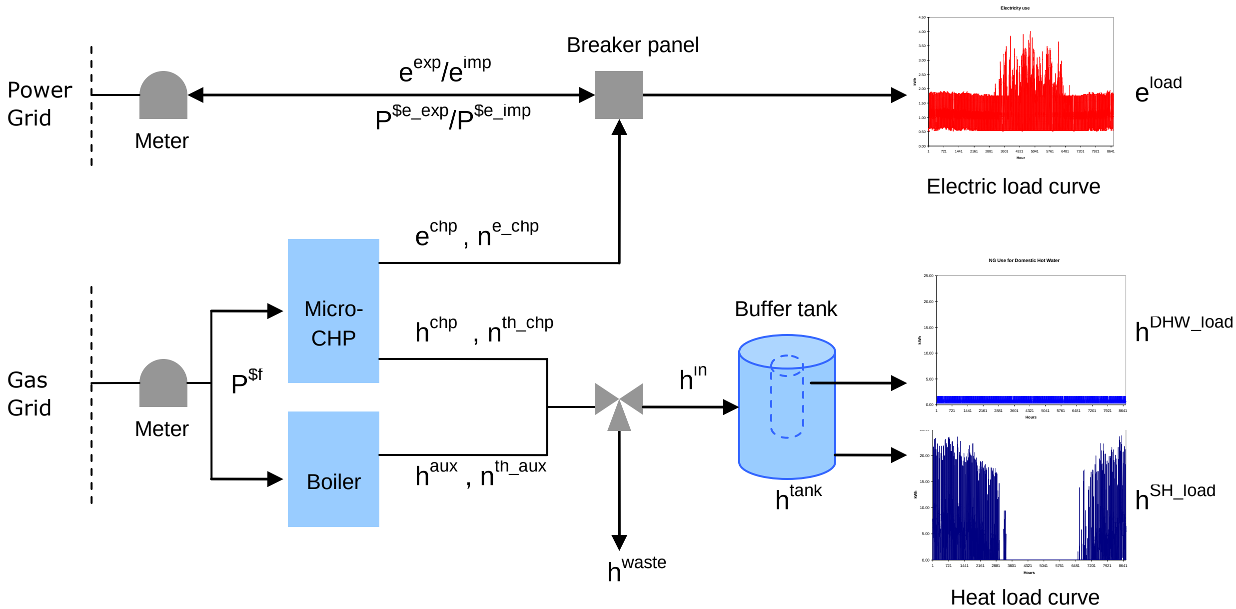

Figure 3.1.1: Residential heating & electric system using a micro-CHP unit under a hot-water configuration

We took this configuration as a starting point for constructing the mathematical formulations that would represent a decentralized micro-CHP operation at the residential level (see "Appendix A.1. Glossary of terms").

3.1.2. Key modeling inputs

A central part of the formulations, it is the input data we require. As we will explain, some information comes from manufacturers, others from historical records, while others from simulators due to the lack of comprehensive data.

There are three main inputs that the models require:

- Technology-related parameters, which depend on the type of micro-CHP and heating system applications.
- Residential electric power and heat demands on an hourly basis, which reflect the load patterns of householders living in a house of a particular size located at a specific climate zone.
- Retail electricity and fuel prices on an hourly basis, which may reflect current or future end-users retail tariff schemes.

3.1.2.1. Technology-related parameters

The technical parameters assumed for the formulations are based on the Ecopower MicroCHP system developed by Marathon Engine Systems, a US-based company[36]. As shown in Figure 3.3 above, the heating application is assumed to be hydronic, i.e. hot water-based. In addition, the ICE-based micro-CHP is connected to the power grid and to the natural gas network.

[36] Information provided by manufacturer.

This particular micro-CHP has the capability to generate three different levels of electric power as it has three different engine speeds. The heat-to-power (HPR) ratio was assumed to be about constant for the entire performance range. Table 3.1-1 shows the micro-CHP power and heat outputs:

CHP engine speed	Power	Heat	HPR
1200 rpm	1.37kWe	3.7kWth	2.7
1900 rpm	2.37kWe	6.4kWth	2.7
3400 rpm	4.70kWe	12.5kWth	2.7

Table 3.1-1: Micro-CHP energy outputs

Regarding energy efficiency of the machine, although the total efficiency will range between 87.4% up to 91.2% depending on the speed rate, for the formulations we will assume constant values as shown in Table 3.1-2.

CHP	Efficiency
Electric	24.4%
Thermal	66.8%
Total	**91.2%**

Table 3.1-2: Micro-CHP energy outputs

Under the hot water-based application, the heating system will require in addition a gas-fired boiler and a buffer hot water tank. These auxiliary equipments will allow meeting peak thermal loads and giving flexibility to the system for varying loads, respectively. The auxiliary boiler was assumed to be high efficient, fully modulating, and with enough capacity to cover the heat annual peak demand (see Table 3.1-3).

Boiler	
Thermal output	0 – 25kWh_{th}
Thermal efficiency	95.0%

Table 3.1-3: Boiler characteristics

The hot water buffer tank was assumed to be highly insulated (i.e. no tank losses), and a size of about 40 gallons. The energy heat capacity at 70°F environment temperature was calculated to be about 5kWh[37] for a 40 gallons tank (see Table 3.1-4).

Buffer hot water tank	
Heat capacity, 40 gal	0 – 5kWh_{th}
Losses	0%

Table 3.1-4: Buffer tank characteristics

3.1.2.2. Hourly energy demands

For the simulations we need typical energy load profiles per hour for residential dwellings during one year timeframe. We found it difficult to get a comprehensive dataset. For example some of them are expensive proprietary databases, and others are test-field measurements for a particular time of the year and particular climate zone. Some electric utility companies have publicly available customer's load profiles in their websites. However, these are based on load research samples that are small in number and over a limited number of customer classes. The problem with these datasets is that individual load profiles are rough calculations based on those samples, and there is no information on the particular customer such as house size, number persons, and heating and cooling systems. Finally, we were not able to find datasets containing natural gas consumption or heat load profiles on an hourly basis.

Given these issues, we decided to create the data using an energy simulation and load calculation software suitable for small buildings. Energy-10™-version 1.8 was developed by the National Renewable Energy Laboratory's (NREL) Center for Building and Thermal Systems, and currently is licensed to Sustainable Buildings Industry Council (SBIC). The software performs hourly energy calculations over one full year.

Although Energy-10™ has numerous features mostly related to energy efficiency design practices, we limited the calculations to look into reference cases that would represent U.S. national average energy consumptions. Within this analysis, we used the feature that we can place our model-house in different cities in the US. Therefore, we were able to include in the simulations weather variations, with minor adjustments to the construction materials, depending on the climate zone (CZ) where the house was located.

[37] For heat capacity calculations we used:
- Tank size: 40gal.
- Tank minimum temperature: 120°F (domestic hot water delivered at this temperature).
- Tank maximum temperature: 180°F (hot water for space heating stored at high temperature).
- Environment temperature: 70°F (comfort setting used inside the house).
- Water specific heat capacity: 1Btu/lb°F.
- Water density: 8.29lb/gal.
- Energy unit converter: 3412.8Btu/Kwh.

The calculated minimum heat capacity is 4.85kWh, and maximum capacity is 10.68kWh for a 40gal tank.

In particular, we created a model-house with the following main characteristics:

Characteristics of model-house	
Floor area	2,500 ft2
Maximum number of people	6
Heating system	Gas furnace
Heating thermostat	70°F between 7am and 11pm
Heating setback	65°F other times
Cooling system	Direct expansion compressor
Cooling thermostat	78°F between 7am and 11pm
Cooling setup	83°F other times
Fan/air distribution	Forced air
Load profiles[38]	Generated by Energy-10™
Location & Climate zone (CZ)	Boston, MA (CZ 6A) Fargo, ND (CZ 7A) New Orleans, LA (CZ 2A)

Table 3.1-5: Model-house characteristics used by Energy-10TM simulator

As we can see in the last row of Table 3.1-5, we located our model-house in three different cities. Therefore, we simulated different scenarios where we obtained three energy demand datasets.

[38] In Enegy-10™, load profiles give time-of-day information of the model-house energy demand. These profiles are generated hour by hour based on the end-use monitoring program at Pacific Northwest Laboratory (PNL) which collected data from many buildings for the End-Use Load and Consumer Assessment Program (ELCAP). Then, based on ELCAP profiles and the national average energy consumption reported by the EIA- Energy Consumption Survey for different building categories, Energy-10™ calculates "peak gains values" used later on to generate the load profiles (peak gains are in Watt/ft^2). Finally, these profiles are generated to reflect energy use in 4 categories: internal lights, external lights, hot water, and plug loads such as computers, appliances, refrigerators, and cooking loads. Then, electricity use for internal lights, external lights and plug loads is calculated as (peak value)*(floor area)*(profile value)*10.

In Figure 3.1.2 we can see the hourly energy demands for our model-house located in Boston, which is the case studied in this dissertation.

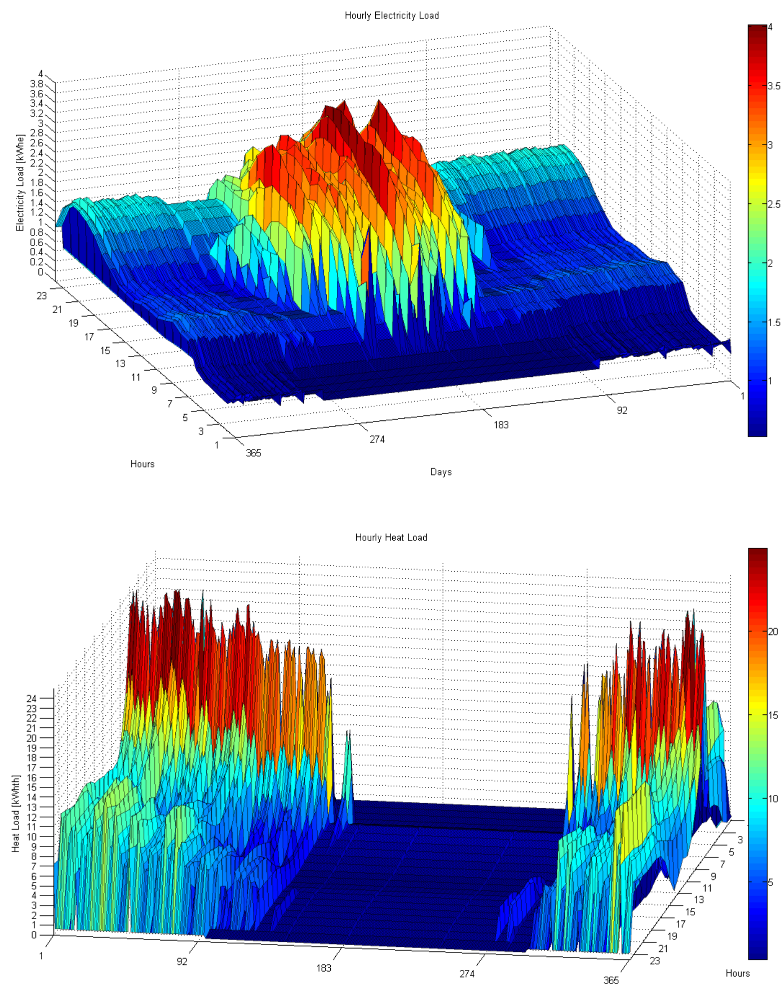

Figure 3.1.2: Hourly electric and heat demands during one year
Results are based on Energy-10TM outputs, for a house located in Boston in [kWh/h]

3.1.2.3. Hourly energy prices

Understanding the operation of micro-CHP systems will require also understanding the pricing scheme retail customers owning micro-CHPs will get. As the machine is connected to the grid, the micro-CHP will work in parallel to the electric power system. Therefore, at some times the customer may require importing electricity for meeting local power demand. At other times the user may export electricity when the micro-CHP produces excess power beyond his current demand.

At this point it is not clear the pricing scheme that users with micro-CHP will have. Therefore, the model formulations require as input energy (power and gas) prices on an hourly basis that may allow future varying energy prices (such as some type of time-of-use or real-time pricing). For electricity prices we need import and export prices. Electricity import prices should reflect the retail price that householders pay to utility companies that supply and deliver electric power, while electricity export prices should reflect the value of the power being exported back to the grid. In addition, the model also needs natural gas prices at the retail level that users require to pay to the gas utility company for fuel purchases.

Given this uncertainty, at first we assumed that end-users will be merely price takers with no influence on the energy price market. In addition, to begin with, we assumed monthly retail tariffs for residential customers. We took these values from historical public data posted on utility companies and independent system operators' websites:

a. Import electricity price.

$$P^{\$e\_imp} = Supplier\ service\ charge^{1} + Delivery\ service\ charge^{2}$$

Where (1) *Supplier Service Charge* is the variable option for electricity default service per month; and (2) *Delivery Service Charge* is the sum of distribution, transition, transmission, energy conservation and renewable energy charges per month [$/kWh]. In this definition we did not include the monthly fixed charge[39].

b. Export electricity price.

$$P^{\$e\_\exp} = P^{\$e\_imp} - 1¢ / kWh$$

For now we assumed an arbitrary export price to be 1¢/kWh cheaper than the electricity import price.

c. Natural gas price.

$$P^{\$f} = Supplier\ service\ charge^{1} + Delivery\ service\ charge^{2}$$

Where (1) *Supplier Service Charge* is the cost of gas adjustment per month; and (2) *Delivery Service Charge* is the sum of distribution and local distribution adjustment charges. In this definition we did not include the monthly fixed charge, and for delivery charge we only took the first 20 therms distribution charge[40].

[39] Source: Values based on NSTAR rates for Boston, 2007 and 2008 http://www.nstaronline.com/ss3/residential/account_services/rates_tariffs/rates/rates.asp.

[40] Source: Values based on KeySpan rates for Boston, 2007: (1) KeySpan rates for Boston, Customer & distribution charges: http://gasrates.keyspanenergy.com/ne/NEGasrates/NEGasratesController.
(2) DPU Mass, GAF & LDAF for KeySpan Boston: http://www.mass.gov/ (Cost of Gas Adjustment Information).

As a result, the assumed monthly energy prices and feed-in tariff according to the historical utility gas and electricity retail rates in the area of Boston are shown in see Figure 3.1.3 below (see Appendix A.2 and A.3 for details):

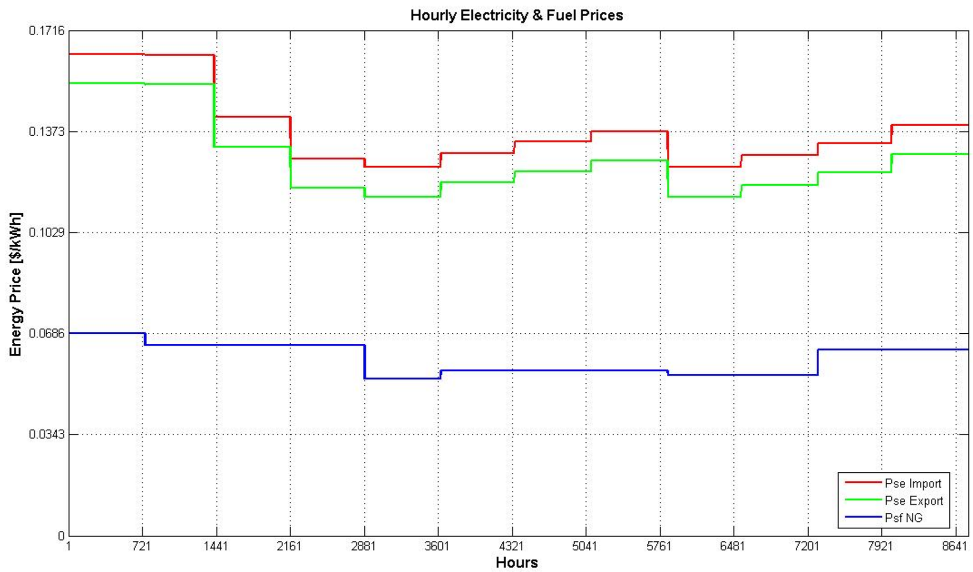

Figure 3.1.3: Assumed monthly energy prices based on utility historical rates

Red line shows import power rate. Green line shows feed-in tariff.

Blue line shows natural gas retail tariff. Prices in [$/kWh]

Finally we recognize that the connectedness to the electric power grid requires us to think on how the measurement and processing of the data will be performed. Net metering, for example, will only record the power net value at the end of a particular month. Under this mechanism, shorter time variations will not be registered and potential benefits or hidden cost of innovative systems like micro-CHPs may not fully recorded.

Having in mind the above, for the formulations we will assume that users have digital smart meters able to record the power and natural gas usages[41] on an hourly basis and that customers have access to that information via the Internet. In addition, we will also assume that, besides having access to energy usage, users will have access in advance to price information that may help them to decide the optimal operation of the micro-CHP unit. We need to note that for the stringent-control formulations energy prices do not play a role on the customer's operational decision. However, for the intelligent-control strategy this information will be fundamental for deciding how best to meet his energy needs.

In the following sections, we will explain the mathematical formulations of the three control-strategies a micro-CHP may adopt.

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[41] See for example: http://www.sdge.com/smartmeter/

3.1.3. Stringent-control strategy formulation

Under a stringent strategy, the operation of the micro-CHP unit is based on its technological characteristics, and the energy load conditions. The machine runs according to local physical signals such as the residential electric load or the heat load. For both formulations we took one year as operational horizon, and the simulations were done on an hourly basis.

3.1.3.1. Heat-led control

Under this control strategy, the micro-CHP is based on the hourly heat load. Depending on the thermal load, the micro-CHP will run within its capacity limits and, if needed, supplemental heat will be provided by the auxiliary boiler. In case the production is greater than the current demand, that excess heat will be stored in the buffer tank to be used in the following hour. In addition, if the excess exceeds the tank heating capacity then the remaining is discarded.

Thus, the heat-led control follows the following rationale:

a. At the beginning of the micro-CHP operation we assume the initial tank condition to be 0kWh of heating: $h_{t=1}^{tank} = 0$

b. The net heat load taken as reference will be the current load after discounting the heat stored in the tank at the same hour. If there is enough heat in the tank to cover the entire load, then the net load will be 0kWh: $h_t^{load'} = max(h_t^{load} - h_t^{tank}, 0)$. In addition, the remaining heat not used for supplying the load will be left in the tank for future use: $h_t^{tank\_after} = max(h_t^{tank} - h_t^{load}, 0)$

c. The operational level of the micro-CHP will depend on the amount of heat to supply. As the micro-CHP has three discrete outputs, if the net heat load is below 10% of the maximum capacity then the machine will not run. The machine will operate at an output level superior to the net heat. If the load if greater than the maximum output, the micro-CHP will operate up to full capacity:

$$h_t^{chp} = \begin{cases} 0 & if\, h_t^{load'} \le 10\% \cdot H^{chp4} \\ H^{chp2} & if\, 10\% \cdot H^{chp4} \le h_t^{load'} \le H^{chp2} \\ H^{chp3} & if\, H^{chp2} < h_t^{load'} \le H^{chp3} \\ H^{chp4} & if\, H^{chp3} < h_t^{load'} \end{cases}$$

d. The operation of the auxiliary boiler will complement that of the micro-CHP. Thus, if the load is too small for the micro-CHP to run or if the load is larger than the machine capacity, then the boiler will provide the additional heat. The boiler output was assumed to be continuous and it can modulate the load:

$$h_t^{aux} = \begin{cases} h_t^{load'} & if\, 0 \le h_t^{load'} < 10\% \cdot H^{chp4} \\ h_t^{load'} - H^{chp4} & if\, H^{chp4} < h_t^{load'} \end{cases}$$

e. After meeting the net heat load with the micro-CHP, boiler and heat from buffer tank we need to store any excess heat for using the next hour. The tank can store heat up to 5kWh:

$$h_{t+1}^{tank} = \begin{cases} \left(h_t^{chp} + h_t^{aux} + h_t^{tank\_after}\right) - h_t^{load'} & if \left(h_t^{chp} + h_t^{aux} + h_t^{tank\_after}\right) - h_t^{load'} \leq 5 \\ 5 & if \left(h_t^{chp} + h_t^{aux} + h_t^{tank\_after}\right) - h_t^{load'} > 5 \end{cases}$$

f. Any excess heat that was left out of the buffer tank because of capacity limit will be discarded as waste: $h_t^{waste} = max\left\{\left(h_t^{chp} + h_t^{aux} + h_t^{tank\_after} - h_t^{load'}\right) - 5, 0\right\}$

Finally, the electricity output of the micro-CHP will be a by-product of the heat-led operation, which its value will depend on the HPR of the machine: $e_t^{chp} = \frac{h_t^{chp}}{\mathrm{HPR}}$. In case the produced electricity is not enough, the user will need to import electricity from the grid: $e_t^{imp} = max\left(e_t^{load} - e_t^{chp}, 0\right)$. In case the generated electricity exceeds the power demand, the excess will be exported back to the grid: $e_t^{exp} = max\left(e_t^{chp} - e_t^{load}, 0\right)$

3.1.3.2. Power-led control

Under this control strategy, the micro-CHP is based on the hourly electricity load. Depending on the power load, the micro-CHP will run within its capacity limits and, if needed, supplemental power will be purchased to the utility company. In case the power generation is greater than the current demand, that excess power will be sold back to the power grid at certain feed-in tariff.

The electricity-led control follows the following sequence:

a. The micro-CHP has three possible discrete outputs than will depend on the amount of load to be met. In general, the micro-CHP will operate at a level superior to the current power load. However, if the electricity load is below 10% of the maximum capacity, then the machine will not run. Also, if the load if greater than the maximum output, the machine will operate up to full capacity:

$$e_t^{chp} = \begin{cases} 0 & if\, e_t^{load} \leq 10\% \cdot E^{chp4} \\ E^{chp2} & if\, 10\% \cdot E^{chp4} \leq e_t^{load} \leq E^{chp2} \\ E^{chp3} & if\, E^{chp2} < e_t^{load} \leq E^{chp3} \\ E^{chp4} & if\, E^{chp3} < e_t^{load} \end{cases}$$

b. In case the produced electricity is not enough, the user will need to import electricity from the grid: $e_t^{imp} = max\left(e_t^{load} - e_t^{chp}, 0\right)$.

c. In case the generated electricity exceeds the power demand, the excess will be exported back to the grid: $e_t^{exp} = max\left(e_t^{chp} - e_t^{load}, 0\right)$

Regarding the heat management within the system, under this strategy the heat will be a by-product of the generated power. Therefore, the heat produced by the micro-CHP will depend on the HPR of the machine: $h_t^{chp} = e_t^{chp} \cdot \mathrm{HPR}$. If needed, heat will be produced by the auxiliary boiler when heat from the micro-CHP is below the net heat load[42]: $h_t^{aux} = \max\left(h_t^{load'} - h_t^{chp}, 0\right)$. Then, the operation of the buffer tank will be similar to that under the heat-led strategy (refer to above section for explanation):

$$h_{t=1}^{tank} = 0$$

$$h_t^{tank\_after} = max(h_t^{tank} - h_t^{load}, 0)$$

$$h_t^{load'} = max(h_t^{load} - h_t^{tank}, 0)$$

$$h_{t+1}^{tank} = \begin{cases} \left(h_t^{chp} + h_t^{aux} + h_t^{tank\_after}\right) - h_t^{load'} & if \left(h_t^{chp} + h_t^{aux} + h_t^{tank\_after}\right) - h_t^{load'} \leq 5 \\ 5 & if \left(h_t^{chp} + h_t^{aux} + h_t^{tank\_after}\right) - h_t^{load'} > 5 \end{cases}$$

$$h_t^{waste} = max\left\{\left(h_t^{chp} + h_t^{aux} + h_t^{tank\_after} - h_t^{load'}\right) - 5, 0\right\}$$

Once we compute the energy outputs for both stringent-control strategies, we estimate the amount of fuel being consumed on-site. This value will depend on the fuel conversion efficiency of the micro-CHP and auxiliary heating equipment (66.8% and 95% thermal efficiency respectively):

$$fuel_t^{total} = fuel_t^{chp} + fuel_t^{aux} = \frac{h_t^{chp}}{\eta_{th}^{chp}} + \frac{h_t^{aux}}{\eta_{th}^{aux}}$$

Finally, having hourly fuel ($P_t^{\$f}$) and energy prices ($P_t^{\$e\_imp}, P_t^{\$e\_\exp}$) as inputs, we calculate the energy variable costs of meeting power and thermal loads. Therefore, under the decentralized heat-led or electricity-led control strategies, the total annual cost [$/yr] will be given by:

$$Energy\ variable\ cost = \sum_{t=1}^{8760}\left(P_t^{\$e\_imp} \cdot e_t^{imp} - P_t^{\$e\_exp} \cdot e_t^{exp} + P_t^{\$f} \cdot fuel_t^{total}\right)$$

Where $P_t^{\$e\_imp} \cdot e_t^{imp}$ is the variable cost of buying electricity from the power grid, $P_t^{\$e\_\exp} \cdot e_t^{\exp}$ is the variable income for selling back electricity to the grid, and $P_k^{\$f} \cdot fuel_t^{total}$ is the variable fuel cost.

3.1.4. Intelligent-control strategy formulation

The last formulation it is such that the operation of the micro-CHP is based on economic signals and current energy load conditions. Under this strategy, it is assumed that the householder will optimize his short-term profits over one year. Depending on how sophisticated the information and communication systems are, the micro-CHP owner may have information regarding current o future market conditions and base his operational decision on that[43].

[42] Net heat load will be the current load after discounting the heat stored in the tank during the same hour.

[43] We need to note that, as we will explain later, this formulation is used for the short-term large-scale deployment model (Chapter 5 and 6) . However, the optimization is done for each day separately, instead of doing it for one entire year as it is formulated in this chapter.

Therefore, under an intelligent least-cost criterion, the user will operate the machine only if it is more cost-effective turning on the micro-CHP for generating power and heat than buying power and fuel separately for meeting his energy demands. The profits are based on variable operational costs and income from operating the small-CHP unit.

a. Mathematical formulation.

The decentralized operation problem is seen as an optimization problem, where the objective function is the householder's short-term profit over one year time horizon. Here, we maximize customer profits which are based on variable operational costs and incomes from operating the small-CHP unit and auxiliary heating equipment. The model decides the least-cost operation of the small-CHP unit under a decentralized profit objective.

Mathematically, the problem can be described as a dynamic optimization problem, where the dynamics are given by the hot water storage unit at every stage. As we explain later, the cost function at each feasible state is defined as a mixed integer linear problem and it is solved using lp_solve v5.5.0.12[44].

b. Objective function.

The model maximizes a householder's profits given by:

$$Max\pi = \sum_{k=1}^{8760}\left(-P_k^{\$e\_imp} \cdot e_k^{imp} + P_k^{\$e\_\exp} \cdot e_k^{\exp} - P_k^{\$f} \cdot \frac{h_k^{chp}}{\eta_{th}^{chp}} - P_k^{\$f} \cdot \frac{h_k^{aux}}{\eta_{th}^{aux}} - Pen \cdot h_k^{waste} \right)$$

Where,

π is the user's short-term profit function over 1 year time horizon [$/yr]

$P_k^{\$e\_imp} \cdot e_k^{imp}$ is the variable cost of buying electricity from the power grid [$/yr]

$P_k^{\$e\_\exp} \cdot e_k^{\exp}$ is the variable income for selling back electricity to the power grid [$/yr]

$P_k^{\$f} \cdot \frac{h_k^{chp}}{\eta_{th}^{chp}}$ is the variable cost of operating the micro-CHP unit [$/yr]

$P_k^{\$f} \cdot \frac{h_k^{aux}}{\eta_{th}^{aux}}$ is the variable cost of operating the auxiliary heating unit [$/yr]

$Pen \cdot h_k^{waste}$ is an economic penalization for discarding heat into atmosphere [$/yr]

---

[44] Description : Open source (Mixed-Integer) Linear Programming system
Language : Multi-platform, pure ANSI C / POSIX source code, Lex/Yacc based parsing
Official name : lp_solve (alternatively lpsolve)
Release data : Version 5.1.0.0 dated 1 May 2004
Co-developers : Michel Berkelaar, Kjell Eikland, Peter Notebaert
Licence terms : GNU LGPL (Lesser General Public Licence)
Citation policy : General references as per LGPL
Module specific references as specified therein.

c. Constraint equations.

The operation of the heating and electric systems in a residential dwelling will be restricted according to the technical capabilities of the equipment being used, and the energy loads which need to be in balance all the time. Therefore, there are at least three types of constraints that we need to take into account: energy balancing constraints, and power and heat-related boundaries.

- Power-related constraints:

These restrictions require that in each hour the electric load be balanced (e_k^{load}), taking into account imports (e_k^{imp}) or exports (e_k^{exp}) of power, and the power generated by the small-CHP (e_k^{chp}). At a particular hour, there can be either power imported from the grid or power exported back. It is not possible to have both at the same time:

$$e_k^{imp} - e_k^{\exp} + e_k^{chp} = e_k^{load}$$
$$e_k^{\exp} = Max\left(e_k^{chp} - e_k^{load}, 0\right)$$
$$e_k^{imp} = Max\left(e_k^{load} - e_k^{chp}, 0\right)$$

The micro-CHP we are modeling has the capability to generate three different levels of electric power ($E^{chp2}, E^{chp3}, E^{chp4}$) different from 0kWh$_e$ (E^{chp1}). This is modeled using binary variables (u_k, x_k, y_k, z_k) that can adopt either 0 or 1 for deciding the operational output of the micro-CHP unit for that particular time:

$$u_k + x_k + y_k + z_k = 1$$
$$e_k^{chp1} = u_k \cdot E^{chp1}$$
$$e_k^{chp2} = x_k \cdot E^{chp2}$$
$$e_k^{chp3} = y_k \cdot E^{chp3}$$
$$e_k^{chp4} = z_k \cdot E^{chp4}$$
$$e_k^{chp} = e_k^{chp1} + e_k^{chp2} + e_k^{chp3} + e_k^{chp4}$$

- Heat-related constraints:

The model requires in each hour the heat load (h_k^{load}) be in balance with respect to the heat produced by the micro-CHP unit (h_k^{chp}), the boiler (h_k^{aux}), and the additional heat that needs to be stored or released for the following hour. In this formulation it is possible to have the micro-CHP unit producing more heat than the load, which will allow having excess heat (h_k^{waste}) at some hours that will be released into the atmosphere.

The heat and power outputs of the micro-CHP (h_k^{chp}, e_k^{chp}) will be related by the HPR which is assumed to be constant for the different engine speeds. This relationship says that for each 1 kWe of power, the micro-CHP will generate 2.7 kWth of heat (as the HPR used is about 2.7):

$$h_k^{chp} + h_k^{aux} - h_k^{waste} = h_k^{in}$$

$$h_k^{chp} = HPR \cdot e_k^{chp}$$

$$where$$

$$HPR = \frac{H^{chp2}}{E^{chp2}} = \frac{H^{chp3}}{E^{chp3}} = \frac{H^{chp4}}{E^{chp4}}$$

Finally, we have included in the model a *dynamic equation* that represents the stored heat conditions in the tank. The stored heat in the next hour will depend on the incoming heat (h_k^{in}) from the micro-CHP and boiler units, the stored heat (h_k^{tank}) and the heat released to meet load at a particular hour:

$$h_{k+1}^{tank} = h_k^{tank} + h_k^{in} - h_k^{load}$$

- Lower and upper bounds:

These limits will be given by the auxiliary boiler and hot water tank (H_{max}^{tank}) maximum heat capacities. In addition, for the boiler we defined a semi-continuous variable (h_k^{aux}) which will take continuous values between a defined minimum (H_{min}^{aux}) and maximum (H_{max}^{aux}), or 0 in the case it is a better result.

$$H_{min}^{aux} \leq h_k^{aux} \leq H_{max}^{aux} \text{ or } h_k^{aux} = 0$$

$$h_k^{tank} \leq H_{max}^{tank}$$

Finally, we defined non-negative decision variables:

$$e_k^{imp}, e_k^{exp}, h_k^{aux}, h_k^{waste}, h_k^{tank} >= 0$$

$$u_k, x_k, y_k, z_k >= 0$$

d. Technical parameters.

As we have explained, there is a variety of micro-CHP technologies. However, as a starting point of our formulations, we took the key parameters of the gas-fired internal combustion engine Ecopower MicroCHP by Marathon Engine Systems. We chose this technology because it has different engine speeds which allow the micro-CHP to produce three discrete power output levels. This attribute gives us the flexibility to go beyond an on/off operation based on a unique power output.

The three possible discrete electrical outputs of the micro-CHP are:

$$E^{chp1} = 0.00kWe$$

$$E^{chp2} = 1.37kWe$$

$$E^{chp3} = 2.37kWe$$

$$E^{chp4} = 4.70kWe$$

The ICE-based micro-CHP has a heat-to-power ratio of about 2.7 ($HPR = 2.7$). Therefore, the possible discrete heat outputs are:

$$H^{chp1} = 0.00kWth$$

$$H^{chp2} = 3.7kWth$$

$$H^{chp3} = 6.4kWth$$

$$H^{chp4} = 12.5kWth$$

The efficiency values for the micro-CHP unit (electric and heat efficiencies) and the auxiliary heating equipment (thermal efficiency) are:

$$\eta_e^{chp} = 24.4\%, \eta_{th}^{chp} = 66.8\%$$

$$\eta_{th}^{aux} = 95\%$$

We note that $\frac{\eta_{th}^{chp}}{\eta_e^{chp}} = 2.7$, and in "Appendix A.4. Micro-CHP efficiency and HPR" we explain the relationship between the efficiency values and the HPR of the micro-CHP.

The heat capacity values for the boiler and hot water tank are:

$$H_{min}^{aux} = 0kWth$$

$$H_{max}^{aux} = 25kWth$$

$$H^{tank} = 5kWh \ for \ a \ 40 \ gal \ tank$$

3.1.5. Model Solution via dynamic programming

For solving the decentralized optimization problem, we used dynamic programming (DP). For this purpose, we identified state and control variables, and the dynamics of the problem. In addition, each hour of the year was defined as one stage.

a. Time horizon.

The model will optimize costs over a time horizon of 1 year, where each stage k will be defined as each hour of the year. Thus, $k = 1,..., \mathrm{N}$ with $N = 8760$ hours[45].

b. State variable.

We chose stored heat in the buffer tank to be the state variable at stage k. For each stage, we quantized the state variable in 20 uniform increments. Thus, in the case where the capacity of the tank was 5kWh, the increment Δh_k^{tank} was 0.250kWh.

$State \ variable \ \ h_k^{tank}$, with aux

In the case of $H_{max}^{tank} = 5kWh$, $H_k = \{0, 0.250, 0.500, 0.750, ..., 5\}$ is the set of admissible states for stage k.

[45] In Chapter 5 the formulation is changed to a 24-hour period, optimizing for every days of the year being studied.

c. Control variable.

In the model, the control variable is a vector comprised by are electric power imported from the grid, power exported back to the grid, power and heat produced by the micro-CHP unit, heat from boiler and excess heat beyond heat demand at stage k.

$Decision\ variables \quad x_k = \left(e_k^{imp}, e_k^{\exp}, e_k^{chp}, h_k^{aux}, h_k^{waste}\right)$, with variables subject to the power and heat-related constraints explained above.

d. Stage cost.

At each stage k, the energy variable costs will be given by:

$$g_k(x_k, h_k^{\tan k}) = \left(P_k^{\$e\_imp} \cdot e_k^{imp} - P_k^{\$e\_\exp} \cdot e_k^{\exp} + P_k^{\$f} \cdot \frac{h_k^{chp}}{\eta_{th}^{chp}} + P_k^{\$f} \cdot \frac{h_k^{aux}}{\eta_{th}^{aux}} + Pen \cdot h_k^{waste}\right)$$

where the total energy variable cost for one year time horizon is:

$$VC = \sum_{k=1}^{N=8760} g_k(x_k, h_k^{\tan k})$$

e. Dynamics

The system equation describes the amount of heat that needs to charge or discharge from one hour to next hour. We initialize the problem assuming that the stored heat in the tank is 0kWh in the last stage. Also, we required the stored heat in the tank to be 0kWh for the initial stage.

$h_{k+1}^{\tan k} = h_k^{\tan k} + h_k^{in} - h_k^{load}$, k=1,2,...,N

$$h_{N+1}^{\tan k} = 0$$

$$h_1^{\tan k} = 0$$

f. Recursion

The DP algorithm will be given by the following iterative relation:

$$J_{N+1}(h_{N+1}^{\tan k}) = 0$$

$J_k(h_k^{\tan k}) = \underset{x_k \in X_k}{Min} \left\{ g_k(x_k, h_k^{\tan k}) + J_{k+1}(h_k^{\tan k} + h_k^{in} - h_k^{load}) \right\}$, k=1,2,...,N=8760

where X_k is the set of admissible decisions that depends on the constraints summarized below:

$$X_k =$$
$$e_k^{imp} - e_k^{\exp} + e_k^{chp} = e_k^{load}$$
$$e_k^{\exp} = Max\left(e_k^{chp} - e_k^{load}, 0\right)$$
$$e_k^{imp} = Max\left(e_k^{load} - e_k^{chp}, 0\right)$$
$$where,$$
$$e_k^{chp} = e_k^{chp\_\mathrm{mod}1} + e_k^{chp\_\mathrm{mod}2} + e_k^{chp\_\mathrm{mod}3} + e_k^{chp\_\mathrm{mod}4}$$
$$e_k^{chp\_\mathrm{mod}1} = u_k \cdot E^{chp\_\mathrm{mod}1}$$
$$e_k^{chp\_\mathrm{mod}2} = x_k \cdot E^{chp\_\mathrm{mod}2}$$
$$e_k^{chp\_\mathrm{mod}3} = y_k \cdot E^{chp\_\mathrm{mod}3}$$
$$e_k^{chp\_\mathrm{mod}4} = z_k \cdot E^{chp\_\mathrm{mod}4}$$
$$u_k + x_k + y_k + z_k = 1$$

$$h_k^{chp} + h_k^{aux} - h_k^{waste} = h_k^{in}$$
$$h_k^{chp} = HPR \cdot e_k^{chp}$$
$$where$$
$$HPR = \frac{H^{chp\_\mathrm{mod}2}}{E^{chp\_\mathrm{mod}2}} = \frac{H^{chp\_\mathrm{mod}3}}{E^{chp\_\mathrm{mod}3}} = \frac{H^{chp\_\mathrm{mod}4}}{E^{chp\_\mathrm{mod}4}}$$

$$H_{\min}^{aux} \le h_k^{aux} \le H_{\max}^{aux} \text{ or } h_0^{aux} = 0$$
$$h_k^{tank} \le H^{tank}$$

$$e_k^{imp}, e_k^{\exp}, h_k^{aux}, h_k^{waste}, h_k^{\tan k} >= 0$$
$$u_k, x_k, y_k, z_k >= 0$$

For the last stage N and for a particular admissible tank level h_N^{tank}, we compute:

$$J_N(h_N^{tank}) = \underset{x_N \in X_N}{Min} \left\{ g_N(x_N, h_N^{tank}) \right\}$$

subject to:

$$h_N^{in} = h_{N+1}^{tank} - h_N^{tank} + h_N^{load} \text{ with } h_{N+1}^{tank} = 0$$
$$X_N$$

Then, the optimization result will be given by decision variables $x_N(h_N^{\tan k}) = \left(e_N^{imp}, e_N^{\exp}, e_N^{chp}, h_N^{aux}, h_N^{waste}\right)$ according to the minimum cost $J_N(h_N^{\tan k})$ for that stage N and particular tank level h_N^{tank}.

These calculations are repeated for all admissible states, i.e. tank level h_N^{tank}, at stage k=N.

For the next stage N-1 and for a particular admissible state, we repeat the sub-optimization problem knowing $J_N(h_N^{tank})$ and h_N^{tank}. Thus, we compute

$$J_{N-1}(h_{N-1}^{tank}) = Min_{x_{N-1} \in X_{N-1}} \left\{ g_{N-1}(x_{N-1}, h_{N-1}^{tank}) + J_N(h_N^{tank}) \right\}$$

subject to

$$h_N^{in} = h_{N+1}^{tank} - h_N^{tank} + h_N^{load}$$

$$X_N$$

This minimization problem is repeated for all admissible states, i.e. tank level h_N^{tank}, at stage k=N-1.

The iterative process is done until we reach the initial stage k=1, where we have computed $J_1(h_1^{tank})$ and $x_1(h_1^{\tan k}) = \left(e_1^{imp}, e_1^{\exp}, e_1^{chp}, h_1^{aux}, h_1^{waste}\right)$ for every admissible state h_1^{tank}.

g. Dynamic programming flow chart[46].

The Figure 3.6 shows a flow chart that describes the dynamic programming solution adopted for solving the MILP problem(78).

[46] Based on "Principles of dynamic programming", Larson, Robert E.; Casti, John L. (1978). Marcel Dekker, INC. New York .

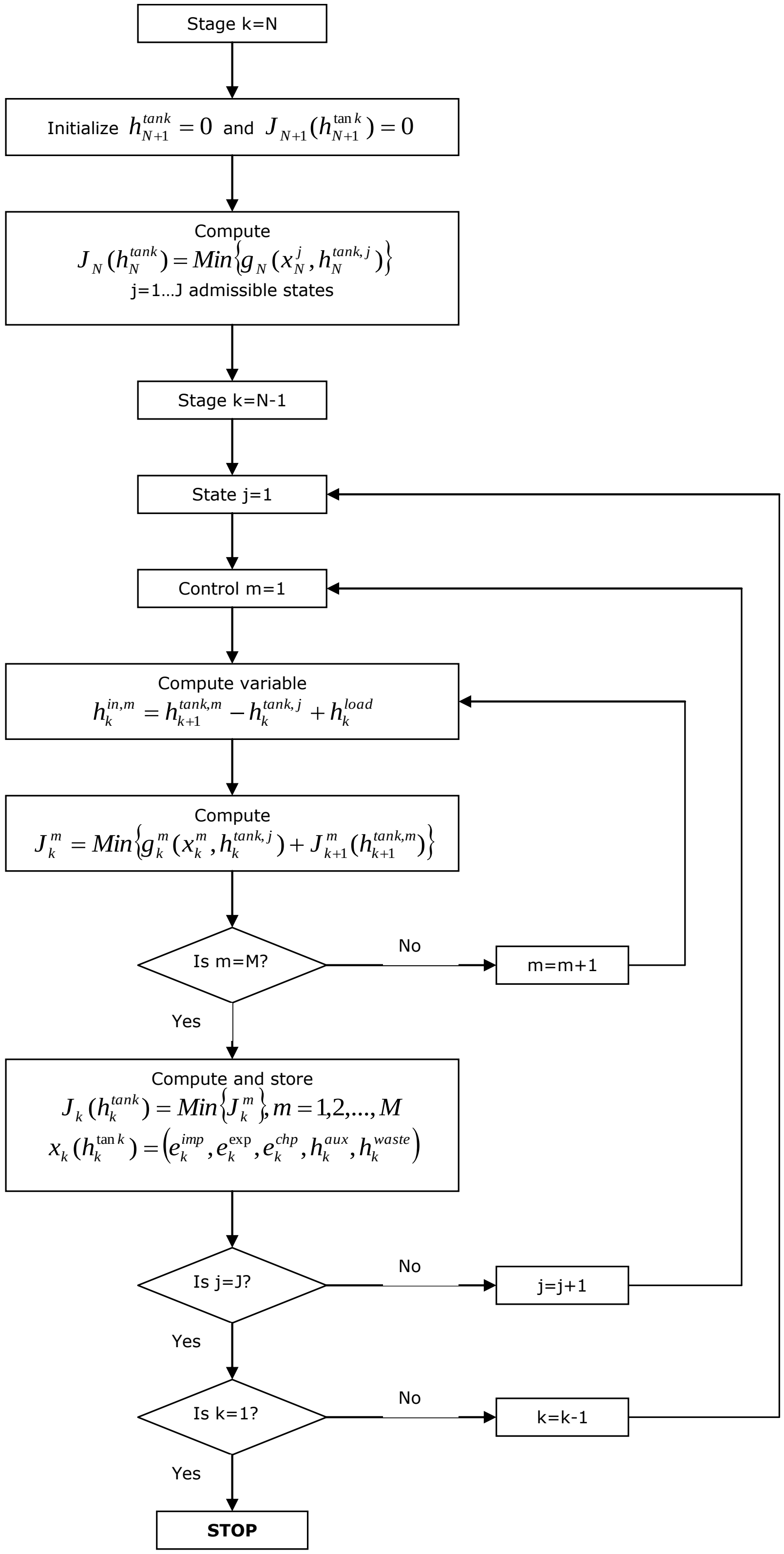

Figure 3.1.4: Dynamic programming flow chart

h. Optimum cost and decision policy.

At the end of this iterative process, we will have that the minimum energy variable cost for the entire one year time horizon will be given by:

$$VC^* = J_1(h_1^{\tan k})$$

However, the Dynamic Programming solution to the problem is a collection of $J_k(h_k^{tank})$ and $x_k(h_k^{\tan k}) = \left(e_k^{imp}, e_k^{\exp}, e_k^{chp}, h_k^{aux}, h_k^{waste}\right)$ for every admissible state h_k^{tank} for k=1,…,N. Thus, we need to recover the optimum sequence of decisions starting from $x_1(h_1^{\tan k})$ assuming $h_1^{\tan k} = 0$ as initial condition.

The optimum decision for stage k=1 will be $x_1(h_1^{\tan k})$ and $J_1(h_1^{tank})$ with $h_1^{\tan k} = 0$.

The optimum decision for stage k=2 will be $x_2(h_2^{\tan k})$ and $J_2(h_2^{tank})$ with $h_2^{\tan k} = h_1^{\tan k} + h_1^{in} - h_1^{load}$, where $h_1^{\tan k} = 0$ and h_1^{in} comes from knowing $x_1(h_1^{\tan k})$.

The recovery process continues until we reach the last stage k=N, where we will have obtained the optimal decision policy for the original problem given by

$$\pi^* = \left\{x_1(h_1^{\tan k})^*, \ldots, x_{8760}(h_{8760}^{\tan k})^*\right\} \text{ and } J_1(h_1^{tank*})$$

3.1.6. Major modeling assumptions

Finally we need to explain the key assumptions we have adopted for constructing the stringent-control and intelligent-control decentralized models.

On the technology side, we have:

- The micro-CHP has a discrete operation with three possible outputs. The heat-to-power ratio (HPR) was held constant for the different engine speeds.
- The micro-CHP electric and thermal efficiencies are kept constant for the different levels of operation.
- Micro-CHP start-up and shut-down times were not modeled as they are below 30min. The models are based on one hour time step.
- The auxiliary boiler is assumed to be high efficient and continuously modulating. It has enough capacity to cover peak heat demands.
- The hot water buffer tank is highly insulated, so the model does not consider losses.
- Excess heat beyond thermal demand is allowed in the formulation. Thus, if the heat production is greater than the heat load, the excess will be discarded into the atmosphere.

In addition, as the micro-CHP is connected to the power and natural gas grid, we assumed:

- The micro-CHP operates in parallel to electric grid and the unit is able to export power to grid in case of surplus or import power from grid for supplemental purposes. We did not constrain the capacity of the electric wires for electricity export.
- There is plenty of natural gas for supplying heating requirements, and we assumed no delivery restrictions as well.

Regarding energy loads and prices, we assumed that end-users are capable of knowing in advance their electric and heat demands, as well as electricity and fuel prices on an hourly basis.

For the energy variable cost we used a linear function based on electricity and the amount of fuel consumption. For the purpose of cost minimization we assumed the export electricity price to be always lower than the import electricity price.

Finally, as we mention earlier, householders will be required to have some kind of smart communication system for data measuring and processing. This will make possible for them to have hourly energy and price information beforehand. In addition, for the least-cost optimization strategy, the micro-CHP system will need to have an intelligent control system that will integrate the energy system information and base its operational decisions on that.

3.2. Preliminary simulation results

In this section, we try to understand the local effects, i.e. at the household level, of having a micro-CHP system instead of a conventional electric & heating system. As we previously explained, a decentralized operation of a micro-CHP will depend upon the decision that a household makes which will rely on factors ranging from heat comfort-level to more sophisticated ones such as reduction of energy variable costs or environmental concerns. Depending on the information and communication infrastructure available to residential customers, this decentralized control could range from a stringent-strategy to an intelligent-strategy. In the first case, the household programs the micro-CHP to run based only on the heat load or power load at some specific moment in time. In the latter case, the residential customer will base his decision not only on the energy load, but also on the energy prices. Thus, through on-site generation, users will be able to respond to the economic signals provided by the energy prices.

For the purpose of measuring the micro-CHP impact locally, we will work with four cases: a reference case, an intelligent-control case, and two stringent-control cases. The *reference case* is defined as such a system where households do not have a micro-CHP unit, hence relying on conventional heating systems and on power grid connection for meeting thermal and electric needs respectively. The intelligent-control case (*chp_tank case*) is defined as a price-responsive system with a grid-connected micro-CHP unit, auxiliary heating equipments, and a buffer tank for hot water storage. Finally, we defined a heat-lead and an electricity-led non-intelligent control cases (*heat-led case* and *elec-led case*) where the micro-CHP will follow the local thermal and power loads respectively, independent of price conditions.

We will compare the potential benefits and costs of each case based on five performance metrics: energy costs, energy efficiency, CO2 emissions, net power and net heat. *Energy costs* are defined as total annual energy variable costs, including costs for electric power and fuel purchases and revenues for power sold back to the grid. *Energy efficiency* is defined as the ratio of usable energy to the total fuel consumption by the retail customer. This definition takes into account not only energy generated locally but also the supplemental electricity bought to the grid. *CO2 emissions* are quantified based on on-site fuel consumption (for heating and power), fuel related to the imports of power from the grid, and avoided emissions by the bulk system due to exports of power by end-consumer. Finally net power and net heat are calculated based on total micro-CHP electric and heat generation after discounting excess of on-site generation (i.e. power export and excess heat respectively).

Before showing the results from simulation, we will briefly recall the key inputs used in the model[47]:

a. Technical assumptions:
    - Micro-CHP is based on a natural gas-fired ICE, with a discrete output range of 1.37kW, 2.37kW and 4.7kW.
    - Micro-CHP heat-to-power ratio is about 2.7, with electric and thermal efficiencies of 24.4% and 66.8% respectively.
    - Boiler is continuously modulating and high efficient, with a capacity of $25kWh_{th}$ and a thermal efficiency of 95%.
    - Buffer tank for hot-water storage has a heating capacity of with $5kWh_{th.}$
b. Energy load and prices assumptions:
    - Hourly energy demands for a 2,500 ft2 model-house, with air conditioner, and located in Boston (see Figure 3.1.2).
    - Monthly energy prices according to utility historical gas and electricity retail rates in the area of Boston. Feed-in tariff assumed to be 1¢/kWh lower than electricity retail rate (Figure 3.1.3).

3.2.1. Results for medium heat-to-power ratio technology

Results show that a micro-CHP-based system *may* bring benefits to a residential customer when compared to a conventional heating/electric system. For the particular conditions adopted in the model, aggregated annual results show:

- Energy cost savings ranging from -18% up to 17%.
- Energy efficiency improvements ranging from -2% up to 21%.
- CO_2 emissions reductions ranging from -9% up to 22%.

[47] Refer to previous section for details on inputs and parameters.

In addition, on-site generation is able to meet between 30% and 100% of the annual electric demand, and between 75% and almost 100% of the annual heat demand.

We recognize that results will depend on the control strategy applied to the micro-CHP unit. In the case of a non-intelligent strategy, negative outputs can come up if the technology is not suitable for the particular load. Below we will show that if the technology is different, a stringent-control may provide benefits instead of costs.

In the following section we will explain in detail the results for each metric. Also, besides looking at aggregated annual results we will look at monthly outputs and recognize seasonal variations.

3.2.1.1. Energy costs

Operational variable costs are function of fuel consumption for heating purposes and on-site power generation ($fuel_{aux}$, $fuel_{chp}$), electricity purchases from the grid (e_{imp}), and eventually revenues generated by electricity sold back to the utility (e_{exp}).

$$Energy\ cost = Pse_{imp} \cdot e_{imp} - Pse_{exp} \cdot e_{\exp} + Psf \cdot \left(fuel_{chp} + fuel_{aux} \right)$$

Where $Pse_{imp}, Pse_{exp}, Psf$ are energy prices ($/kWh) for imported and exported power, and fuel purchase respectively.

In Table 3.2-1 annual results show that a residential customer with a micro-CHP system combined with a buffer tank would save about 17% with respect to the reference case. However, we also see that depending on the control strategy the customer could experience additional costs, as in the case of electricity-led control. In addition, the least-cost operation and heat-led operation show similar savings.

Cases	*Energy cost* [$/yr]	*Savings* [%]
reference	3,181	0%
chp_tank	2,632	17%
heat-led	2,711	15%
elec-led	3,765	-18%

Table 3.2-1: Annual energy costs [$/yr]

In Table 3.2-2 we see the positive contributions coming mostly from the winter months and especially for the least-cost and heat-led strategies. The power purchases from the utility company decrease considerable as the micro-CHP unit generates the required heat and power requirements. As the heat component during winter is high[48], the micro-CHP operates most of the hours and it produces most of the heat and power. In summer, because of the use of air conditioner, the electricity component increases. The micro-CHP produces most of the heat, but it is not enough to cover the total electricity needs, requiring an increase of the power from the grid.

[48] Monthly average HPR of the load is close or above 5 during January, February and December, while monthly average HPR of the load from May to September is below 1.

Month	Energy costs						
	reference [$/mo]	chp_tank [$/mo]	savings [%]	heat-lead [$/mo]	savings [%]	elec-led [$/mo]	savings [%]
January	484	357	26%	361	25%	404	17%
February	386	277	28%	281	27%	319	17%
March	344	275	20%	279	19%	323	6%
April	223	194	13%	199	11%	281	-26%
May	155	140	10%	148	5%	239	-55%
June	180	168	6%	177	1%	319	-78%
July	219	207	6%	216	1%	390	-78%
August	212	199	6%	209	1%	362	-71%
September	155	144	7%	152	2%	267	-73%
October	155	137	12%	145	7%	223	-44%
November	278	229	18%	233	16%	284	-2%
December	390	306	22%	310	21%	352	10%
Total	**3,181**	**2,632**	**17%**	**2,711**	**15%**	**3,765**	**-18%**

Table 3.2-2: Monthly energy costs [$/month]

We also see a poor economic performance of the stringent electricity-led strategy. As the micro-CHP follows the power load, the heat generated is a by-product that not necessarily coincides with the heat load. Especially in summer, most of heat is thrown away under this control strategy resulting in a much more expensive operation.

3.2.1.2. Energy efficiency

Energy efficiency is defined as the ratio of usable energy to the total fuel consumption by the residential customer. This definition takes into account not only the energy generated locally by the micro-CHP, but also the supplemental electricity bought to the grid and the related fuel consumption.

In our local system, the energy components come from of the electricity and heat generated the micro-CHP (e_{chp}, h_{chp}), the heat generated by auxiliary heating equipments (h_{aux}) after conversion losses, and any excess heat (h_{waste}) not used by the dwelling that needs to be removed. Then, fuel consumption considers that amount of fuel required for operating the micro-CHP ($fuel_{chp}$), and that fuel used for auxiliary heating equipments ($fuel_{aux}$).

This definition of energy efficiency also considers the amount of electricity imported (e_{imp}) from the grid, which it is used for supplemental purposes. Thus, we need to estimate the amount of fuel ($fuel_{eimp}$) required by the bulk power system to deliver that amount of power at the retail level, which largely depends on the regional energy portfolio. The large power plants operated to provide such electricity have varied technologies, use diverse fuel sources, and have different fuel conversion efficiency rates. Normally, the power produced in these plants is transported and delivered to final customers through the transmission and distribution system, where losses can be significant. Therefore, the fuel consumption estimation needs to take into the electric energy mix, technology efficiencies, and transmission and distributions losses.

Energy efficiency is calculated as:

$$Energy\ efficiency = \frac{\left(e_{chp} + h_{chp} + h_{aux} - h_{waste}\right) + e_{imp}}{\left(fuel_{chp} + fuel_{aux}\right) + fuel_{eimp}}$$

Where,

$$fuel_{chp} = \frac{h_{chp}}{n_{th}^{chp}}$$

$$fuel_{aux} = \frac{h_{aux}}{n_{th}^{aux}}$$

$$fuel_{eimp} = e_{imp} \cdot \frac{1}{n_{avg}} \cdot \frac{1}{(1 - loss_{dxtx})}$$

$$\frac{1}{n_{avg}} = \left(\frac{\%_{NG}}{\eta_{NG}} + \frac{\%_{oil}}{\eta_{oil}} + \frac{\%_{Coal}}{\eta_{Coal}} + \frac{\%_{fossil\ free}}{\eta_{fossil\ free}} \right)$$

For the calculations we assumed a total micro-CHP efficiency of 91.2%[49], electric and thermal efficiencies of 24.4% and 66.8% respectively ($n_{ele}^{chp}, n_{th}^{chp}$), and an auxiliary heating system efficiency of 95% (n_{th}^{aux}). The annual average delivery loss in the system was assumed to be 9.5%[50] ($loss_{txdx}$). Finally, we assumed an aggregated electrical efficiency for the entire energy portfolio of 33%[51] (n_{avg}), where fossil fuel sources account for 64% and 36% for fossil-free sources.

In Table 3.2-3 annual results show that, with the incorporation of a micro-CHP system and depending on the control strategy, efficiency could improve up to 21% with respect to the reference case. This increment is the result displacing energy produced at lower efficiency with energy generated by the micro-CHP more efficiently. In both cases, intelligent and heat-led control, the excess heat that is not used by the consumer is minimal.

Cases	***Energy efficiency**** [%/yr]	***Increment*** [%]
reference	57%	0%
chp_tank	69%	21%
heat-led	66%	16%
elec-led	56%	-2%

Table 3.2-3: Annual energy efficiency [$/yr]

However, we also see that the stringent electricity-led strategy will not bring any improvements with respect to the reference case. As shown in Table 3.2-4 below during winter the energy efficiency is high, contrary to what happens during summer where the efficiency worsens. In summer, electric demand is higher than heat load

[49] Value is in accordance to the value provided for the manufacturer for the particular technology we are using in the model.
[50] US-wide transmission and distribution losses (1).
[51] Electricity portfolio was taken from NSTAR energy label for March 2005, where natural gas-based energy sources was 35% ($\%_{NG}$), coal-based energy sources was 15% ($\%_{coal}$), oil-based energy sources was 14% ($\%_{oil}$), and fossil-free based sources was 36% ($\%_{fossil\ free}$). Then, we assumed average electric efficiencies for gas-fired turbines of 34%, coal-fired power plants of 37%, oil-fired plants of 38%, and a combined electric.

and as the micro-CHP follows the electrical load, it also produces plenty of excess heat (beyond heat requirements and tank capacity).

Month	Energy efficiency						
	reference [%/mo]	*chp_tank* [%/mo]	*increment* [%]	*heat-lead* [%/mo]	*increment* [%]	*elec-led* [%/mo]	*increment* [%]
January	72%	90%	24%	88%	21%	90%	25%
February	70%	88%	25%	86%	22%	87%	23%
March	67%	84%	27%	82%	23%	79%	18%
April	58%	72%	24%	68%	18%	59%	2%
May	45%	51%	14%	47%	5%	39%	-13%
June	40%	43%	10%	40%	2%	33%	-16%
July	38%	41%	8%	39%	2%	32%	-17%
August	39%	42%	9%	39%	2%	32%	-17%
September	41%	45%	10%	41%	2%	34%	-16%
October	48%	56%	17%	51%	7%	43%	-11%
November	64%	82%	28%	79%	23%	73%	13%
December	70%	87%	25%	85%	22%	84%	21%
Total	**57%**	**69%**	**21%**	**66%**	**16%**	**56%**	**-2%**

Table 3.2-4: Monthly energy efficiency [%/month].

Finally is worth note that in all cases there is an energy efficiency improvement during winter as the load heat component is greater than the power component.

3.2.1.3. Carbon dioxide emissions

When meeting energy requirements at the household level, the emissions of carbon dioxide will relate to the fuel consumed for supplying the loads. Therefore, the sources of emissions will be mainly two: on-site and central generation. In the first case, fuel is purchased to operate the heating system and the micro-CHP unit if installed, which we assumed use natural gas. In the second case, the electricity provided by the utility company at the retail level comes from several power plants in the bulk power system. These plants form a particular energy portfolio, where their generating technologies are varied, with different heat rates and diverse primary energy sources. Also, these plants are located far from the final destination, requiring transmission and distribution systems for delivering the power to final consumers. These characteristics make challenging to accurately calculate the emissions associated to electricity provision. Consequently, we make a rough estimation of CO_2 emissions assuming the energy portfolio that we found in the New England System[52].

We calculated three CO_2 emission-related values:

1. *From on-site fuel*. Emissions are proportional to the amount of purchases of fuel for micro-CHP ($fuel_{chp}$) and auxiliary heating equipment ($fuel_{aux}$) operation

   $$CO_2\ fuel = (fuel_{chp} + fuel_{aux}) \times CO_2\ factor^{NG}$$

   Where NG CO_2 emission factor is 0.0531 [Metric ton/MMBtu] ($CO_2\ factor^{NG}$)

[52] Refer to footnote #51 for energy portfolio.

2. *From imports of electricity*. As explained above, emissions depend on the energy portfolio where the electric power is coming from. As emissions are proportional to the fuel used by the portfolio, we need to estimate the fuel used by the bulk system for providing such electricity. Thus, we use the percentage of energy sources in the portfolio, power plants' average electric efficiencies, and average delivery losses

$$CO_2\ imp = e_{imp} \cdot \frac{1}{(1-loss_{txdx})} \cdot \left(\frac{\%_{NG}}{\eta_{NG}} \cdot CO_{2\ factor}^{\ NG} + \frac{\%_{oil}}{\eta_{oil}} \cdot CO_{2\ factor}^{\ oil} + \frac{\%_{Coal}}{\eta_{Coal}} \cdot CO_{2\ factor}^{\ Cosl} \right)$$

Where CO_2 emission factors for oil & coal are 0.0788 and 0.1021 [Metric ton/ MMBtu] respectively ($CO_2\ factor^{\ oil}, CO_2\ factor^{\ coal}$)[53]

3. *From exports of electricity*. Emissions from exports of electricity generated in excess by the micro-CHP machine are regarded as "avoided" emissions. The bulk system will emit less CO_2 as a consequence of on-site power being exported instead of central power that the utility company would have been required to supply. This value is calculated the same way as emissions from imports, but taking into account the amount of electricity sold-back to the grid ($e_{\exp}$) and with negative sign.

$$CO_2\ \exp = -e_{\exp} \cdot \frac{1}{(1-loss_{txdx})} \cdot \left(\frac{\%_{NG}}{\eta_{NG}} \cdot CO_{2\ factor}^{\ NG} + \frac{\%_{oil}}{\eta_{oil}} \cdot CO_{2\ factor}^{\ oil} + \frac{\%_{Coal}}{\eta_{Coal}} \cdot CO_{2\ factor}^{\ Cosl} \right)$$

Using these three values, we calculated net carbon dioxide emissions in metric ton per year as:

$$Net\ CO_2\ emissions = CO_2\ fuel + CO_2 import + CO_2 export$$

Table 3.2-5 shows that, depending on the control configuration, a dwelling with a micro-CHP system can reduce CO2 emissions by up to 22% annually. We see that on-site fuel consumption will increase as micro-CHP supplies heat and power (i.e. more energy). Thus, emissions from fuel increase with respect to the reference. We note an emissions reduction from imported power as the volume acquired from the utility decreases. However, this component is highly sensitive to the energy portfolio and how clean it is relative to the fuel used by the micro-CHP unit. Under the electricity-led strategy CO_2 emissions increase as too much fuel is used locally when following the electrical load.

	CO2 emissions				
Cases	***Total*** [metric ton/yr]	***Reductions*** [%]	***from fuel*** [metric ton/yr]	***from import*** [metric ton/yr]	***from export*** [metric ton/yr]
reference	9.99		4.72	5.28	-
chp_tank	7.82	22%	6.65	2.97	(1.80)
heat-led	8.13	19%	6.42	3.57	(1.87)
elec-led	10.94	-9%	13.46	-	(2.53)

Table 3.2-5: Net CO2 emissions [metric ton/yr]

[53] Refer to footnote #51 for efficiency and energy mix values.

3.2.1.4. *Micro-CHP net electric power and heat*

In this section, we are interested in comparing the operational performance of the micro-CHP system under different control-strategies having a sense of how much the customer relies on this technology for meeting its energy needs.

A residential dwelling with a micro-CHP unit will produce heat and power, which could exceed the local energy requirements. Recall that the power supplied by the micro-CHP unit can adopt three possible discrete values[54]. On one hand, if the micro-CHP power output is less than the hourly electric demand, then electric power is imported from the grid; and if the micro-CHP heat output is less than the hourly heat demand, then heat is supplemented by auxiliary heating systems. On the other hand, if the micro-CHP power output is greater than the hourly electric demand, then an excess power is generated which could be diverted back to the grid; and if the micro-CHP heat output is greater than the hourly heat demand, then an excess heat produced which could be stored in a buffer tank but also part could be discarded to the atmosphere.

Having in mid the above, net power & net heat were calculated based on the micro-CHP production (e_{chp}, h_{chp}) after discounting the excesses of energy ($e_{\exp}, h_{waste}$) as follows: $Chp\ net\ power = e_{chp} - e_{\exp}$, and $Chp\ net\ heat = h_{chp} - h_{waste}$

In terms of electric power Table 3.2-6 shows us that, depending on the control strategy, the net power generated by the micro-CHP meets between 32% and 100% of the total annual electric demand. In Figure 3.2.1 we can see the annual amount of power being exported back to the grid. Finally, we calculated the capacity factor of the micro-CHP[55] which will range between around 20% and 40%. Looking at seasonal variations, during winter the micro-CHP supplies over 70% of the load, whereas in summer the contribution is much lower. However, under the electricity-led

Cases	*Electrical load* [kwh/yr]	*Import power* [kwh/yr]	% load [%]	*Chp net power** [kwh/yr]	% load [%]
reference	11,189	11,189	100%	-	0%
chp_tank	11,189	6,307	56%	4,882	44%
heat-led	11,189	7,579	68%	3,610	32%
elec-led	11,189	-	0%	11,189	100%

Table 3.2-6 Micro-chp net electric power

(Capacity factor is 21%, 18%, and 40% for each case respectively)

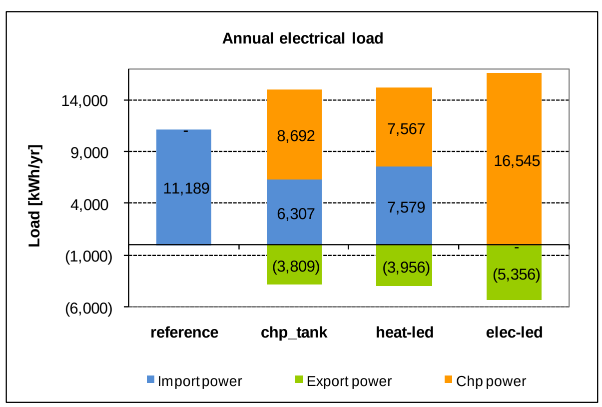

Figure 3.2.1: Annual power imports, micro-chp electric power and electricity surplus exported back the grid

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[54] Refer to previous section for details.

[55] Capacity factor is defined as the ratio between the current electric energy output and the maximum energy based on 4.7kW capacity.

strategy the micro-CHP supplies the total load all year-round.

In terms of heat we can see in Table 3.2-7 and Figure 3.2.2 that the net annual contribution of the micro-CHP unit to the heating requirements will be over 75% depending on the control strategy. A non-intelligent control like the electricity-led strategy will result in a poor performance of the machine, where more than half of the heat generated by the micro-CHP (about 60%) is wasted. Even worse in this case is that the non-coincidental characteristic of the heat and power loads will result in requiring lots of supplemental heat by the auxiliary boiler.

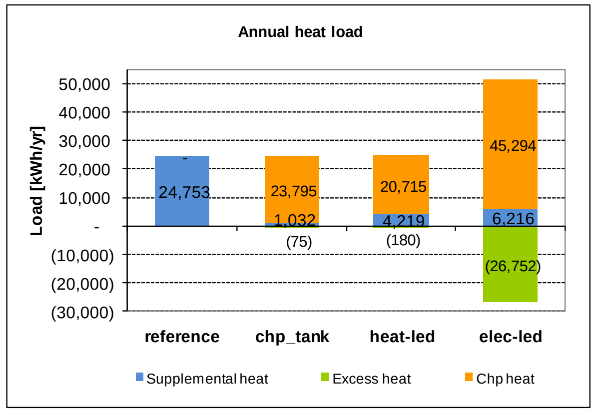

Figure 3.2.2: Annual supplemental heat, micro-chp heat and excess heat

Cases	Heat load [kwh/yr]	Supplemental heat [kwh/yr]	% load [%]	Chp net heat* [kwh/yr]	% load [%]
reference	24,753	24,753	100%	-	0%
chp_tank	24,753	1,032	4%	23,721	96%
heat-led	24,753	4,219	17%	20,534	83%
elec-led	24,753	6,216	25%	18,542	75%

Table 3.2-7: micro-CHP net heat power [kWh/yr]

3.2.2. Results for low heat-to-power ratio technology

Up to now we have seen results when the micro-CHP is based on an internal combustion engine with a medium heat-to-power ratio of about 2.7. However, results are sensitive to several parameters, being the technology one of them. *If the technology is different and more suitable to the local load characteristics*, a non-intelligent control like the power-led one may also provide benefits instead of costs and the other control strategies may bring better results.

A low HPR, below 1, may be more representative of a fuel cell-based technology[56] with a total efficiency of 80%, electric and thermal efficiencies of 50% and 30% respectively. For these cases, we assumed the same three discrete electrical outputs, i.e. 1.37, 2.37 and 4.7kWe, and the corresponding heat outputs would be 0.82, 1.42 and 2.82kWth. We note that under this assumption, the potential heat that the micro-CHP can generate decreases considerably and we will require using auxiliary heating equipment much more time.

[56] Based on SOFC-based BlueGen (49).

Therefore, if instead of a HPR of 2.7 we use a lower HPR of 0.6, aggregated annual results show:

- Energy cost savings ranging from 23% up to 44%.
- Energy efficiency improvements ranging from 26% up to 43%.
- CO_2 emissions reductions ranging from 33% up to 71%.

In addition, on-site generation is able to meet more than 80% of the annual electric demand, and between 30% and almost 60% of the annual heat demand.

Energy costs are shown in Table 3.2-8. Now we see a larger difference between an optimal versus a stringent heat-led strategy, whereas previously it was not that clear the economic benefits of an intelligent strategy based on a medium HPR machine. Moreover, the other stringent electricity-led strategy will also result in energy cost savings. Here the micro-CHP will operate similarly as in the case with medium HPR but now there is a small amount of waste heat and energy is being used more efficiently.

Cases	Energy cost [$/yr]	Savings [%]
reference	3,181	0%
chp_tank_hpr06	1,791	44%
heat-led_hpr06	2,052	36%
elec-led_hpr06	2,438	23%

Table 3.2-8: Annual energy costs with low HPR

Monthly results in Table 3.2-9 show that, if both stringent strategies are combined for a heat-lead operation during winter and electricity-led operation in summer (see grey rows in table); the net result would be similar to the one obtained under an intelligent-control mode.

Month	Energy costs						
	reference [$/yr]	***chp_tank_hpr06*** [$/yr]	***savings*** [%]	***heat-lead_hpr06*** [$/yr]	***savings*** [%]	***elec-led_hpr06*** [$/yr]	***savings*** [%]
January	484	271	44%	284	41%	405	16%
February	386	180	54%	199	49%	310	20%
March	344	201	41%	218	37%	284	17%
April	223	150	33%	160	28%	181	19%
May	155	74	52%	101	35%	99	36%
June	180	108	40%	131	27%	120	33%
July	219	129	41%	165	25%	146	33%
August	212	110	48%	153	28%	133	37%
September	155	90	42%	109	29%	102	34%
October	155	65	58%	95	39%	97	37%
November	278	169	39%	182	35%	229	18%
December	390	243	38%	256	34%	331	15%
Total	**3,181**	**1,791**	**44%**	**2,052**	**36%**	**2,438**	**23%**

Table 3.2-9: Monthly energy costs

Combining winter heat-led operation & summer power-led operation could result in a more cost-effective operation

In Table 3.2-10 we see the annual energy efficiency for each case. Here it is interesting to note that in all cases there is an improvement of efficiency. However, the most cost-effective case is not the best in terms of efficiency. A low HPR will modify the economic signals that the micro-CHP sees. The machine will prefer to generate at full capacity most of the time to get revenues from export, even if it has excess heat. Under this strategy, there is lots of waste heat that deteriorates the efficiency especially during summer when the heat

Cases	Energy efficiency* [%/yr]	Increment [%]
reference	57%	0%
chp_tank_hpr06	72%	26%
heat-led_hpr06	77%	35%
elec-led_hpr06	81%	43%

Table 3.2-10: Annual energy efficiency with low HPR

component is low. The electricity-led strategy on the other hand has better efficiency values because there is much less waste heat during summer - now the machine produces less heat per unit of electricity[57] (see Figure 3.2.4).

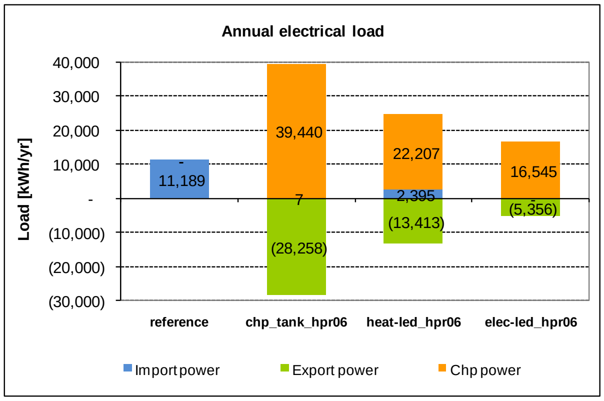

Figure 3.2.4a: Annual power imports, micro-CHP electric power and electricity surplus for low HPR

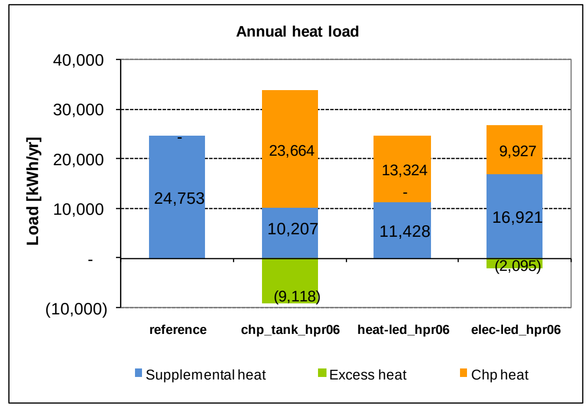

Figure 3.2.4b: Annual supplemental heat, micro-CHP heat and excess heat for low HPR

The fuel efficiency for each case will depend on the means used for converting it to end-use energy. As shown in Table 3.2-11 , fuel used for providing imports of electricity will be converted with 30% efficiency and fuel used by auxiliary boilers will be converted with 95% efficiency.

Cases	***Imp. power*** [kwh/yr]	***Eff.*** [%]	***Chp power*** [kwh/yr]	***Chp heat*** [kwh/yr]	***Exc. heat*** [kwh/yr]	***Chp energy*** [kwh/yr]	***Eff.*** [%]	***Aux. heat*** [kwh/yr]	***Eff.*** [%]	***Total energy*** [kwh/yr]
reference	11,189	30%	-	-	-	-	-	24,753	95%	**35,942**
chp_tank_hpr06	7	30%	39,440	23,664	(9,118)	53,986	68%	10,207	95%	**64,200**
heat-led_hpr06	2,395	30%	22,207	13,324	-	35,532	80%	11,428	95%	**49,355**
elec-led_hpr06	-	30%	16,545	9,927	(2,095)	24,376	74%	16,921	95%	**41,297**

Table 3.2-11: Total energy (heat & electricity) produced and used locally and fuel conversion efficiencies for low HPR

Although the micro-CHP has a total efficiency of 80% for the low HPR case (or 91.2% for the high HPR case) the final efficiency may be lower if the excess heat is discarded. Thus, micro-CHP efficiency will be 68%, 80% and 74% for the intelligent-control, heat-lead and electricity-led cases respectively (before considering the efficiency of auxiliary heating units).

Once we have the amount of energy used and produced on-site, we can estimate the amount of fuel and the total energy efficiency (see Table 3.2-12).

Cases	***Fuel Import*** [kwh/yr]	***Fuel Chp*** [kwh/yr]	***Fuel Aux*** [kwh/yr]	***Total fuel*** **[kwh/yr]**	***Total efficiency*** **[%/yr]**
reference	37,296	-	26,056	**63,351**	**57%**
chp_tank_hpr06	25	78,879	10,744	**89,648**	**72%**
heat-led_hpr06	7,982	44,415	12,030	**64,427**	**77%**
elec-led_hpr06	-	33,089	17,812	**50,901**	**81%**

Table 3.2-12: Total fuel used locally and total energy efficiencies for low HPR

[57] For the low HPR case, the total micro-CHP efficiency was assumed 80% while the efficiency of the boiler was 95%.

In Figure 3.2.5 we see that for the least-cost case the efficiency is low because of the micro-CHP energy generated at lower efficiency. For the heat-lead case, it is the low efficient import power that worsens the energy efficiency when compared to the electricity-led case.

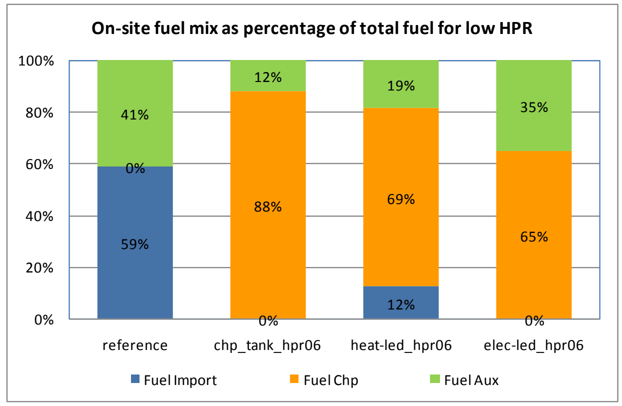

Figure 3.2.5: On-site fuel mix for low HPR

In terms of net power and heat, we see in general that as the HPR decreases the heat capacity of the micro-CHP is not enough to fulfill the total thermal load. As shown in Table 3.2-14 a considerable percentage of heat is supplied by auxiliary heating equipments. Regarding net power we note that under the least-cost strategy, the micro-CHP operates at full capacity almost the entire time as there is an incentive to export electricity back to the grid.

Cases	***Electrical load*** [kwh/yr]	***Import power*** [kwh/yr]	***% load*** [%]	***Chp net power**** [kwh/yr]	***% load*** [%]
reference	11,189	11,189	100%	-	0%
chp_tank_hpr06	11,189	7	0%	11,181	100%
heat-led_hpr06	11,189	2,395	21%	8,794	79%
elec-led_hpr06	11,189	-	0%	11,189	100%

Table 3.2-14: Micro-chp net electric power

Capacity factor is 96%, 54%, and 40% respectively

Cases	***Heat load*** [kwh/yr]	***Supplemental heat*** [kwh/yr]	***% load*** [%]	***Chp net heat**** [kwh/yr]	***% load*** [%]
reference	24,753	24,753	100%	-	0%
chp_tank_hpr06	24,753	10,207	41%	14,546	59%
heat-led_hpr06	24,753	11,428	46%	13,324	54%
elec-led_hpr06	24,753	16,921	68%	7,831	32%

Table 3.2-14: Micro-chp net heat

Regarding CO_2 emissions, the least-cost strategy tries to get the most from the power exports revenues. As we see in Table 3.2-15, the micro-CHP is consuming a large amount of fuel and as the power is fed back to the grid, the bulk system is reducing its emissions for not providing this amount of electricity. Thus, we see that the net CO_2 emissions after discounting the component from export are the least for the intelligent-control strategy. However, we need to point out that these results will depend on the region's energy portfolio, and the CO_2 emissions from import and export will vary according to the energy mix. Also, these calculations do not take into account the fact that micro-CHP are on-site stationary emission sources while large power plants are distant emissions sources.

	CO2 emissions				
Cases	***Total*** [metric ton/yr]	***Reductions*** [%]	***from fuel*** [metric ton/yr]	***from import*** [metric ton/yr]	***from export*** [metric ton/yr]
reference	9.99		4.72	5.28	-
chp_tank_hpr06	2.91	71%	16.23	0.00	(13.33)
heat-led_hpr06	5.02	50%	10.22	1.13	(6.33)
elec-led_hpr06	6.69	33%	9.22	-	(2.53)

Table 3.2-15: Annual CO2 emissions with low HPR

3.2.3. Summary

In this section, we showed that a micro-CHP unit brings benefits in terms of operational costs, energy efficiency and CO2 emissions to individual householders. These positive results - in comparison to what can be achieved with only conventional heating systems - may make micro-CHP technology appealing for potential new customers who seek to buy or upgrade their heating systems.

Results at the residential level showed, in general, CO2 emissions reductions, energy efficiency improvement and energy costs savings, with the most important contributions during winter. However, these benefits vary depending on the micro-CHP control strategy adopted by customers, where both cost-based and heat-led operations have similar results. Moreover, these benefits may disappear if micro-CHPs are poorly operated. It was shown that in a power-led strategy, as the machine follows the consumer's electric load, the produced heat not necessarily coincides with the heat load, leading to excess of heat that worsens the performance of the technology.

Also, these benefits vary depending on the micro-CHP technology, which in this research have been characterized by their heat-to-power ratio. We observe that, for the particular load conditions, lower HPR modifies the response of micro-CHPs to the economic signals. When prices are high, the machine tries to generate at full capacity most of the time with the double purpose of avoiding to buy electricity and to get revenues from surplus of generated electricity. We also note that the operation of the micro-CHP is not the most efficient, as there is an important amount of excess heat during summer that deteriorates the performance of the machine.

Finally, we need to mention that these results depend as well of the micro-CHP size. Results in this and the next section work with a relatively large technology for on-site load requirements, where capital costs have not been considered for the economic calculations. Therefore, from the operational point of view, the machine is very attractive as less supplementary heat and electric power is required. However, as the electric capacity factor is low, the incremental investment costs are difficult to recover with the operational savings within a reasonable period of time. As we will see in Chapters 5 and 6, it is important to work with a micro-CHP size optimally adapted to the residential energy load conditions (for details refer to Appendix C.12. Micro-CHP optimum size analysis for customer class C1 & C2).

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CHAPTER 4

DECENTRALIZED MODEL PERFORMANCE: SENSITIVITY ANALYSES

As we showed in the previous chapter, the household model outputs are sensitive to the inputs and design parameters, as well as the control strategies adopted for operating the micro-CHP unit. The preliminary benefits we found were under a particular set of conditions that in this chapter we revise.

Therefore, the purpose here is to understand how sensitive the results of the model are to variations of some features. In particular, we investigate the operational, economic and environmental impacts of:

- Incorporating a hot water tank to the heating system configuration.
- Having different levels of stored heat in the tank at the end of the simulation period.
- Having varied energy prices, such as retail electricity prices for import of electricity import, and buy-back rates for electricity surplus.
- Changing the micro-CHP technology - characterized by its heat-to-power ratio - to other technology able to produce electricity more efficiently.

The following analyses are performed on the model based on the micro-CHP intelligent strategy. Recall that under this formulation, the micro-CHP unit is able to respond to energy price variations, and the largest positive outcomes are achieved using this control strategy.

4.1. Sensitivity to heat storage tank

A residential heating system can have different configurations that may or not incorporate a hot water storage unit. In the case of a warm-air based system, the micro-CHP unit and an auxiliary furnace generate warm air which is distributed throughout the house using a blower (no storage is available). In the case of a hydronic system, the micro-CHP and an auxiliary boiler generate hot water that is used to meet the dwelling heat load through a heating circuit. In addition, the hot water may be stored in a buffer tank at high temperatures for later use for space heating or for sanitary purposes only.

The incorporation of a buffer tank may bring economic benefits, as the storage of heat gives the system more flexibility for meeting local thermal demands. In addition, a tank may improve the operation of the micro-CHP unit in terms of a smoother operation. Decreased deterioration may be an attractive feature to manufacturers wishing to commercialize micro-CHP units.

For the purpose of analyzing the sensitivity of the model to the incorporation of a heat storage tank, we work with two basic intelligent-control cases: *chp_tank* and *chp_notank* cases. The first one represents the case of a heating system with a micro-CHP unit, auxiliary boiler and a buffer tank. The second one characterizes a heating system with a micro-CHP unit, auxiliary warm-air furnace and without a tank. Both cases are also compared with our initial *reference case*, which was defined as such a system where households do not have a micro-CHP unit, but they rely on a conventional heating system and the power grid connection for local energy needs.

The mathematical formulations of both *chp_tank* and *chp_notank* cases are similar to that explained in Chapter 3 for the intelligent-control strategy. However, as the *chp_notank case* has no tank, the dynamic equations are not required and it becomes a simple linear problem, where decision variables from one hour are independent from the next one.

For the *chp_tank case* recall that the incorporation of hot-water storage tank in the model required a dynamic programming formulation. As explained in the previous chapter, the dynamics of the model are given by:

$h_{k+1}^{\tan k} = h_k^{\tan k} + h_k^{in} - h_k^{load}$, with k=1,2,...,N

The stored heat during the next hour depends on the incoming heat from the micro-CHP and boiler units, the stored heat from the previous hour, and the local heat requirements for that hour. Under this formulation, the optimization process needs to be done on an hourly basis for the overall time horizon being modeled (i.e. 365 periods of 24 hours or 1 period of 8760 hours). In addition, for the buffer tank we assumed a heat capacity of 5kWh.

In understating the impact of having a buffer tank, we perform three analyses that take into consideration the technical characteristics of the micro-CHP unit:

- Based on micro-CHP discrete output and medium HPR,
- Based on micro-CHP continuous output and medium HPR, and
- Based on micro-CHP discrete output and low HPR.

The analyses performed in Chapter 3 were based on the current characteristics of an ICE-based micro-CHP being commercialized in the US. However, we recognize that the technology may change to allow a modulating operation[58]. In addition, other technologies may be used instead of an IC engine, like Fuel Cells (FC) with higher electric efficiency and lower heat-to-power ratio values.

[58] Such technology is being developed by some manufacturers already (refer to Chapter 2).

4.1.1. Results for discrete operation and medium HPR

Under this analysis, the micro-CHP has three possible discrete power outputs of 1.37, 2.37 and 4.7 kWe. With a HPR of 2.7, the heat outputs range from 3.7 up to 12.7 kWth (refer to Chapter 3 for details on the technical parameters included in the model).

In Table 4.1-1 we see that a heating system with a buffer tank brings more annual energy cost savings than the warm-air configuration with no tank.

Cases	*Energy cost* [$/yr]	*Savings* [%]
reference	3,181	0%
chp_tank	2,632	17%
chp_notank	2,810	12%

Table 4.1-1: Annual energy costs

In Table 4.1-2 and Table 4.1-3 we also see better annual outcomes in terms of energy efficiency and CO2 emissions for the case with buffer tank.

Cases	*Energy effiency** [%/yr]	*Increment* [%]
reference	57%	0%
chp_tank	69%	21%
chp_notank	65%	14%

Table 4.1-3: Annual energy efficiency

	CO2 emissions					
Cases	*Total* [metric ton/yr]	*Reductions* [%]	*from fuel* [metric ton/yr]	*from import* [metric ton/yr]	*from export* [metric ton/yr]
reference	9.99		4.72	5.28	-
chp_tank	7.82	22%	6.65	2.97	(1.80)
chp_notank	8.52	15%	6.21	3.66	(1.35)

Table 4.1-2: Net CO2 emissions

In Figure 4.1.2 we see that the buffer tank allows a greater use of the micro-CHP unit with less excess heat. The capacity factor of the machine is increased from 15% to 21%[59] when incorporating a buffer tank to the heating system.

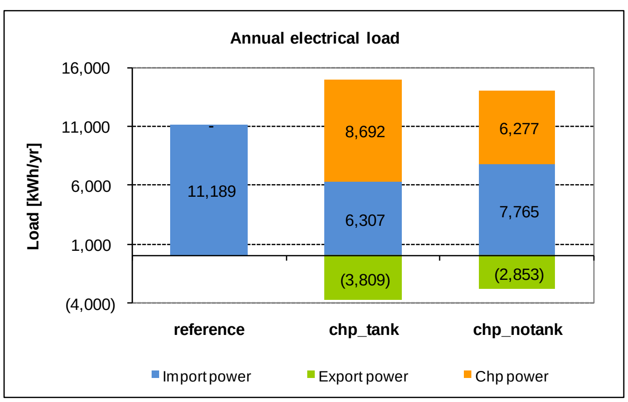

Figure 4.1.2a: Annual power imports, micro-chp electric power and electricity surplus exported back to the grid

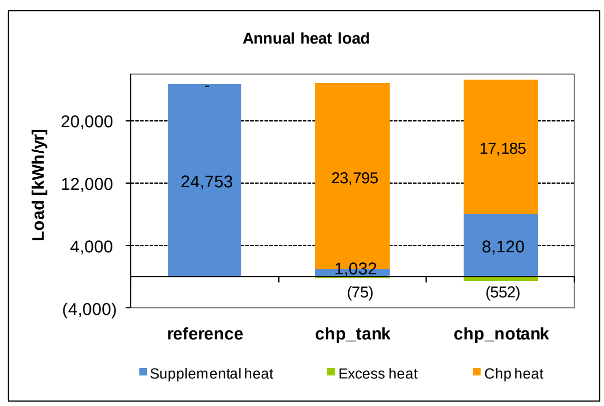

Figure 4.1.2b: Annual supplemental heat, micro-chp heat and excess heat

[59] Value calculated over maximum electrical output of the micro-CHP, i.e. 4.7kWe.

In summary we note that, in terms of annual results, the buffer tank:

- Increases from 12% up to 17% the energy cost savings.
- Improves from 14% up to 21% the energy efficiency.
- Increases from 15% up to 22% the CO_2 emissions reductions.

However, we also need to look at other aspects of the operation of the micro-CHP unit. Thus, we are interested in understanding *whether the micro-CHP operation is smoother with a buffer tank than without the tank under the least-cost optimization criterion*.

For responding this question, we look into changes of the micro-CHP output levels during 1 year of operation. Thus, we define three metrics:

1. *Micro-chp on* measures the hours the micro-CHP is operating during the year.
2. *Output*-level change defines the number of times the micro-CHP changes value in the following hour. Recall that the micro-CHP has four possible discrete values different (0, 1.37, 2.37 and 4.7kWe), so we define three output-levels: 1-level for small changes[60], 2-level for bigger changes[61], and 3-level for big changes[62].
3. *On/off change* defines the number of times the micro-CHP turns on or turns off. For example, if the micro-CHP goes from 0kWe to 1.37kWe, or from 0kWe to 2.37kWe, or from 0kWe to 4.7kWe.

In Table 4.1-4 and Table 4.1-5 we see the results for each the defined metrics. Results with a buffer tank show that the micro-CHP increases its operation from 34% to 48% of the time (see "*chp on*" metric), especially during summer when the micro-CHP operates some hours during the day to fill the tank up. Looking at other changes of the micro-CHP operation, we see that the majority of the output changes occur in the 1-level change, i.e. going from one state of operation to the next one. The case with buffer tank shows a significant number of 1-level change, while it shows a small number of 3-level change.

	chp_notank				
Month	***chp on*** [hr/mo]	***1-level change*** [times/mo]	***2-level change*** [times/mo]	***3-level change*** [times/mo]	***on/off change*** [times/mo]
January	657	163	36	2	36
February	555	165	33	2	38
March	479	165	43	3	50
April	219	123	25	13	48
May	38	24	12	4	14
June	-	-	-	-	-
July	-	-	-	-	-
August	-	-	-	-	-
September	-	-	-	-	-
October	68	51	13	9	25
November	405	137	28	9	50
December	555	165	34	7	47
Total	**2,976**	**993**	**224**	**49**	**308**

Table 4.1-4: Micro-CHP operation for chp_notank case

[60] For example, if the micro-CHP goes from 0kWe to 1.37kWe, or from 1.37kWe to 2.37kWe, or from 2.37kWe to 4.7kWe (or vice versa).
[61] For example, if the micro-CHP goes from 0kWe to 2.37kWe, or from 1.37kWe to 4.7kWe (or vice versa).
[62] For example, if the micro-CHP goes from 0kWe to 4. 7kWe (or vice versa).

Month	chp_tank				
	chp on [hr/mo]	***1-level change*** [times/mo]	***2-level change*** [times/mo]	***3-level change*** [times/mo]	***on/off change*** [times/mo]
January	686	310	39	-	37
February	585	276	39	1	46
March	559	325	29	1	76
April	348	280	34	3	110
May	175	278	7	1	135
June	138	262	-	-	131
July	140	266	-	-	133
August	142	278	-	-	139
September	135	260	-	-	130
October	195	279	14	1	132
November	493	271	25	2	74
December	620	287	40	4	55
Total	**4,216**	**3,372**	**227**	**13**	**1,198**

Table 4.1-5 Micro-CHP operation for chp_tank case

For large 3-level or 2-level changes, the micro-CHP operation can be considered *not smooth* as it needs to rapidly jump from one state to a much higher. However, for small 1-level changes it is hard to say whether the micro-CHP runs smooth or not. This level of change may indicate that the micro-CHP either gradually steps up or down (smooth) or simply oscillates between outputs (not smooth). *Consequently, it is difficult to claim that the operation of the micro-CHP is more regular with a buffer tank.*

In the following figures we illustrate the operation of the micro-CHP for different days of the year we have modeled. We showed two sets of figures: irregular vs. smooth operation (Figure 4.1.5 and Figure 4.1.8 respectively).

Examples of irregular micro-CHP operation with tank

Case without tank (red) vs. Case with tank (blue)

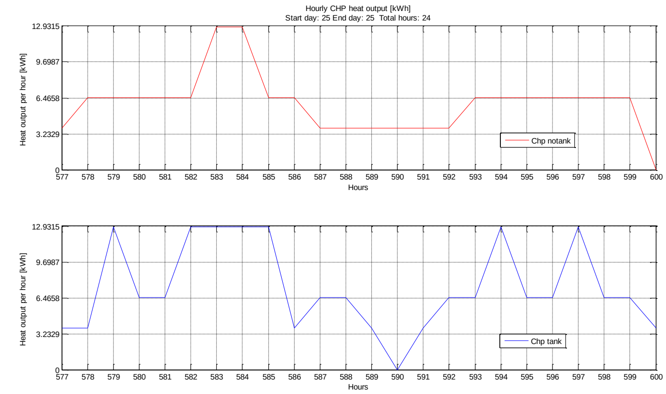

Figure 4.1.5a: One day of operation in January/Winter

See oscillating operation of micro-CHP with buffer tank (blue line)

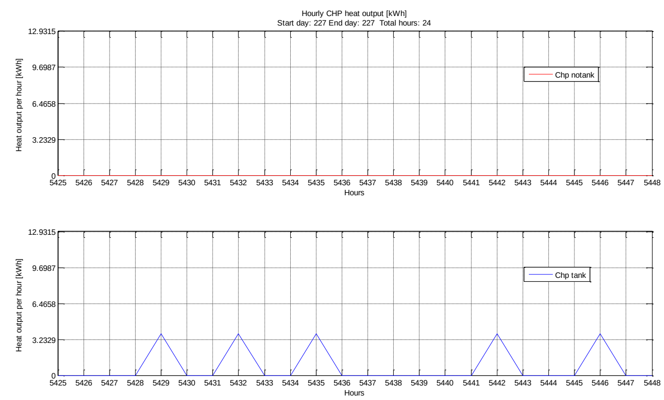

Figure 4.1.5b: One day of operation in August/Summer

See on/off operation of micro-CHP with buffer tank (blue line)

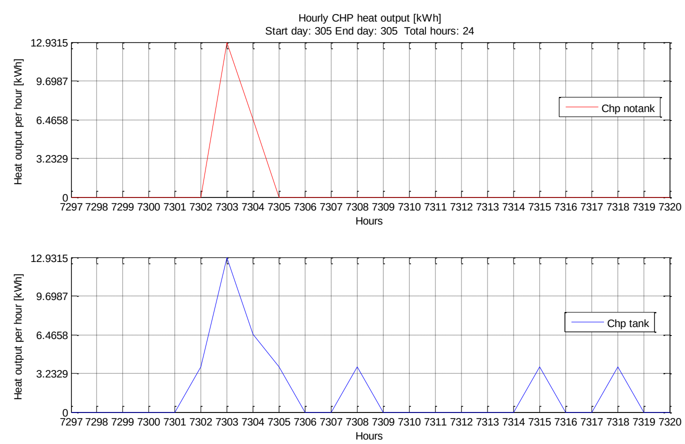

Figure 4.1.5c: One day of operation in November/Fall

See mixed operation: gradual step up/down, and oscillating operation with buffer tank (blue line)

Examples of smooth micro-CHP operation with tank

Case without tank (red) vs. Case with tank (blue)

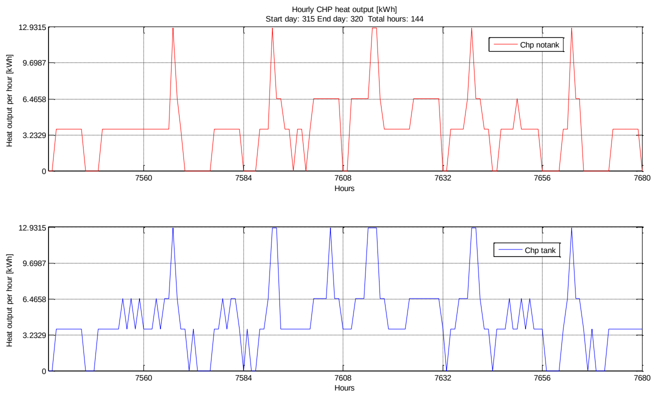

Figure 4.1.8a: Six days of operation in November/Winter

See mixed operation: gradual increase/decrease output, and on/off operation (blue line)

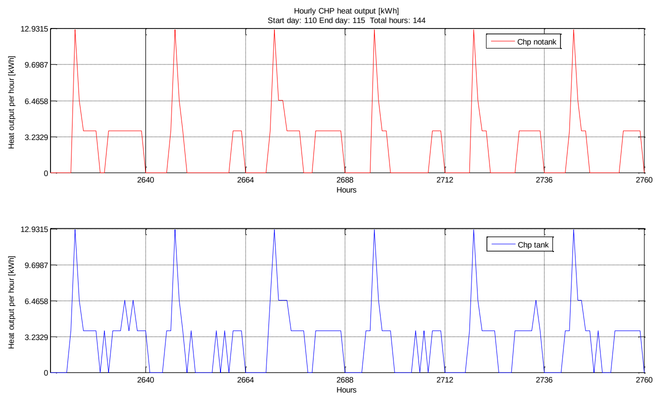

Figure 4.1.8b: Six days of operation in April/Spring

See mixed operation: gradual increase/decrease output, and on/off operation (blue line)

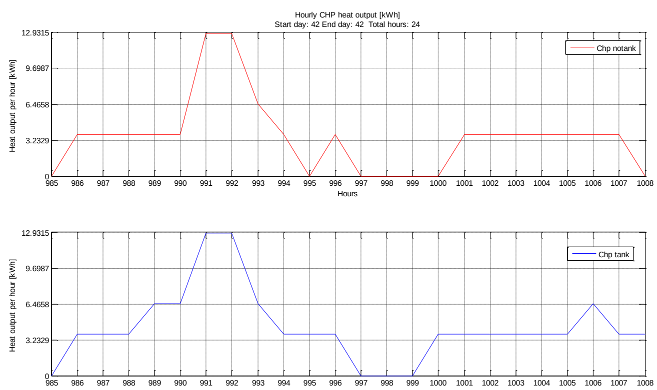

Figure 4.1.8c: One day of operation in February

See gradual output level increase (blue line)

Looking at these figures and the previous metrics, it is not clear whether the operation of the micro-CHP is smooth when incorporating a buffer tank in the heating system configuration. During the year, we find that with the tank the machine oscillates between outputs, and it turns on and off for a few hours especially during summer days. However, we also find that there are times when the machine operates gradually, without some of the sudden output level increases or decreases we have found in the case without buffer tank.

A possible explanation for these results may be that the operation of the micro-CHP can oscillate between three discrete outputs, making it difficult to see the impact of having a hot water tank. Therefore, in the next section we investigate this feature and we will allow the micro-CHP unit to modulate smoothly between specific values.

4.1.2. Results for continuous operation and medium HPR

For this analysis, we modify the discrete characteristics of the micro-CHP unit to a fully modulating machine. We include the operational restriction that the micro-CHP electric output has to be above 10% of its maximum capacity. Below this value, the micro-CHP turns off.

Therefore, under the intelligent-control strategy formulation we modify some of the power-related constraints. In the discrete model we had the following equations:

$$u_k + x_k + y_k + z_k = 1$$
$$e_k^{chp1} = u_k \cdot E^{chp1}$$
$$e_k^{chp2} = x_k \cdot E^{chp2}$$
$$e_k^{chp3} = y_k \cdot E^{chp3}$$
$$e_k^{chp4} = z_k \cdot E^{chp4}$$
$$e_k^{chp} = e_k^{chp1} + e_k^{chp2} + e_k^{chp3} + e_k^{chp4}$$

In the continuous formulation we replace these expressions with:

$$e_k^{chp} = \begin{cases} e_k^{chp} & \text{if } 10\% \cdot E^{chp4} \le e_k^{chp} \le E^{chp4} \\ 0 & \text{if } e_k^{chp} < 10\% \cdot E^{chp4} \end{cases}$$
$$e_k^{chp} >= 0$$

Where,

$$E^{chp4} = 4.70kWe$$
$$H^{chp4} = 12.5kWth$$
$$\eta_e^{chp} = 24.4\%, \eta_{th}^{chp} = 66.8\%$$
$$\eta_{th}^{aux} = 95\%$$
$$\frac{\eta_{th}^{chp}}{\eta_e^{chp}} = 2.7$$

As in the previous section, results are presented for the cases with tank (*chp_tank_cont*) and without tank (*chp_notank_cont*) for continuous operation.

Cases	Energy cost [$/yr]	Savings [%]
reference	3,181	0%
chp_tank_cont	2,608	18%
chp_notank_cont	2,678	16%

Table 4.1-6: Annual energy costs for continuous case

In Table 4.1-6 we see that under continuous operation of the micro-CHP unit, a system with buffer tank does not bring much more energy cost savings than the system without tank. In both case the micro-CHP heat production is closer to the local heat need, especially in the case without tank where the micro-CHP has the flexibility to produce more heat without having to discarding the excess.

In Table 4.1-7 and Table 4.1-8 we also see little difference between both cases in terms of energy efficiency improvement and CO_2 emissions reductions.

Cases	Energy effiency* [%/yr]	Increment [%]
reference	57%	0%
chp_tank_cont	71%	24%
chp_notank_cont	68%	20%

Table 4.1-7: Annual efficiency for continuous case

	CO2 emissions				
Cases	***Total*** [metric ton/yr]	***Reductions*** [%]	***from fuel*** [metric ton/yr]	***from import*** [metric ton/yr]	***from export*** [metric ton/yr]
reference	9.99		4.72	5.28	-
chp_tank_cont	7.76	22%	6.68	2.65	(1.57)
chp_notank_cont	8.00	20%	6.71	2.91	(1.62)

Table 4.1-8: Net CO2 emissions for continuous case

In Figure 4.1.10 we see that a continouos operation allows the micro-CHP to generate more heat close to the load. Both cases, i.e. with and without tank, have a similar capacity factor[63] of 22% and 21% respectively.

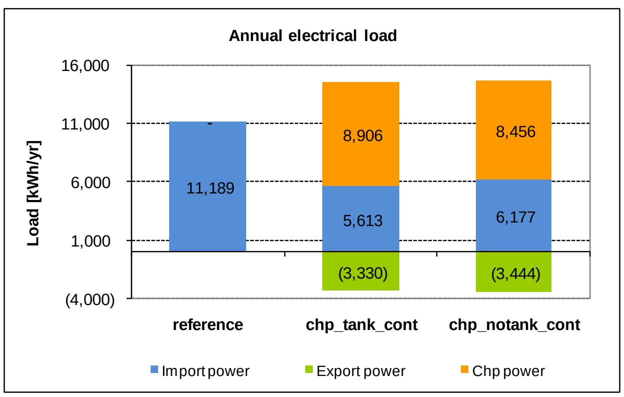

Figure 4.1.10a: Annual power imports, micro-chp electric power and electricity surplus exported back the grid for continuous case

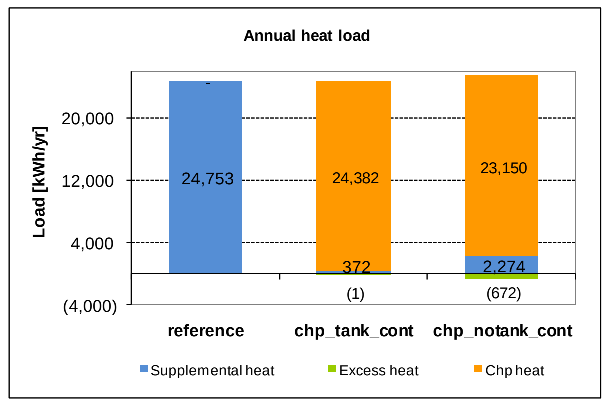

Figure 4.1.10b: Annual supplemental heat, micro-chp heat and excess heat for continuous case

In summary we note that, in terms of annual results, the buffer tank under a continuous micro-CHP operation brings better results:

- Increases from 16% up to 18% the energy cost savings.
- Improves from 20% up to 24% the energy efficiency.
- Increases from 20% up to 22% the CO2 emissions reductions.

As with the previous section, we also need to understand whether the micro-CHP operation is smoother with a buffer tank than without it under continuous operation. For this purpose we define three metrics:

1. *Micro-chp on* measures the hours the micro-CHP is operating during the year.
2. *Output-level change* defines the number of times the micro-CHP changes its output level in the following hour. As the operation of the micro-CHP is continuous, we define the changes based on the amount of kWe. Therefore, we

[63] Value calculated over maximum electrical output of the micro-CHP, i.e. 4.7kWe

defined five output-levels: 0-1kW change[64], 1-2kW change[65], 2-3kW change[66], 3-4kW change[67], 4-4.7kW change[68].

3. *On/off change* defines the number of times the micro-CHP turns on or turns off. For example, when the micro-CHP goes from 0kWe to any positive value.

Looking at Table 4.1-9 and Table 4.1-10, we see that the buffer tank increases the operation of the micro-CHP from 69% to 76% of the time (see "*chp on*" metric), and the machine turns on/off more times during summer. However, we note that high-level output changes occur more frequently for the case with no tank, i.e. between 2kWe and 4.7kWe changes.

Month	chp on [hr/mo]	0-1kW change [times/mo]	1-2kW change [times/mo]	*chp_notank* 2-3kW change [times/mo]	3-4kW change [times/mo]	4-4.7kW change [times/mo]	on/off change [times/mo]
January	683	583	65	35	11	2	32
February	601	506	67	26	15	-	33
March	596	490	67	40	13	2	46
April	453	348	45	26	20	7	59
May	429	236	11	9	6	2	59
June	420	240	-	-	-	-	60
July	420	240	-	-	-	-	60
August	434	248	-	-	-	-	62
September	406	232	-	-	-	-	58
October	432	236	18	14	5	8	61
November	539	454	56	22	14	7	44
December	631	532	60	34	12	7	36
Total	**6,044**	**4,345**	**389**	**206**	**96**	**35**	**610**

Table 4.1-9: Micro-CHP operation for chp_notank case

Month	chp on [hr/mo]	0-1kW change [times/mo]	1-2kW change [times/mo]	*chp_tank* 2-3kW change [times/mo]	3-4kW change [times/mo]	4-4.7kW change [times/mo]	on/off change [times/mo]
January	740	522	180	25	2	-	2
February	672	502	135	18	4	-	-
March	728	568	101	26	5	-	10
April	635	476	48	16	17	-	52
May	458	421	5	5	2	-	150
June	387	389	-	-	-	-	180
July	395	397	-	-	-	-	180
August	406	405	-	-	-	-	185
September	379	382	-	-	-	-	175
October	504	435	18	6	7	-	133
November	687	531	78	32	8	-	18
December	729	558	126	22	8	-	8
Total	**6,720**	**5,586**	**691**	**150**	**53**	**-**	**1,093**

Table 4.1-10: Micro-CHP operation for chp_tank case

As we can see from the analysis for continuous operation, less high-level changes occur in the application with buffer tank, and no sudden increases/decreases are in the range on 4 to 4.7kWe. We still see that during summer the micro-CHP operates for some hours during the day, and we also see more small-changes throughout the year. Now, *when compared to the discrete operation described in the previous section, we see more clearly the effect of incorporating a buffer tank, as the micro-CHP operation has less drastic changes.*

[64] If the micro-CHP changes less than 1kWe from one hour to the next.
[65] If the micro-CHP changes between 1kWe and 2kWe from one hour to the next.
[66] If the micro-CHP changes between 2kWe and 3kWe from one hour to the next.
[67] If the micro-CHP changes between 3kWe and 4kWe from one hour to the next.
[68] If the micro-CHP changes between 4kWe and 4.7kWe from one hour to the next.

In the following figures we illustrate the operation of the micro-CHP for the continuous cases. We showed two sets of figures: irregular vs. smooth operation (Figure 4.1.12, and Figure 4.1.15 respectively).

Examples of irregular micro-CHP operation with tank – Continuous case

Case without tank (red) vs. Case with tank (blue)

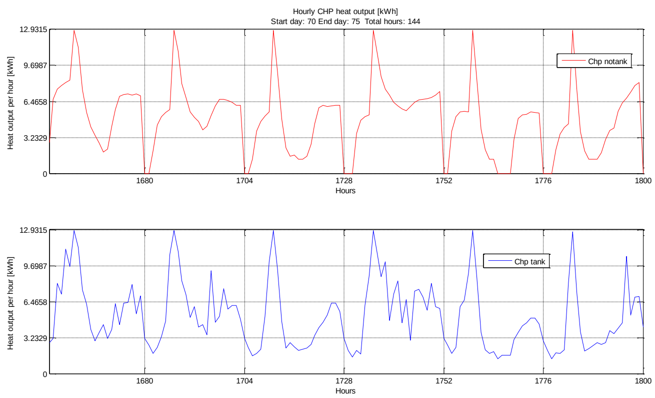

Figure 4.1.12a: Six days of operation in March/Spring

See oscillating operation of micro-CHP with buffer tank (blue line)

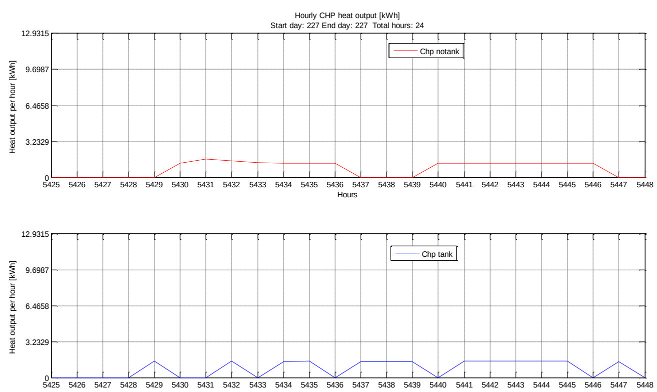

Figure 4.1.12b: One day of operation in July/Summer

See on/off operation of micro-CHP with buffer tank (blue line)

Examples of smooth micro-CHP operation with tank – Continuous case

Case without tank (red) vs. Case with tank (blue)

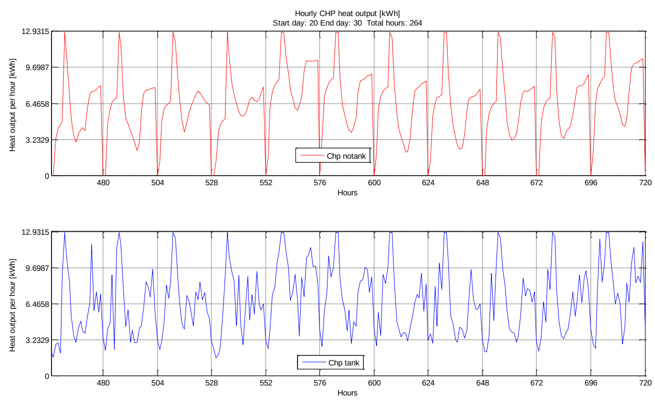

Figure 4.1.15a: Eleven days of operation in January/Winter

See less number of on/off change of micro-CHP with buffer tank (blue line)

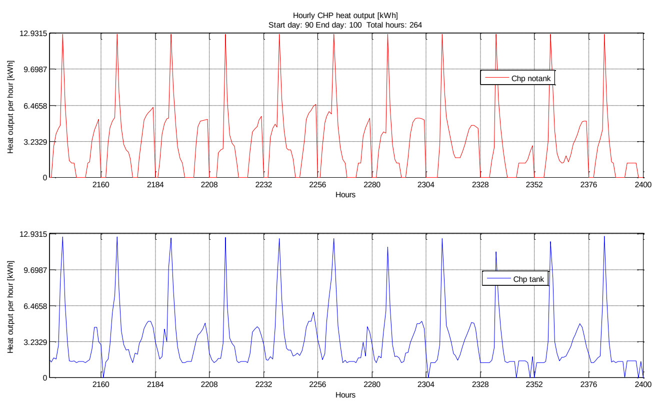

Figure 4.1.15b: Eleven days of operation in April/Spring

See less number of sudden increase/decrease of micro-CHP with buffer tank (blue line)

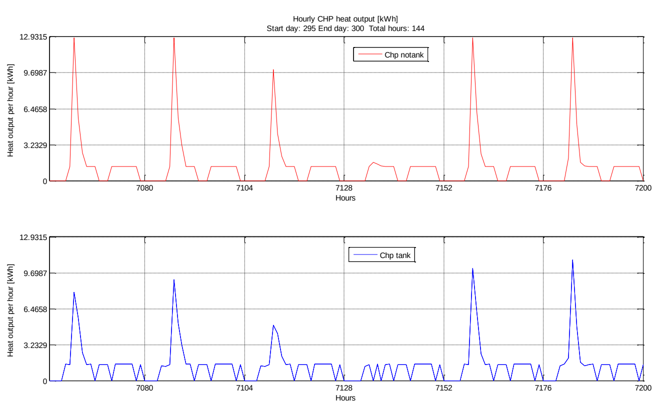

Figure 4.1.15c: Six days of operation by end of September

See peak output reduction of micro-CHP with buffer tank (blue line)

A continuous operation of the micro-CHP brings much more hours of operation of the machine. In terms of annual results, the incorporation of a buffer tank brings better economic, environmental and efficiency results when compared to the case with no tank. However, the level of improvements is not as drastic to those measured for the discrete case.

In terms of operational output, we see that under a continuous operation the micro-CHP has a more regular operation, with fewer 2kWe to 4.7kWe changes. Still, with the buffer tank, we have several small operational changes and an on/off operation during the summer.

4.1.3. Results for discrete operation and low HPR

For this analysis, we modify the technology used in the simulations. We change the electricity and thermal efficiency values that lead to a different heat-to-power ratio of micro-CHP unit. We maintain the discrete electrical outputs. However, because of the new HPR, new discrete heat outputs are adopted.

Recall that under the original intelligent-control strategy formulation, we had micro-CHP electric and heat efficiencies of $\eta_e^{chp} = 24.4\%$ and $\eta_{th}^{chp} = 66.8\%$ respectively. The HPR using these values was $\frac{\eta_{th}^{chp}}{\eta_e^{chp}} = 2.7$. In addition, the three possible discrete electrical outputs of the micro-CHP were:

$$E^{chp1} = 0.00kWe$$
$$E^{chp2} = 1.37kWe$$
$$E^{chp3} = 2.37kWe$$
$$E^{chp4} = 4.70kWe$$

As the micro-CHP HPR was 2.7, the possible discrete heat outputs were:

$$H^{chp1} = 0.00kWth$$
$$H^{chp2} = 3.7kWth$$
$$H^{chp3} = 6.4kWth$$
$$H^{chp4} = 12.5kWth$$

For the *new case with different technology*, we adopt efficiency values based on fuel cell-based micro-CHP[69]. Now we use $\eta_e^{chp} = 50\%$ and $\eta_{th}^{chp} = 30\%$, and the new heat-to-power ratio is $HPR = 0.6$. Using the same electrical outputs, we calculate the three new discrete thermal outputs of the machine:

$$H^{chp1\_hpr06} = 0.00kWth$$
$$H^{chp2\_hpr06} = 0.82kWth$$
$$H^{chp3\_hpr06} = 1.42kWth$$
$$H^{chp4\_hpr06} = 2.82kWth$$

Using these new values and based on the least-cost model, new simulations are performed to analyze the impact of a heat storage tank. As before, results are showed for *reference, chp_tank* and *chp_notank cases*, i.e. households without micro-CHPs, residential dwellings with a micro-CHP unit and a buffer tank, and households with an micro-CHP unit and no tank, respectively.

[69] Loosely based on BlueGen(49).

Results in Table 4.1-11 show, as in previous results, that a heating system with a buffer tank brings more cost savings than the configuration with no tank, although both results are similar.

Cases	Energy cost [$/yr]	Savings [%]
reference	3,181	0%
chp_tank_hpr06	1,791	44%
chp_notank_hpr06	1,872	41%

Table 4.1-11: Annual energy costs for low HPR case

In Table 4.1-12 and Table 4.1-13 we also see better results, in terms on annual energy efficiency and CO_2 emissions, for the configuration with buffer tank. Again, in both cases results are very close.

Cases	Energy effiency* [%/yr]	Increment [%]
reference	57%	0%
chp_tank_hpr06	72%	26%
chp_notank_hpr06	71%	24%

Table 4.1-12: Annual efficiency for low HPR case

	CO2 emissions				
Cases	Total [metric ton/yr]	Reductions [%]	from fuel [metric ton/yr]	from import [metric ton/yr]	from export [metric ton/yr]
reference	9.99		4.72	5.28	-
chp_tank_hpr06	2.91	71%	16.23	0.00	(13.33)
chp_notank_hpr06	3.18	68%	16.35	0.00	(13.17)

Table 4.1-13: Net CO2 emissions for low HPR case

In Figure 4.1.17 we clearly see that under both configurations, the micro-CHP operation is pretty similar. Indeed, the capacity factor[70] of the machine is 96% and 95% for the cases with buffer tank, and no tank respectively.

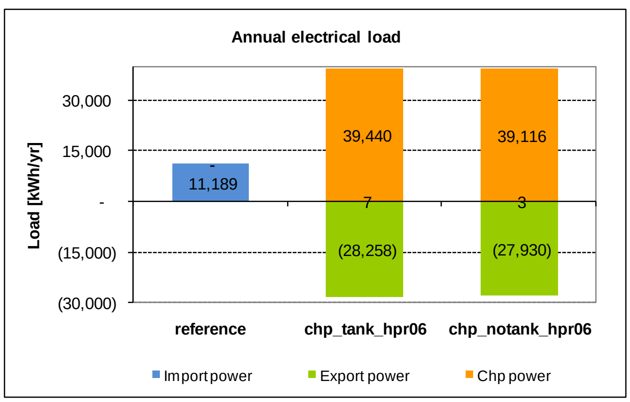

Figure 4.1.17a: Annual power imports, micro-chp electric power and electricity surplus exported back the grid for low HPR case

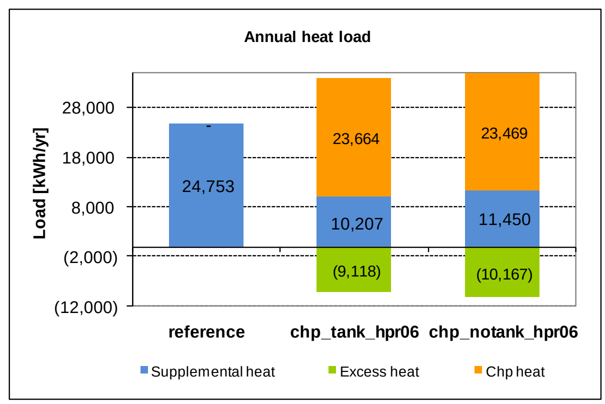

Figure 4.1.17b: Annual supplemental heat, micro-chp heat and excess heat for low HPR case

In summary we note that, even when the economic, efficiency and CO_2 outcomes are better with a buffer tank, the results of both configurations are similar. *Under an intelligent least-cost control, the machine with a lower HPR tries to operate most of the time at maximum capacity. The micro-CHP sees the economic incentive of getting revenues from the electricity being exported back to the grid. Therefore, under both configurations, the micro-CHP is continuously operating and the buffer tank does not play a critical role*.

We will also look at the operation of the machine with the purpose of understanding whether it is more regular or not with a buffer tank. Therefore, for the news cases we measure the three metrics defined already for the discrete case[71].

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[70] Value calculated over maximum electrical output of the micro-CHP, i.e. 4.7kWe.

Table 4.1-14 and Table 4.1-15 show the year-round flat operation of the micro-CHP under both configurations. With a low HPR, the micro-CHP operates continuously 100% of the time in both cases (see "*chp on*" metric). We also see some small and large-change outputs, the latter being fewer for the case with a buffer tank (although it is a marginal improvement).

Month	chp_notank_hpr06				
	chp on [hr/mo]	***1-level change*** [times/mo]	***2-level change*** [times/mo]	***3-level change*** [times/mo]	***on/off change*** [times/mo]
January	744	-	-	-	-
February	672	-	-	-	-
March	744	-	1	-	-
April	720	146	41	-	-
May	744	-	-	-	-
June	720	-	-	-	-
July	744	-	-	-	-
August	744	-	-	-	-
September	720	-	-	-	-
October	744	-	1	-	-
November	720	78	51	-	-
December	744	-	-	1	-
Total	**8,760**	**224**	**94**	**1**	**-**

Table 4.1-14: Micro-CHP operation for chp_notank case

Month	chp_tank_hpr06				
	chp on [hr/mo]	***1-level change*** [times/mo]	***2-level change*** [times/mo]	***3-level change*** [times/mo]	***on/off change*** [times/mo]
January	744	-	-	-	-
February	672	-	-	-	-
March	744	-	-	-	-
April	720	192	40	-	-
May	744	-	-	-	-
June	720	-	-	-	-
July	744	-	-	-	-
August	744	-	-	-	-
September	720	-	-	-	-
October	744	-	1	-	-
November	720	110	31	-	-
December	744	-	-	1	-
Total	**8,760**	**302**	**72**	**1**	**-**

Table 4.1-15: Micro-CHP operation for chp_tank case

In the following figures, we illustrate the operation of the micro-CHP for the case with low HPR. We will see how flat the operation is throughout the year. In addition we show the behavior of the tank and boiler, and the power-related outputs of the local electrical system for some days in summer and winter (Figure 4.1.19, Figure 4.1.21, and Figure 4.1.23).

[71] Refer to Section 4.1.1.

Examples of micro-CHP operation – Low HPR case

Case without tank (red) vs. Case with tank (blue)

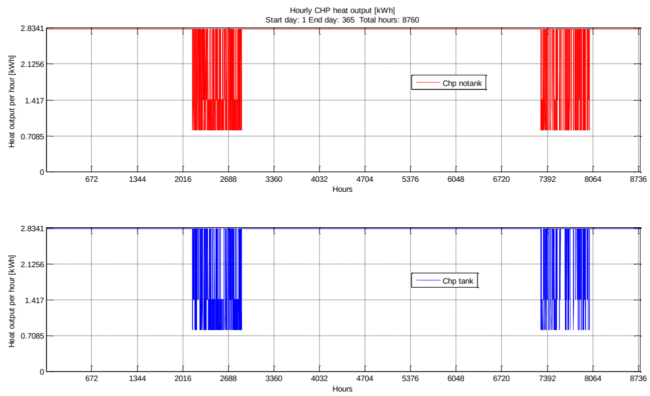

Figure 4.1.19a: Operation during 365 days of the year

See varying operation during April and November, and flat operation during rest of year. The operation is similar for both cases

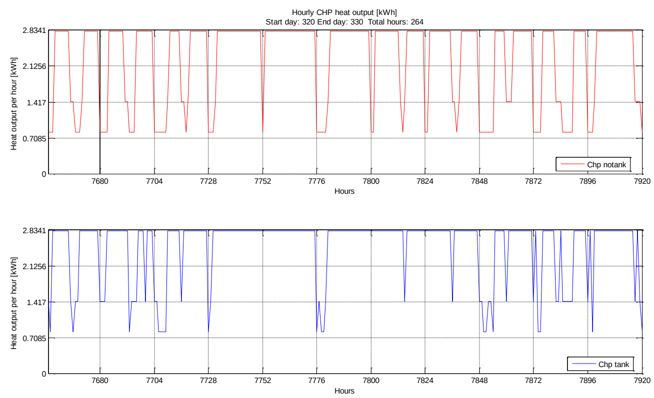

Figure 4.1.19b: Eleven days of operation in November/Fall

See similar operation of micro-CHP in both cases

Examples of micro-CHP operation in summer – Low HPR case

Case with buffer tank

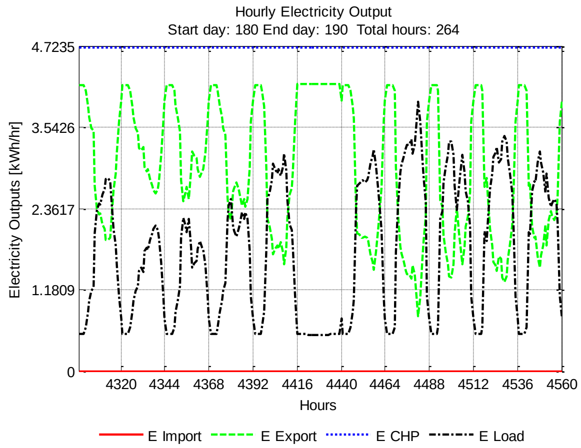

Figure 4.1.21a: Power output for eleven days of operation in July/Summer

See flat operation of micro-CHP with electricity exports:

- Blue line for micro-CHP power output
- Red line for electric power imports
- Green line for electric power exports
- Black line for local electric load

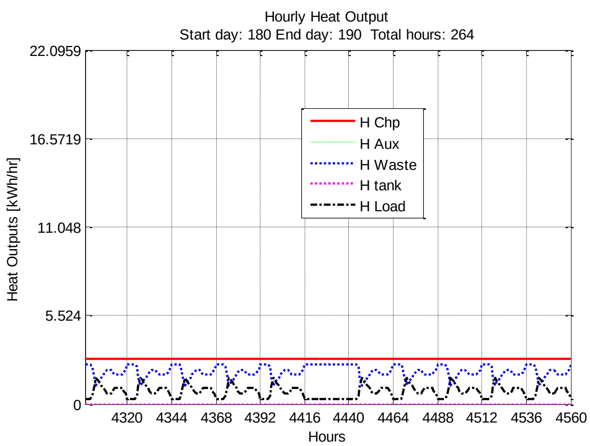

Figure 4.1.21b: Heat output for eleven days of operation in July/Summer

See flat operation of micro-CHP with excess heat and no stored heat:

- Red line for micro-CHP heat output
- Green line for boiler heat output
- Blue line for excess heat
- Purple line for stored heat
- Black line for local heat load

Examples of micro-CHP operation in winter – Low HPR case

Case with buffer tank

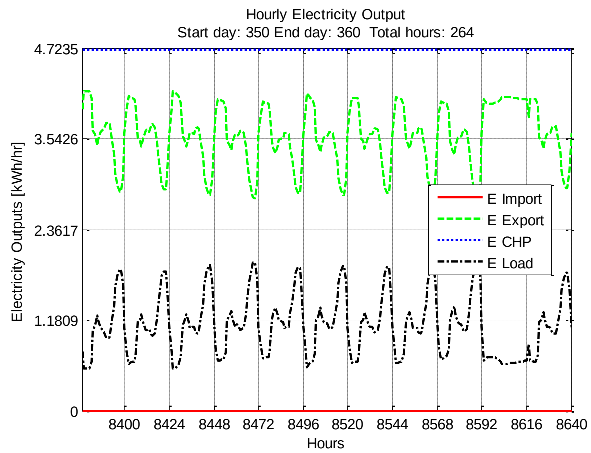

Figure 4.1.23a: Power output for eleven days of operation in December/Winter

See flat operation of micro-CHP with electricity exports:

- Blue line for micro-CHP power output
- Red line for electric power imports
- Green line for electric power exports
- Black line for local electric load

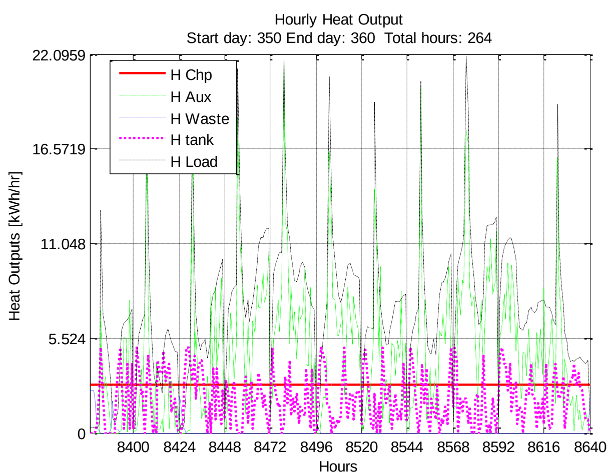

Figure 4.1.23b: Heat output for eleven days of operation in December/Winter

See flat operation of micro-CHP with supplemental heat and stored heat:

- Red line for micro-CHP heat output
- Green line for boiler heat output
- Blue line for excess heat
- Purple line for stored heat
- Black line for local heat load

As we have seen, a micro-CHP unit with low HPR operates year round at constant output most of the time. The incorporation of a buffer tank does not make much difference in terms of either annual results operational behavior. Under the new assumption, the micro-CHP tries to take advantage of the gas price and the attractive buy-back rate for electricity exports.

4.2. Sensitivity to tank end-state

In the previous chapter we saw that the model formulation to represent the micro-CHP operation with a hot water tank is more complex than that a system without it. Dynamic equations are needed to describe the relationship between the stored heat in an hour and the stored heat in the following hour in the buffer tank.

Under this dynamic programming formulation, we are required to define a state variable, and the initial and final conditions of it. Therefore, we set the amount of heat stored in the tank (h_k^{tank}) to be the state, with the following dynamic:

$$h_{k+1}^{tank} = h_k^{tank} + h_k^{in} - h_k^{load}\text{, with k=1,2,...,N}$$

Here, the initial and last state conditions are labeled as $h_{k=N+1}^{tank}$ and $h_{k=1}^{tank}$, where k=1 and k=N+1 are the first and the last stages (in hours) of the simulation period respectively. The state condition can be interpreted as the heat level content the householder wants to keep in the tank at the end of the period. Thus, he may desire to keep the tank full during winter or peak time, or he may desire to have the tank empty during summer or off-peak time.

As we explain later, the time horizon used in the model may go from one year (LT) to one day (ST) solution. In both cases, we explore the sensitivity of the model to the final state condition, going from empty to full stored heat in the tank.

4.2.1. Results for annual solution

Under the annual solution, we adopted an 8760-hour time horizon where the model is run once over the entire period. Here, we set the end-state condition to be at the last hour of the simulation period, i.e. at 12am December 31 (see Figure 4.2.1).

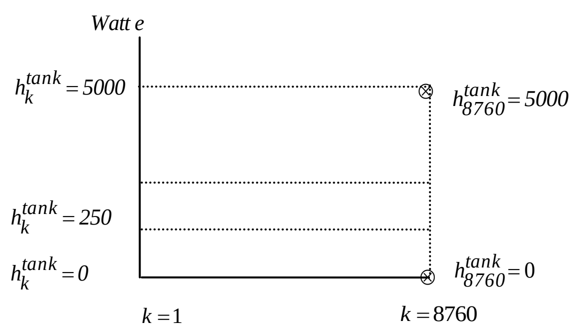

Figure 4.2.1: Annual solution based on one period of 8760 hours
End-state defined at end of year

For analyzing the sensitivity to the tank end condition, we worked on two cases: *full tank* vs. *empty tank*. In the first one we initialize the problem assuming the stored heat in the tank is 5kWh in the last stage. In the second case, we assume the stored heat is 0kWh in the last stage.

Results in Table 4.2-1 through Table 4.2-3 show general monthly outputs for variable energy costs, energy efficiency and CO_2 emissions.

We see that results in both cases have little difference. In fact, only during the first and last month of the simulation period is when these variations occur (see shadowed rows in tables).

Month	Energy costs chp_full_tank_LT [$/yr]	Energy costs chp_emp_tank_LT [$/yr]
January	356.6	356.9
February	276.7	276.7
March	274.5	274.5
April	193.6	193.6
May	139.7	139.7
June	168.5	168.5
July	206.8	206.8
August	198.5	198.5
September	144.0	144.0
October	136.6	136.6
November	229.4	229.4
December	306.4	306.2
Total	**2,632**	**2,632**

Table 4.2-1: Annual energy costs for LT solution

Month	Energy efficiency* chp_full_tank_LT [%/mo]	chp_emp_tank_LT [%/mo]
January	89.67%	89.70%
February	88.31%	88.31%
March	84.39%	84.39%
April	71.64%	71.64%
May	50.82%	50.82%
June	43.42%	43.42%
July	41.28%	41.28%
August	42.19%	42.19%
September	44.92%	44.92%
October	55.69%	55.69%
November	81.68%	81.68%
December	87.50%	87.46%
Total	**69.00%**	**69.00%**

Table 4.2-3: Annual efficiency for LT solution

Month	Net CO2 emissions chp_full_tank_LT [Metric ton/mo]	chp_emp_tank_LT [Metric ton/mo]
January	0.880	0.881
February	0.747	0.747
March	0.728	0.728
April	0.554	0.554
May	0.502	0.502
June	0.592	0.592
July	0.714	0.714
August	0.671	0.671
September	0.522	0.522
October	0.472	0.472
November	0.631	0.631
December	0.810	0.810
Total	**7.824**	**7.824**

Table 4.2-2: Net CO2 emissions for LT solution

These results indicate that, for a small tank the final condition of the stored heat in the buffer tank has little impact on the micro-CHP operation. Therefore, householders could broadly estimate the potential benefits of micro-CHPs regardless of the stored heat condition in the tank. Recall that for the simulations we use a size tank of 40 gallons with a heat capacity of 5kWh, i.e. about 0.2% the residential annual heat load. *We did not investigate how results change if a bigger tank were incorporated in the heating system*.

4.2.2. Results for daily solution

For operational purposes, a shorter time horizon may be more appropriate. Deciding the daily operation of the micro-CHP unit may require having information of the energy system closer in time to when the decision has to be taken. Short-term estimations will have less uncertain information, such as the weather conditions and energy prices for the following day. If the householder is able to have access to this information, he could control in an intelligent manner the micro-CHP operation for the next day.

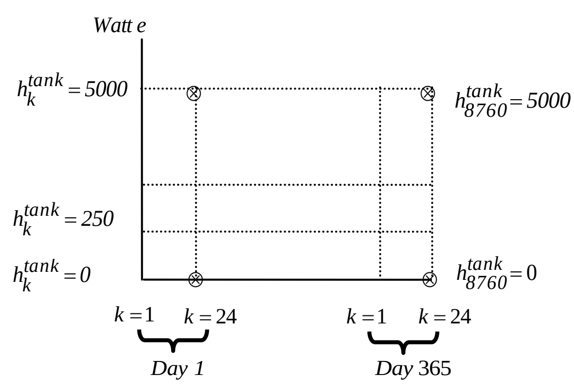

Figure 4.2.2: Daily solution based on 365 periods of 24 hours each.
End-state defined at end of each day

Under the daily solution of the least-cost optimization formulation, we adopted a 24-hour time horizon where the model is run 365 times over the entire year. The end-state condition is set for the last hour of the simulation period, i.e. at 12am of each day (see Figure 4.2.2).

For the purpose of analyzing the sensitivity of the outputs to the tank end condition, we create three cases: full tank, empty tank and optimum tank. For the first two cases, i.e. *full_tank_ST* and *emp_tank_ST*, we initialize the problem assuming the stored heat to be 5kWh and 0kWh at the end of day. For the last case, i.e. *opt_tank_ST*, we set the end state to be that tank value from the annual solution. Therefore, for this we need to run the LT case first and stored the tank state at the end of each of the 365 days. Then, having these values, we run the ST model assuming the daily last-state conditions to be the ones got from the LT solution[72].

We need to note here that the energy load and price conditions assumed for the daily solution were the same we used for the annual cases. However, it is clear that this will not be the case in the real world, as the annual forecasts will differ from market conditions closer in time to the day when the micro-CHP unit needs to operate.

Results in Table 4.2-4 show monthly outputs for variable energy costs compared to the *full_tank_LT* case. We see that going from a daily optimal state condition to a full (or empty) tank condition increases the energy cost by less than 0.5%. Therefore, if we require the stored heat in the tank to be 5kWh (or 0kWh) at the end of the day, the cost will increase marginally with respect to a daily optimal value (we only show energy costs as difference are minor for energy efficiency and CO_2 emissions outputs).

	Energy costs			
Month	***chp_full_tank_LT*** [$/yr]	***chp_opt_tank_ST*** [$/yr]	***chp_full_tank_ST*** [$/yr]	***chp_emp_tank_ST*** [$/yr]
January	356.6	356.6	357.3	357.4
February	276.7	276.7	277.4	277.3
March	274.5	274.5	275.0	275.0
April	193.6	193.6	194.2	194.3
May	139.7	139.7	140.6	140.7
June	168.5	168.5	169.5	169.7
July	206.8	206.8	207.9	208.0
August	198.5	198.5	199.6	199.7
September	144.0	144.0	145.1	145.2
October	136.6	136.6	137.3	137.3
November	229.4	229.4	229.9	230.2
December	306.4	306.4	306.7	306.9
Total	**2,631.5**	**2,631.5**	**2,640.5**	**2,641.6**

Table 4.2-4: Annual energy costs for LT solution

These results may indicate that, for a small tank and regardless of the state of the tank chosen by the householder at the end of the day, the micro-CHP operational outputs will not change substantially and potential cost increases will be small.

As with the annual analysis, *we did not investigate how results change if a bigger tank were incorporated in the heating system*.

4.3. Sensitivity to energy prices

We have seen in this and the previous chapter that variations in the micro-CHP technology have great impact on the model outputs. Recall that technologies with low heat-to-power ratios (HPR) like fuel cells tend to operate most of the time and at its maximum capacity. However, we saw that technologies with higher HPR had a wide operational output range, with high capacity factor (CF) in winter and low CF in

[72] The reason for doing this case was for assessing the impact of the end-state conditions, if the householder were able to set the heating conditions in the tank close enough to the optimal conditions found in the LT solution.

summer. We noted that these results depend not only on the micro-CHP HPR, but also on the particular conditions being adopted in the simulation, especially energy load and prices.

For further understanding of these results, first we analytically analyze the sensitivity of micro-CHPs to energy prices and load conditions. Then, we illustrate the micro-CHP operation for different cases.

4.3.1. Conceptual analysis

For this analytical analysis we use a much simpler model than that described in Chapter 3. The intelligent-control formulation is based on mixed integer variables, and dynamic equations that describe the discrete outputs of the micro-CHP unit and the stored heat in the buffer tank.

For the analysis we assume the following simplifications: continuous variables without minimum restriction (i.e. micro-CHP is continuously modulating), and no dynamic equations (i.e. warm-air heat configuration without buffer tank). Therefore, the problem becomes a much simpler linear optimization problem (LOP), where the operational strategy in one hour is independent from the operation in the next one.

Under the new formulation, instead of optimizing the energy costs over the entire year of operation, we can optimize on an hourly basis. For each hour of the year, the end-user maximizes his energy profits according to the system's conditions:

$$\pi = \sum_{k=1}^{8760} Max\pi_k = \sum_{k=1}^{8760} Max\left(-P_k^{\$e\_imp} \cdot e_k^{imp} + P_k^{\$e\_\exp} \cdot e_k^{\exp} - P_k^{\$f} \cdot \frac{h_k^{chp}}{\eta_{th}^{chp}} - P_k^{\$f} \cdot \frac{h_k^{aux}}{\eta_{th}^{aux}} \right)$$

Where,

$$e_k^{imp} - e_k^{exp} + e_k^{chp} = e_k^{load}$$
$$e_k^{exp} = Max\left(e_k^{chp} - e_k^{load}, 0\right)$$
$$e_k^{imp} = Max\left(e_k^{load} - e_k^{chp}, 0\right)$$
$$h_k^{chp} + h_k^{aux} - h_k^{waste} = h_k^{load}$$
$$h_k^{waste} = Max\left(h_k^{chp} - h_k^{load}, 0\right)$$
$$h_k^{aux} = Max\left(h_k^{load} - h_k^{chp}, 0\right)$$
$$h_k^{chp} = HPR \cdot e_k^{chp}$$
$$0 \le e_k^{chp} \le E_{max}^{chp}$$
$$0 \le h_k^{aux} \le H_{max}^{aux}$$
$$e_k^{imp}, e_k^{exp}, e_k^{chp}, h_k^{aux}, h_k^{waste} >= 0$$

The solutions to this formulation can be found by inspection and looking at the corners of this linear problem. As a result, we find *four possible operational outputs* for the micro-CHP:

1. *No-operation*, where the machine does not run. Electricity is imported from the grid and heat is generated locally using only auxiliary heating equipments.
2. *Electricity-led operation*, where the micro-CHP follows the residential electric power load. If electric capacity is not enough, then supplemental power may be imported from the grid. As the heat output is a by-product, additional heat may be generated using the furnace, or excess heat may be discarded depending on the local load conditions.
3. *Heat-led operation*, where the micro-CHP follows the residential heat load. If heat capacity is not enough, then auxiliary heat may be produced using the furnace. The power output is a by-product and supplemental power may be imported from the grid, or excess power may be exported back to the grid depending on the residential electricity load.
4. *Base-load operation*, where the micro-CHP operates at its maximum capacity. Depending on the load, it may also be possible to require supplemental energy or remove any energy excess.

In general, we find two sets of conditions that determine the above solutions: i) the relationship between energy prices, i.e. natural gas, retail electricity rate and buy-back rate ($P^{\$f}$, $P^{\$e\_imp}$ and $P^{\$e\_exp}$ respectively), and ii) the relationship between the load's heat-to-power ratio ($\frac{h^{load}}{e^{load}}$) and the micro-CHP's HPR ratio (HPR).

Below we explain the required conditions to obtain each of the solutions in the simplified least-cost optimization formulation.

4.3.1.1. No operation

The required conditions for the micro-CHP's no operation are shown in Table 4.3-1.

	Condition
Electricity prices	$P^{\$e\_exp} < P^{\$e\_imp} < \frac{P^{\$f}}{\eta_e^{chp}} - HPR \cdot \frac{P^{\$f}}{\eta_{th}^{aux}}$
Micro-CHP HPR	$HPR > or < \frac{h^{load}}{e^{load}}$

Table 4.3-1: Conditions for optimum no operation solution

Table 4.3-2 shows the solution under these conditions, on an hourly basis. As the micro-CHP does not operate, the householder needs to purchase electricity from the grid, and produce heat using the conventional heating unit, i.e. the warm-air furnace.

	Energy outputs	
Micro-CHP power/heat	$e^{chp} = 0$	$h^{chp} = 0$
Supplemental/Excess power	$e^{imp} = e^{load}$	$e^{exp} = 0$
Supplemental/Excess heat	$h^{aux} = h^{load}$	$h^{waste} = 0$

Table 4.3-2: No-operation solution

Since the electric marginal cost of the micro-CHP unit (after considering savings from producing heat) is higher than the retail electricity price, there are no incentives for the micro-CHP to operate.

4.3.1.2. Electricity-led operation

The conditions found for an electricity-led operation under an intelligent control strategy are shown in Table 4.3-3. We note that there are two conditions: if the micro-CHP's HPR is larger than the load's HPR, or if it is lower. Under either condition, we get the same solution.

	Condition 1	***Condition 2***
Electricity prices	$P^{\$e\_imp} > \frac{P^{\$f}}{\eta_e^{chp}} > P^{\$e\_\exp}$	$P^{\$e\_imp} > \left(\frac{P^{\$f}}{\eta_{te}^{chp}} - HPR \cdot \frac{P^{\$f}}{\eta_{th}^{aux}} \right) > P^{\$e\_\exp}$
Micro-CHP HPR	$HPR > \frac{h^{load}}{e^{load}}$	$HPR < \frac{h^{load}}{e^{load}}$

Table 4.3-3: Conditions for optimum electricity-led operation

In Table 4.3-4 we see how the solution looks like for a particular hour of operation. The micro-CHP tries to match the electrical load if the machine has enough capacity, otherwise it runs at maximum capacity, and the customer needs to import power for supplemental purposes. In addition, it is impossible to have any excess of electrical power under this solution. Finally, the heat output of the micro-CHP is a by-product, and depending on the size of the heat load it may be possible to generate supplemental heat or discard any excess heat.

		Energy outputs	
Micro-CHP power/heat	If $e^{load} < E_{max}^{chp}$	$e^{chp} = e^{load}$	$h^{chp} = HPR \cdot e^{chp}$
	If $e^{load} > E_{max}^{chp}$	$e^{chp} = E_{max}^{chp}$	
Supplemental/Excess power	If $e^{load} < e^{chp}$	$e^{imp} = 0$	$e^{exp} = 0$
	If $e^{load} > e^{chp}$	$e^{imp} = e^{load} - e^{chp}$	$e^{exp} = 0$
Supplemental/Excess heat	If $h^{load} < h^{chp}$	$h^{aux} = 0$	$h^{waste} = h^{chp} - h^{load}$
	If $h^{load} > h^{chp}$	$h^{aux} = h^{load} - h^{chp}$	$h^{waste} = 0$

Table 4.3-4: Electricity-led operation solution

Looking at the conditions we note that, for low energy heat conditions, if the electricity import price is higher than the micro-CHP electric marginal cost, then it is more convenient to generate electricity. For high energy heat load conditions, if the import price is higher than the micro-CHP electric marginal cost (after heat savings), then it is more convenient to generate electricity as well. Since the buy-back rate is low, there is no incentive to export electricity and the micro-CHP generates up to the level of the electricity load.

4.3.1.3. Heat-led operation

As with the previous solution, we find two sets of conditions for an optimal heat-led operation (shown in Table 4.3-5):

	Condition 1	**Condition 2**
Electricity prices	$\frac{P^{\$f}}{\eta_e^{chp}} > P^{\$e\_imp} > \left(\frac{P^{\$f}}{\eta_e^{chp}} - HPR \cdot \frac{P^{\$f}}{\eta_{th}^{aux}}\right)$ $P^{\$e\_imp} > P^{\$e\_exp}$	$\frac{P^{\$f}}{\eta_e^{chp}} > P^{\$e\_exp} > \left(\frac{P^{\$f}}{\eta_e^{chp}} - HPR \cdot \frac{P^{\$f}}{\eta_{th}^{aux}}\right)$ $P^{\$e\_imp} > P^{\$e\_exp}$
Micro-CHP HPR	$HPR > \frac{h^{load}}{e^{load}}$	$HPR < \frac{h^{load}}{e^{load}}$

Table 4.3-5: Conditions for optimum heat-led operation

In Table 4.3-6 we see the solution under any of these two conditions. Here, the micro-CHP tries to match the heat load if the machine has enough capacity, or else it runs up to its maximum heat capacity. The householder needs to generate additional heat if the load is larger than micro-CHP capacity. Excess of heat is not viable under this operation. Finally, the power output of the machine is a by-product and depending on the size of the electrical load, it may be possible to import or export power from/to the grid.

		Energy outputs	
Micro-CHP power/heat	If $h^{load} < H_{max}^{chp}$ If $h^{load} > H_{max}^{chp}$	$e^{chp} = h^{chp} / HPR$	$h^{chp} = h^{load}$ $h^{chp} = H_{max}^{chp}$
Supplemental/Excess power	If $e^{load} < e^{chp}$ If $e^{load} > e^{chp}$	$e^{imp} = 0$ $e^{imp} = e^{load} - e^{chp}$	$e^{exp} = e^{chp} - e^{load}$ $e^{exp} = 0$
Supplemental/Excess heat	If $h^{load} < h^{chp}$ If $h^{load} > h^{chp}$	$h^{aux} = 0$ $h^{aux} = h^{load} - h^{chp}$	$h^{waste} = 0$ $h^{waste} = 0$

Table 4.3-6: Heat-led operation solution

Here we note that, for any energy heat condition, if the import price is lower than the electric marginal cost but higher than the cost after savings from producing heat, then it is more convenient to generate heat. However, if the buy-back rate is attractive, then there is an incentive to export electricity. Therefore, the machine runs trying to match the heat load and, if possible, export when the power load is lower than the micro-CHP power output.

4.3.1.4. Base-load operation

The conditions for a least-cost base-load operation are shown in Table 4.3-7.

	Condition
Electricity prices	$P^{\$e\_imp} > P^{\$e\_\exp} > \frac{P^{\$f}}{\eta_e^{chp}}$
micro-CHP HPR	$HPR >$ or $< \frac{h^{load}}{e^{load}}$

Table 4.3-7: Conditions for optimum base-load operation

Table 4.3-8 shows the hourly energy outputs. Under these conditions, the micro-CHP operates flat at maximum capacity all the time. Depending on the size of the electricity or heat loads, the end-user may require either to import power or produce supplemental heat, or to export power or discard excess heat.

		Energy outputs	
Micro-CHP power/heat		$e^{chp} = E_{max}^{chp}$	$h^{chp} = H_{max}^{chp}$
Supplemental/Excess power	If $e^{load} < e^{chp}$	$e^{imp} = 0$	$e^{exp} = e^{chp} - e^{load}$
	If $e^{load} > e^{chp}$	$e^{imp} = e^{load} - e^{chp}$	$e^{exp} = 0$
Supplemental/Excess heat	If $h^{load} < h^{chp}$	$h^{aux} = 0$	$h^{waste} = h^{chp} - h^{load}$
	If $h^{load} > h^{chp}$	$h^{aux} = h^{load} - h^{chp}$	$h^{waste} = 0$

Table 4.3-8: Base-load operation solution

As the buy-back rate is higher than the electric marginal cost of operating the micro-CHP unit, there is an incentive to sell power to the grid. Therefore, the householder operates the machine at full capacity regardless of the load size and conditions.

4.3.1.5. Summary of analysis

Throughout this section we have analyzed a simplified version of the intelligent-control strategy based on cost optimization explained in Chapter 3. We find four possible outcomes for the micro-CHP depending on the energy load and energy price conditions: no operation, electricity-led operation, heat-led operation and base-load operation. Figure 4.3.1 shows a summary of the conditions for each of the operational outcomes, where $Price1 = \frac{P^{\$f}}{\eta_e^{chp}} - HPR \cdot \frac{P^{\$f}}{\eta_{th}^{aux}}$ represents the micro-CHP electric marginal cost after considering the savings from simultaneously producing heat, and $Price2 = \frac{P^{\$f}}{\eta_e^{chp}}$ represents the electric marginal costs of the machine from producing electricity-only.

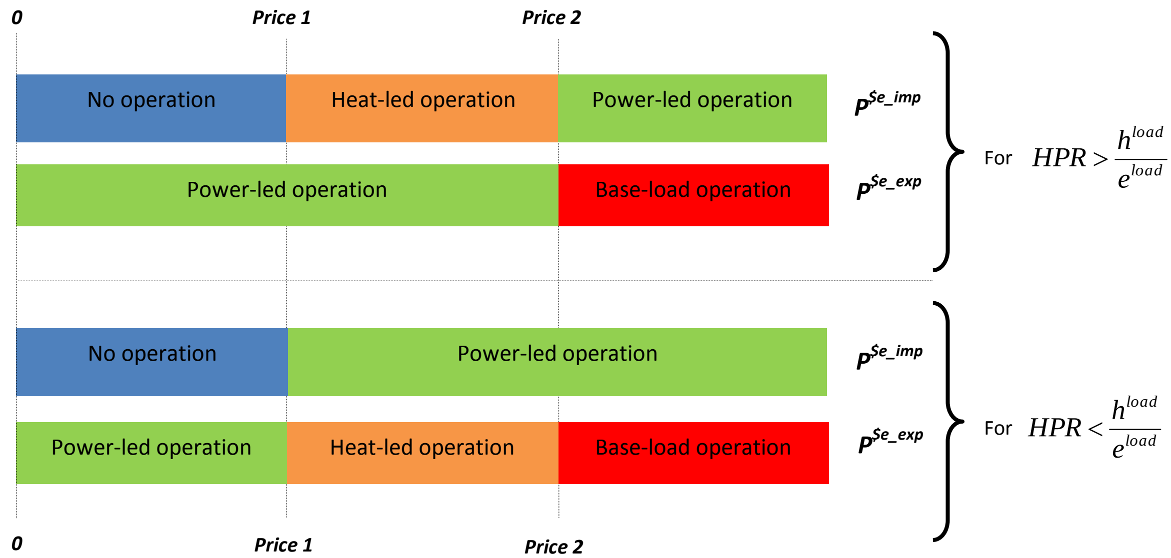

Figure 4.3.1: Micro-CHP operational outputs and conditions for Pse_imp > Pse_exp

In the above figure we can see that:

1. The micro-CHP does *not operate* if $P^{\$e\_imp} < Price1$, regardless of the load condition.
2. The micro-CHP operates at *full capacity* if $P^{\$e\_exp} > Price2$, regardless of the load condition.
3. The micro-CHP has a *heat-led operation* if:
   - $HPR > \frac{h^{load}}{e^{load}}$ and $Price1 < P^{\$e\_imp} < Price2$, or
   - $HPR < \frac{h^{load}}{e^{load}}$ and $Price1 < P^{\$e\_exp} < Price2$
4. Finally, the micro-CHP has a *power-led operation* if:
   - $HPR > \frac{h^{load}}{e^{load}}$, $Price2 < P^{\$e\_imp}$ and $P^{\$e\_exp} < Price2$, or
   - $HPR < \frac{h^{load}}{e^{load}}$, $Price1 < P^{\$e\_imp}$ and $P^{\$e\_exp} < Price1$

In the following section we illustrate through some quantitative cases, how the intelligent-control model's results change when we vary the micro-CHP HPR and energy prices.

4.3.2. Quantitative results

We have seen that energy and price conditions affect the operational outcome of the micro-CHP unit. In this section, we review those conditions based on the datasets we used in Chapter 3[73].

In Figure 4.3.2 we can see the relationship between energy loads and the micro-CHP HPR for low and medium values. The blue points represent the ratio $\frac{h^{load}}{e^{load}}$ and whether it is above or below the $HPR_{micro\text{-}CHP}$. Thus, we note that for low values more data points are above the $HPR_{micro\text{-}CHP}$ line (see green line) than for the case with a medium value (see red line).

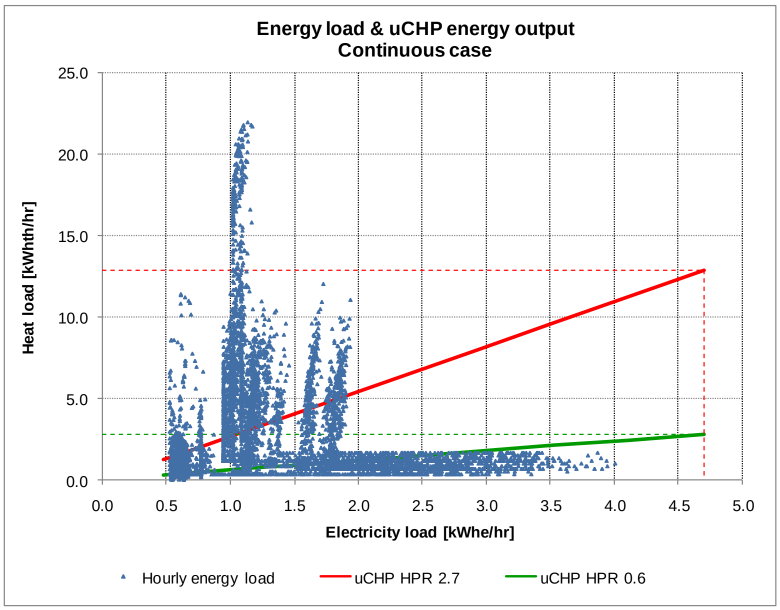

Figure 4.3.2: : Hourly electricity load vs. heat load

Red line depicts a medium micro-CHP HPR of 2.7. Green line depicts a low micro-CHP HPR of 0.6. Blue dots depict energy load

As we saw, the operational outcomes of the least-cost model depends on knowing, not only the energy load conditions, but also the relationship between the electricity import and export prices with the fuel price. Figure 4.3.3 illustrates this relationship for a *medium* $HPR_{micro\text{-}CHP}$, where we observe that the entire set of hourly electricity prices for the year are clustered between *Price1* and *Price2*, where:

1. $Price1 < P^{\$e\_imp} < Price2$, and
2. $Price1 < P^{\$e\_exp} < Price2$

[73] Recall that for the energy loads, we used an energy simulator for generating hourly electricity and heat profiles for a particular house located in Boston. In addition, for energy prices we took the historical utility rates for natural gas and electricity, and for buy-back rates we assumed a value 1¢/kWh less than the retail rate (refer to Chapter 3).

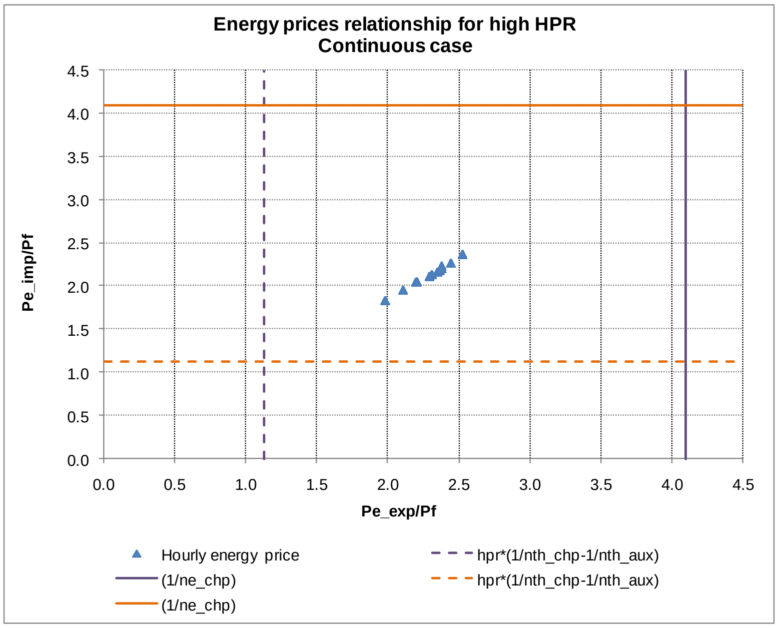

Figure 4.3.3: Energy price relationship for high HPR

Dash lines show the ratio Price1 to Pf. Solid lines show the ratio Price2 to Pf. Blue dots depict price relationship

Therefore, *for the micro-CHP with HPR2.7 and the particular price conditions, the least-cost model results in a heat-led operation for the entire year*.

If we do the same analysis for a *low* $HPR_{micro\text{-}CHP}$, we note how the electricity prices move beyond *Price2* (see Figure 4.3.4).

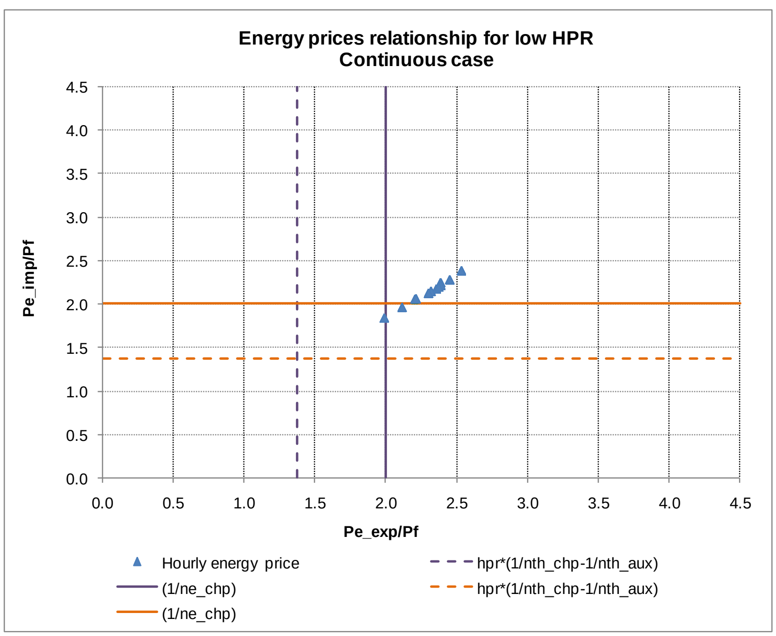

Figure 4.3.4: Energy price relationship for low HPR

Dash lines show the ratio Price1 to Pf. Solid lines show the ratio Price2 to Pf. Blue dots depict price relationship

Therefore, *for a micro-CHP with HPR0.6 and the assumed conditions, the least-cost model results in base-load operation most of the time.*

In the following section we review some numerical results when varying price conditions, for medium and low values of the micro-CHP HPR.

4.3.1.6. Results for medium HPR

Taking the least-cost formulation, we work with the case where the technology has medium HPR2.7, i.e. characteristic of internal combustion engines based micro-CHP units. We run four cases where we use the same retails rates for gas and electricity purchase, and different electricity buy-back rates.

In Figure 4.3.5 we see the hourly energy price conditions assumed for the simulations for the entire year, and the price relationships defined as *Price1* and *Price2,* which depend on the fuel price, and the efficiency values of the micro-CHP and furnace. In addition, we depict the hours of the year when the load ratio ($\frac{h^{load}}{e^{load}}$) is larger or not than the $HPR_{\text{micro-CHP}}$, where clearly we see that the electric load component in summer is large.

The buy-back rates used for the cases are:

- $P^{\$e\_exp}$: reference buy-back rate, 1¢/kWh cheaper than the retail import price.
- $P^{\$e\_exp\_Price1+}$: buy-back rate slightly higher than the defined Price1.
- $P^{\$e\_exp\_Price1-}$: buy-back rate slightly lower than the defined Price1.
- $P^{\$e\_exp\_0}$: buy-back rate with a flat value of 0$/kWh.

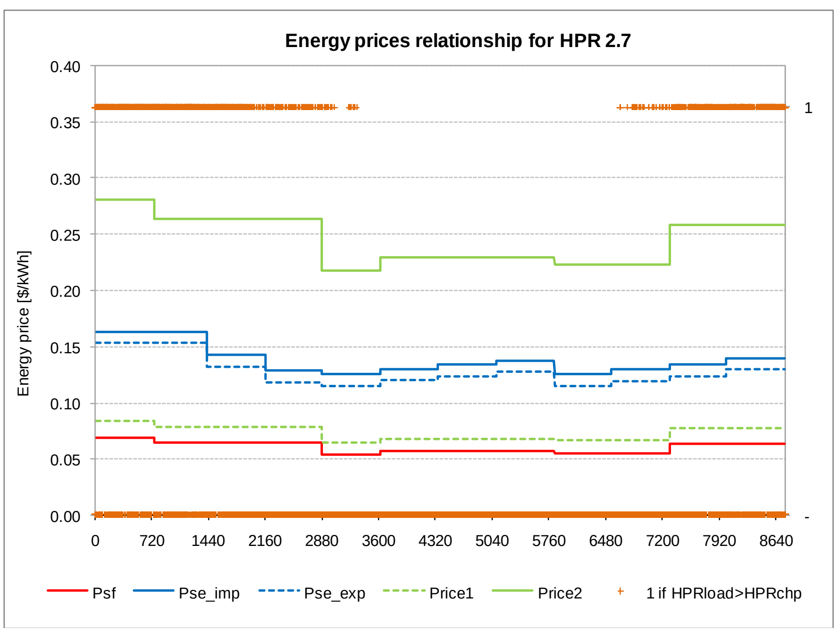

Figure 4.3.5: Energy prices for medium HPR case.
Red line shows the gas prices, P$f. Blue line shows the electricity import price, P$e_imp.
Dash blue line shows the reference export price, P$e_exp. Green lines show Price1 and Price2 for medium HPR.
Top orange dots illustrate when load ratio is larger than the HPR. Bottom orange dots show when load ratio is smaller than the HPR.

Results of the cases are shown in tables below. In terms of physical outputs we note that:

1. Cases with $P^{\$e\_exp}$ and $P^{\$e\_exp\_Price1+}$ have the same results. The price conditions for both cases are $Price1 < P^{\$e\_imp} < Price2$ and $Price1 < P^{\$e\_exp} < Price2$, which means that the micro-CHP has a heat-led operation regardless of the load condition.

Cases	*Import power* [kwh/yr]	*Export power* [kwh/yr]	*Chp power* [kwh/yr]	*Chp net power** [kwh/yr]
Pe_exp	5,936	(3,444)	8,697	5,253
Pe_exp_Price1+	5,936	(3,444)	8,697	5,253
Pe_exp_Price1-	5,936	-	5,253	5,253
Pe_exp_0	5,936	-	5,253	5,253

Table 4.3-9: Annual power imports, micro-chp electric power and electricity surplus exported back the grid for medium HPR

2. Cases with $P^{\$e\_exp\_Price1-}$ and $P^{\$e\_exp\_0}$ are also the same. The price conditions for both cases are $Price1 < P^{\$e\_imp} < Price2$ and $P^{\$e\_exp} < Price1$, which depending on the load ratio condition means that the micro-CHP has a heat-led or power-led operation. Under the power-led operation there is no export of electricity, and under the heat-led operation that may be possible. However, because of the price conditions, heat-led operation is possible only if $HPR > \frac{h^{load}}{e^{load}}$. This condition does not happen during summer, and in winter it is possible only in hours with a low thermal load.

Cases	*Supplemental heat* [kwh/yr]	*Excess heat* [kwh/yr]	*Chp heat* [kwh/yr]	*Chp net heat** [kwh/yr]
Pe_exp	943	-	23,810	23,810
Pe_exp_Price1+	943	-	23,810	23,810
Pe_exp_Price1-	10,372	-	14,381	14,381
Pe_exp_0	10,372	-	14,381	14,381

Table 4.3-10: Annual supplemental heat, micro-chp heat and excess heat for medium HPR

In terms of annual energy costs we see that, with medium HPR results are similar with a difference of less than 10%. However, it is interesting to note that with a high buy-back rate ($P^{\$e\_exp}$) and a much lower rate ($P^{\$e\_exp\_Price1+}$) we obtain the same operational behavior. Moreover, if the price is marginally lower ($P^{\$e\_exp\_Price1-}$) then the micro-CHP does not have incentives to export electricity (refer to Figure 4.3.5 above).

Cases	*Energy cost* [$/yr]
Pe_exp	2,624
Pe_exp_Price1+	2,828
Pe_exp_Price1-	2,832
Pe_exp_0	2,832

Table 4.3-11: Annual energy costs for medium HPR

Therefore, for the process of setting up buy-back rates it is important to know the type of technology being in place in the grid. Under this *simplified model, we realized that the export price does not have to be extremely high to encourage power exports to the grid if the technology has a medium HPR.*

4.3.1.7. *Results for low HPR*

In a similar analysis, we simulate the case where the technology has a low HPR0.6. We run five cases where, as before, we use the same electricity and gas retail rates and different buy-back rates.

Figure 4.3.6 shows the prices assumed for the simulations for the whole year. Here, we see here that the price relationships defined as *Price1* and *Price2* are different from the case with medium HPR, as these terms depend not only on the fuel price, but also the efficiency of the micro-CHP unit. Compared to the previous case, we note that the value of *Price2* has significantly decreased (see solid green line in figure). Also we note that the energy load ratio is larger than the $HPR_{micro\text{-}CHP}$ during the summer, whereas in the previous case this condition was not feasible.

The buy-back rates we used for the cases were:

- $P^{\$e\_exp}$: reference buy-back rate, 1¢/kWh cheaper than the retail import price.
- $P^{\$e\_exp\_Price2-}$: buy-back rate slightly lower than the defined Price2.
- $P^{\$e\_exp\_Price1+}$: buy-back rate slightly higher than the defined Price1.
- $P^{\$e\_exp\_Price1-}$: buy-back rate slightly lower than the defined Price1.
- $P^{\$e\_exp\_0}$: buy-back rate with a flat value of 0$/kWh.

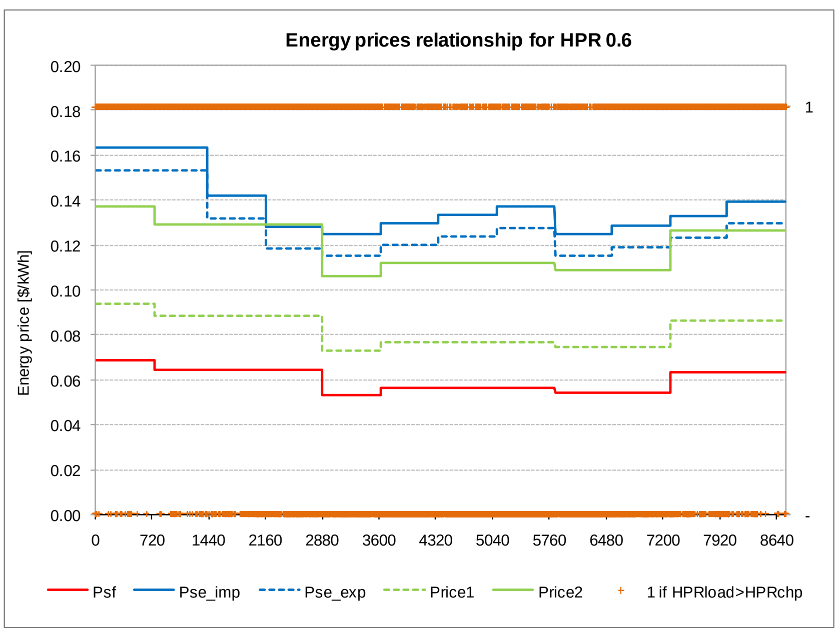

Figure 4.3.6: Energy prices for low HPR case.

Red line shows the gas prices, P$f. Blue line shows the electricity import price, P$e_imp.

Dash blue line shows the reference export price, P$e_exp. Green lines show Price1 and Price2 for high HPR.

Top orange dots illustrate when load ratio is larger than the HPR. Bottom orange dots show when the ratio is smaller than the HPR.

Results are shown in tables below. In terms of physical outputs we note that:

1. The case with $P^{\$e\_exp}$ has the largest power export output. The price conditions for most of the year are $Price2 < P^{\$e\_imp}$ and $Price2 < P^{\$e\_exp}$, which results in the micro-CHP operating as base-load regardless of the load ratio condition.

Cases	*Import power* [kwh/yr]	*Export power* [kwh/yr]	*Chp power* [kwh/yr]	*Chp net power** [kwh/yr]
Pe_exp	13	(27,499)	38,675	11,176
Pe_exp_Price2-	13	(12,417)	23,593	11,176
Pe_exp_Price1+	13	(12,417)	23,593	11,176
Pe_exp_Price1-	13	-	11,176	11,176
Pe_exp_0	13	-	11,176	11,176

Table 4.3-12: Annual power imports, micro-chp electric power and electricity surplus exported back the grid for low HPR

2. Cases with $P^{\$e\_exp\_Price2-}$ and $P^{\$e\_exp\_Price1+}$ have the same results. The price conditions for both cases are $Price2 < P^{\$e\_imp}$ and $Price1 < P^{\$e\_exp} < Price2$, which means that the micro-CHP has a power-led and heat-led operations depending on the load condition. It may be possible to have excess of electric power and heat.

Cases	*Supplemental heat* [kwh/yr]	*Excess heat* [kwh/yr]	*Chp heat* [kwh/yr]	*Chp net heat** [kwh/yr]
Pe_exp	11,441	(9,893)	23,205	13,312
Pe_exp_Price2-	11,441	(844)	14,156	13,312
Pe_exp_Price1+	11,441	(844)	14,156	13,312
Pe_exp_Price1-	18,891	(844)	6,706	5,861
Pe_exp_0	18,891	(844)	6,706	5,861

Table 4.3-13: Annual supplemental heat, micro-chp heat and excess heat for low HPR

3. Cases with $P^{\$e\_exp\_Price1-}$ and $P^{\$e\_exp\_0}$ are also the same. The price conditions for both cases are $Price2 < P^{\$e\_imp}$ and $Price1 < P^{\$e\_exp}$, which means that the micro-CHP unit has a power-led operation regardless of the load ratio condition. Under these conditions, exports of electricity are not possible.

In terms of annual energy costs we note that, results with low HPR may be dissimilar as shown in Table 4.3-14. It is interesting to observe that a high export price encourages operating the machine at full capacity with lots of excess heat. However, if the price goes slightly below the defined Price2, the micro-CHP operational behavior changes drastically with substantial less time running at full capacity (see Table 4.3-15 below). We also have that the additional cost savings of the case with $P^{\$e\_exp\_Price2-}$ are merely better to the case with $P^{\$e\_exp\_Price1+}$, as the operational outputs in both cases are the same.

Cases	*Energy cost* [$/yr]
Pe_exp	1,868
Pe_exp_Price2-	2,134
Pe_exp_Price1+	2,597
Pe_exp_Price1-	2,609
Pe_exp_0	2,609

Table 4.3-14: Annual energy costs for low HPR

	Hours of operation				Hours of operation		
	Chp = 0kWe	0 < Chp < 4.7 kWe	Chp = 4.7kWe		Chp = 0kWe	0 < Chp < 4.7 kWe	Chp = 4.7kWe
Jan	-	-	744	Jan	-	104	640
Feb	-	-	672	Feb	-	144	528
Mar	-	-	744	Mar	-	277	467
Apr	-	504	216	Apr	-	504	216
May	-	-	744	May	-	712	32
Jun	-	-	720	Jun	-	720	-
Jul	-	-	744	Jul	-	744	-
Aug	-	-	744	Aug	-	744	-
Sep	-	-	720	Sep	-	720	-
Oct	-	-	744	Oct	-	701	43
Nov	-	323	397	Nov	-	323	397
Dec	-	-	744	Dec	-	201	543
Total	**-**	**827**	**7,933**	**Total**	**-**	**5,894**	**2,866**

Table 4.3-15: Monthly micro-CHP operational hours for different output levels. Case with Pe_exp vs. Case with Pe_exp_price2- for low HPR

As with previous case, we realized that for determining the buy-back rates it is important to know the micro-CHP technology being in place. Using the intelligent-control strategy for the low HPR-based micro-CHP, we learned that micro-CHP machine changes its operational behavior to favor more exports of power, despite the excess heat being produced.

4.4. Summary

Several results have been shown throughout this chapter to try to understand the operation of micro-CHPs under various conditions. The analyses focused on the local results, looking at the micro-CHP impacts at residential level only.

First, we found that the *incorporation of a hot water storage unit* increases the micro-CHP benefits to householders in comparison to heating systems based on forced warm-air configurations. In general, annual energy costs are reduced, energy efficiency is increased, and CO2 emissions are decreased. We observed that the storage of heat gives the system more flexibility for meeting local thermal demands, allowing a more efficient use of the heat produced by the micro-CHP unit. These results are more apparent for technologies with medium HPR. For a micro-CHP with low HPR, because of the price conditions, the machine continuously operates regardless of having or not a buffer tank. Finally, because of the discrete operation of the micro-CHP, it was difficult to observe if the addition of a buffer tank resulted in a more regular or smoother operation (attractive feature for manufacturers wishing to commercialize micro-CHP units).

Second, we observed that a continuous micro-CHP operation - as opposed to a discrete operation - also increases the benefits to residential customers. As the machine is assumed to continuously adjust to the local energy requirements, there is an increase of the micro-CHP capacity factor, and there is no production of excess heat. This finding is quite interesting keeping in mind that currently several manufacturers are working towards developing micro-CHPs with modulating capability.

Third, we explored the effects of having different levels of stored heat in the buffer tank at the end of the day. We found that the stored heat levels have a marginal impact on the benefits, in particular for tanks of small size which it is the case being studied in this thesis.

Fourth, in the last section we explored the sensitivity of micro-CHPs to energy prices. As the control strategy is based on a least-cost operation, we found that micro-CHPs can react in different ways depending on the electricity prices passed to residential customers, the energy load conditions and the micro-CHP technology itself. On one hand we found that, for the particular price and load conditions, the micro-CHP with medium HPR is less sensitive to electricity prices and tend to operate following the local heat load (if there is a buy-back rate). On the other hand, the micro-CHP with low HPR seems more sensitive to prices and the machine tends to operate either at full capacity or following the electric power load. The economic incentives are perceived differently by a micro-CHP with low HPR, as this machine tries to avoid buying expensive electricity to the grid.

Although we analyze this topic in detail Chapter 6, we need to mention that the cost-based operational pattern of the micro-CHP depends very much on the valuation given to the electricity produced by the micro-CHP. For example we noted that when the electricity retail price is higher than the micro-CHP electric-only marginal cost, then the machine tends to follow the electric load with the purpose of avoiding getting expensive electricity from the grid. On the opposite side, when the retail price is lower than the micro-CHP marginal cost after considering the savings from producing heat simultaneously, then the machine does not operate, as clearly it is more cost-effective to buy power and produce heat separately.

Finally, we also explored the effects of giving a buy-back rate for any on-site surplus of electricity. We realized that:

- It may have a distortive effect and result in an inefficient micro-CHP operation. For example, if the buy-back rate is high, the production of electricity by micro-CHP becomes very attractive to residential customers for the potential revenues for the electricity sales. They try to operate their machines at full capacity, regardless of the local heat requirements, increasing the amount of excess heat especially in summer when the heat load is small.
- The rate does not have to be extremely high to encourage exports to the grid, especially for micro-CHPs with low HPR.

Therefore, a production subsidy in the form of a buy-back rate impacts the operation of micro-CHPs using an intelligent-control strategy. Micro-CHPs may favor electricity production, where heat production becomes a secondary activity. Depending on the technology, this change in the micro-CHP operation may increase costs, increase excess heat, and decrease the efficiency of the system.

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CHAPTER 5

LARGE-SCALE DEPLOYMENT MODELS OF MICRO-CHPS WITHIN AN ENERGY SYSTEM

System efficiency of micro-CHPs in principle makes them an attractive technology for meeting near-future energy requirements in a sustainable manner. However, increasing levels of penetration require a more complex analysis that goes beyond individual economic benefits. The effects of micro-CHPs when deployed at large-scale calls for understanding not only the value to individual householders as explained in Chapters 3 and 4, but also to the electric power system they are embedded in and the entire energy model. The benefits of micro-CHPs versus conventional heating systems, from the household's point of view will vary depending on several factors, such as the incorporation of heat storage possibilities, conversion technology adopted, control strategy and pricing regimes. From a system's perspective, the value of micro-CHPs will depend on their integration into the electrical system in terms of the technical and ICT infrastructures, physical operation, market and regulatory structures.

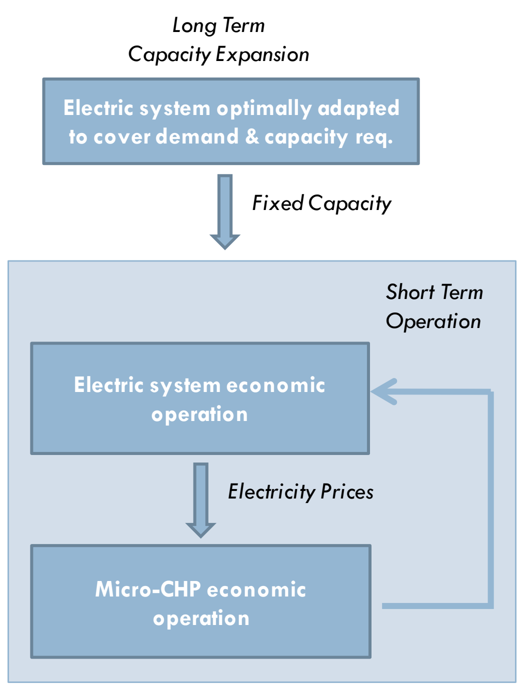


Figure 5. 1: System integrative approach

As we have mentioned, our research does not focus on the technical and implementation challenges needed to allow an efficient integration of a large number of distributed generation in the electric power system. The formulation and consequent analyses focus on the potential value of micro-CHPs to residential users and the electrical system from an economic and regulatory approach. This approach is based on an integrative methodology that combines, on one hand, a generation capacity expansion process in an electric power system and, on the other hand, the economic operation of conventional power plants and a large number of micro-CHPs integrated to it (see Figure 5. 1).

Under this framework, it is explored (i) long-term effects such as generation capacity displaced by micro-CHPs and related investment costs, (ii) short-term impacts of increasing levels of micro-CHPs in electricity operational costs, CO2 emissions, peak demand and short term energy prices. In addition, we examine the value of micro-CHPs under different economic signals sent to final customers in the form of electricity and natural gas prices, and feed-in tariff for the electricity produced by micro-CHPs.

Finally, the goal in Chapters 5 and 6 is to understand the value of micro-CHPs from a system's point of view that may later be used to inform future public policies and regulatory support intended to promote this technology as one more helpful measure in a carbon constrained world[74] (see "Appendix B.1. Glossary of terms").

5.1. Short-term operational model

In the short-term operation realm, the electric power system is characterized by an energy portfolio derived from a long-term decision making process, where the system has been adapting through the years to increasing levels of micro-CHPs (described in the following section). While keeping the generating capacity fixed for that year, conventional power plants along with micro-CHPs are allowed to operate efficiently to meet the system electric demand and the heat requirements for the fraction of householders being analyzed.

The main goals from this analysis are to understand:

- Effects on the electric production by different technologies, particularly examine the type of generation being displaced and the level of load reduction during peak times.
- Impacts on CO2 emissions at a system level considering emissions from conventional plants, micro-CHPs, and conventional heating systems used for meeting electricity and heat demand.
- Short-term economic effects measured as variations in the economic welfare, electricity production costs, and payback period to micro-CHP owners.

[74] Thanks to Andrés Ramos for his support in developing both Short-term operational model and Long-term generation expansion model. Andrés Ramos is Full Professor at the Departamento de Organización Industrial, Instituto de Investigación Tecnológica (IIT), Escuela Técnica Superior de Ingeniería (ICAI), Universidad Pontificia Comillas.

- Overall effect of having better information[75], where customers under a flat rate design see the same energy rate for the entire year, customers with a time-of-use rate design receive a differentiated rate per season and per peak or off-peak hours of the day, and customers under a real-time rate scheme get a price of electricity that will change for each hour of the day. Based on hourly short-term marginal prices of electricity, we explore how results and the value of micro-CHPs change when having these different retail pricing schemes.

5.1.1. Methodology description

From a system/central regulatory approach, we aim at determining the most efficient operation of a set of power plants when a large number of micro-CHPs is in the system. Based on the electrical system's hourly marginal prices, end-users owning micro-CHPs decide the most economic operation of the machines for meeting their heat and electricity requirements.

The methodology considers:

- A short-term scope, i.e. one year time horizon for the analysis.
- Hourly annual electric demand forecast for a system with similar characteristics to the New England region.
- Hourly annual electric and heat demand simulations for two classes of customers.
- Hourly short-term power reserve requirements.
- Generation technologies characterized by conventional power plants and distributed generation in the form of micro-CHPs and conventional heating systems.
- Fixed installed capacity of the technology mix for the year under analysis.
- Environmental regulations.

The methodology does not consider the transmission network. The representation is based on a single node at the distribution level. In addition, ramp-up and ramp-down times are not included in the formulation.

As mentioned, the system approach of the problem is expected to provide information that will help to understand future regulatory decisions intended to promote micro-CHPs as an alternative for meeting energy in the short term. In particular, we expect to get the following quantitative results:

[75] And potentially more transparent information, more accurate measurement and better control capabilities.

a. Operational outputs:

- Power plants electric production for each hour of the year.
- Micro-CHPs electric and heat production for each hour of the year.
- Peak demand reduction.
- CO2 emissions per technology.
- Energy efficiency.

b. Economic outputs:

- System operational costs.
- Short-term marginal prices.
- Energy costs at residential level.
- Impacts on economic social welfare.

In this chapter we describe in detail the methodology used for analyzing the short-term problem. In general, we can say that the problem is based on an iterative routine that integrates two optimization modules (see Figure 5.1.1):

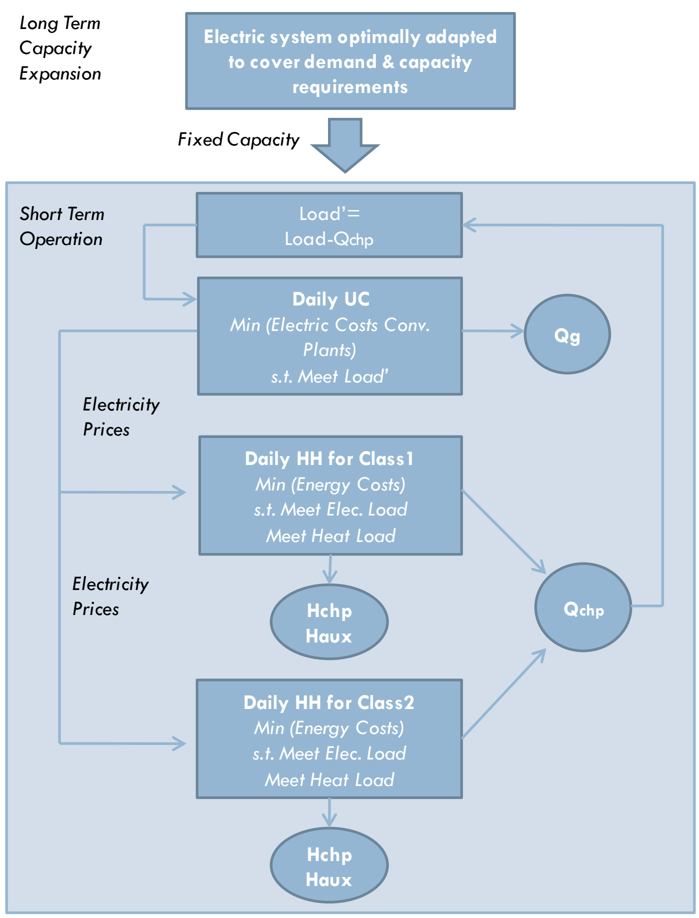


Figure 5.1.1: Short-term iterative process

- The first module is a simple unit commitment (UC) problem used for representing the short-term operation of an electric power system at the wholesale level, considering no-load and start-up costs in addition to variable costs. The electricity load (*Load'*) to meet in this formulation is the system's load (*Load*) reduced by the electricity production from the micro-CHPs coming from the second module (Q_{chp}).

- The second module is a decentralized intelligent control model at the household level (HH for Class) for each class of customer, where the electricity generated by the micro-CHP units (Q_{chp}) is feedback into the UC module. Optimal heat production by micro-CHPs (H_{chp}) and conventional heating units (H_{aux}) are also obtained from this module.

An iterative process is done with the purpose of determining the final system's short-term marginal prices[76], given the electricity production by conventional power plants (Q_g) and the aggregated electricity production from micro-CHPs (Q_{chp}). Electricity prices are passed to final customers who decide the least-cost operation of their micro-CHPs, while the annual system load (*Load*) is adjusted after taking into account the electric generation from these micro-CHPs (*Load'*).

Finally, for the formulation of the short-term problem we assume an intelligent control strategy for micro-CHPs, where the units are able to respond to energy price variations. In Chapters 3 and 4 we showed that the largest positive outcomes for individual householders are achieved using this particular control strategy.

5.1.2. Problem formulation

5.1.2.1. Unit Commitment formulation

The first module of the problem is a simplified unit commitment (UC) model, where the objective is to find the minimum cost of scheduling a set of thermal conventional generating units over a period of study of one year. Besides the basic restrictions of meeting the system electrical demand, there are technical and regulatory constraints in addition to supplying an adequate level of reliability (see Appendix B.1. Glossary of terms).

From this UC model, we expect to get results for the period being analyzed such as:

a. Physical operation:

  - Start-up and shut-down decisions for each day of the year.
  - Hourly dispatch of the power plants.

[76] Among other results, such as optimal patterns of production with micro-CHPs.

- CO_2 emissions.

b. Economic outputs:

- Production costs.
- Hourly electricity marginal prices.

Finally, the UC problem is solved through mixed integer linear (MIP) programming. We use GAMS/CPLEX and a MATLAB-GAMS interface called MATGAMS (79)[77].

Time structure

We consider a time horizon of one year subdivided in 365 days (a short term scope). Commitment decisions are made for the 24 hours of the day (for example from 1am to 12pm), for every day of the year.

Assumptions

To make the problem manageable, we made some assumptions and simplifications while keeping the essential features of the power system behavior:

- As this is a short-term problem, time is represented by hourly periods in chronological order (we do not use simplifications like load duration curves).
- The electric system includes only thermal power plants. They can start up and shut down during the day, but some coal and nuclear units are committed at the beginning of the day.
- No ramp rates or shut-down costs are included.
- Installed capacity of the electrical system is previously defined by a long-term generation capacity expansion planning. Investment decisions are kept fixed during the year of analysis.
- The formulation is based on a deterministic approach.

[77] Documentation: Mathematical Programming Technical Report 98-19, November 1998 available at http://pages.cs.wisc.edu/~ferris/matlab.html.

Inputs

Before describing the mathematical formulation, we will review the main data and parameters required by the model, as well as the notation used.

a. Electric demand and micro-CHP generation for every day:

Hourly demand for a particular year of analysis is based on the ISO-NE historical demand for year 2007 (80). Total electric consumption for that year was about 135[TWh/yr], a maximum demand of 26,145[MW/yr], and average demand of about 15,350[MW/yr][78].

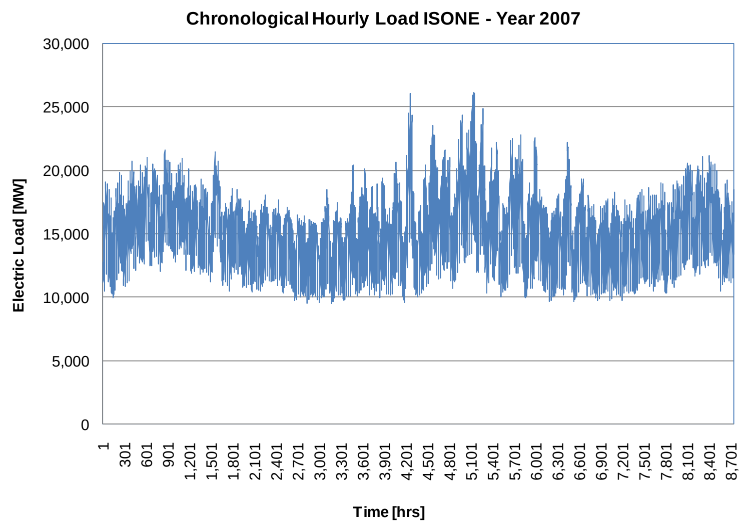


Figure 5.1.2: ISO-NE hourly electric load for year 2007

We use a chronological load curve for the entire system, where a constant annual growth rate[79] is applied every year until the last year of the time horizon:

Hourly system electric demand for every day [MW]: $d_{d,h}$

Annual demand growth rate [p.u.]: gr_y

As we explain in more detail later, the UC module is integrated with the HH module that optimizes the operation of micro-CHPs at the residential level. As a consequence, the electric demand that the UC module needs for deciding the operation of the thermal plants has to consider the aggregated electric production from micro-CHPs. The demand is modified to a new *reduced demand* that subtracts the micro-CHP electric generation ($q_{d,h,chp}$) from the system electric demand:

$$d'_{d,h} = d_{d,h} \cdot (1 + gr_y)^y - q_{d,h,chp}$$

[78] For electric demand we use ISO-NE's SYSLoad (ISO_NE Control Area), which it is the actual system load in MW as determined by metering for each load zone and the entire New England system. The system load is used for day-ahead & long-term forecasting and reporting purposes.
[79] Electricity demand growth is based on the EIA Energy Outlook 2009 for the Northeast Power Coordinating Council / New England area. An average demand increment for the period 2008 and 2035 (based on total sales) is provided for three cases:

- Reference case with 1.0188% per year,
- High growth case with 1.3369% per year, and
- Low growth case with 0.6857% per year.

We need to clarify that $q_{d,h,chp}$ is a decision variable in the HH model. However, $q_{d,h,chp}$ is not a decision variable in the UC model, but rather it is an exogenous input that modifies the electric demand in the formulation.

b. Characteristics of thermal technologies:

Within the technology portfolio, we consider a wide range of thermo-electric generators[80]. Technical and economic characteristics of the plants are based on data used in the EIA's Annual Energy Outlook 2010 (AEO2010) (81) and other sources[81]. For each technology, we include the following technical characteristics[82]:

Maximum output [MW]: $\overline{p}_g$

Minimum output [MW]: $\underline{p}_g$

Availability factor[83] [p.u.]: af_g

Heat rate [MMBtu/MWh]: hr_g

Regarding their economic characteristics, we include:

Fuel cost[84] [$/MMBtu]: f_g

Operation & maintenance (O&M) variable cost [$/MWh]: vom_g

No load cost[85,86] [$/h]: nl_g

---

[80] To make the problem formulation simpler, we did not include renewable technologies. One of the limitations of this simplification is the inability to assess their environmental benefits in a scenario with potentially large penetration of micro-CHPs.

[81] In addition, we included some characteristics from NREL's regional Energy Deployment System (ReEDS) model for year 2005 (109). However, in the short-term analysis we did not include investment costs as we dealt with operational production decisions only.

[82] We do not include ramp rate times for the thermal units.

[83] Availability factor considers both forced and unforced outage rates according to typical technologies assumed in Documentation of ReEDS Base Case Data: Table 16 (109).

[84] Fuel prices adopted in the ST model were taken from Annual Energy Outlook 2010 (93) for energy prices for the Electric Power Sector and Residential Sector in New England for year 2007 contained in "Table 11: Energy Prices by Sector and Source" in the Reference case. Prices in the report are expressed in 2008 dollars, which were converted to 2007 dollars using the Consumer Price Index (106). Thus, the prices for the initial year of the study time are the following:

- Distillate fuel oil: 14.9872 [$2007/MMBtu]
- Natural Gas: 7.7196 [$2007/MMBtu]
- Steam Coal: 2.9568 [$2007/MMBtu]
- Residential Natural Gas: 16.0670 [$2007/MMBtu]

[85] The no-load cost term is derived from the fuel cost function normally adopted in short-term operating models. The fuel cost function is assumed to be convex quadratic for conventional power units. This is derived from the Input-Output curve, which represents the required energy input to sustain a specified power output *Pg* at some hour: $F(P_g) = \alpha + \beta \cdot P_g + \gamma \cdot P_g^2$ [MMBtu/h].

When this curve is multiplied by the fuel price, it is obtained the cost of the fuel used by a generator to supply *Pg* units of power output: $C(P_g) = \alpha' + \beta' \cdot P_g + \gamma' \cdot P_g^2$ [$/h].

Startup cost[87,88] [$]: su_g

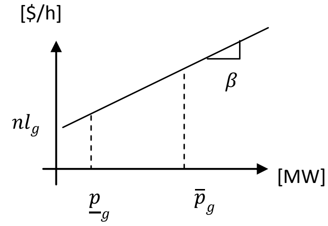
In Table 5.1-1, we can see the main characteristics of the plants grouped according to technology type:

g		af_g [p.u.]	hr_g [MMBtu/MWh]	f_g [$/MMBtu]	ef_g [ton/MMBtu]	vom_g [$/MWh]	nl_g [$/h]	su_g [$]	vc_g [89] [$/kWh]
GasCT	n1	0.88	10.788	7.720	0.0553	3.52	2,145	18,766	0.087
GasCC	n2	0.87	7.196	7.720	0.0553	2.03	2,172	21,715	0.058
GasCCS	n3	0.87	8.613	7.720	0.0055	2.90	2,172	21,715	0.069
CoalOldUns	n4	0.85	9.200	2.957	0.0926	5.24	161	21,447	0.032
CoalOldScr	n5	0.85	9.200	2.957	0.0926	4.52	161	21,447	0.032
CofireOld	n6	0.85	9.200	2.957	0.0926	4.52	161	21,447	0.032
CoalNew	n7	0.85	8.712	2.957	0.0926	1.95	161	21,447	0.028
CofireNew	n8	0.85	8.712	2.957	0.0926	1.95	161	21,447	0.028
CoalIGCC	n9	0.85	8.765	2.957	0.0926	2.88	161	21,447	0.029
CoalCCS	n10	0.85	10.781	2.957	0.0093	4.37	161	21,447	0.036
OGS	n11	0.78	9.230	14.987	0.0780	3.83	2,413	29,490	0.142
Nuclear	n12	0.88	10.488	0.670	-	0.49	-	1,085, 755	0.008

Table 5.1-1: Thermal technology characteristics

We need to clarify that from the long-term expansion model we obtain the installed capacity of an energy portfolio that considers 12 thermo-electric technologies[90].

Furthermore, when the fuel cost curve is linearized and technical constraints are taken into account, the following linear representation is obtained:



Where nl_g is the point where the generator ideally runs at zero power output (82),(110). This amount is paid to those units that are committed (on-line) to operate in the electric system.

[86] No load cost and startup costs were provided by researchers at the Institute for Research in Technology of Comillas University (Madrid, Spain). These values represent only cost samples for some particular technologies, and further research should be done if more realistic values want to be used in the analysis.

[87] See footnote #86.

[88] Startup cost reflects the fuel consumption needed to reach the optimal conditions to start a generator. The longer the unit has been shut down, the more expensive the cost is as the boiler needs to reach suitable pressure and temperature conditions. In this formulation, this term is simplified and assumed to be a constant cost whenever the start-up decision is made (82).

[89] For reference only, we have included in this table the total variable cost per electric generator vc_g is calculated here considering fuel prices f_g for year 2007, electric heat rate hr_g, and their variable O&M vom_g.

[90] The technologies being considered are:
n1: Natural gas combustion turbine (GasCT)
n2: Combined cycle gas turbine (GasCC)
n3: Combined cycle gas turbine with carbon capture and sequestration (GasCCS)
n4: Conventional pulverized coal steam plant - no SO2 scrubber (CoalOldUns)

From this outcome, we know how much installed capacity is required to meet both demand and reserve requirements for the year under analysis for each of these technologies. However, for the short-term analysis we need to represent a particular number of electric power units within each technology with a maximum output $\overline{p}_g$. The general simplification for determining the number of units within each technology will be adopting units of typical size[91]. In addition, each of these units is represented by the technical characteristics above described with values that range (-10%, +10%) of their average value - in particular for heat rate, variable O&M cost, no load cost, and startup cost.

For example, if from the expansion problem we got that the electric system needs 3,518 [MW] installed capacity of Steam Coal (with SO2 scrubber) technology, then the number of plants in the short-term model will be 5 units with maximum output of 600 [MW] each, and 1 unit with a maximum output of 518 [MW]. Then, each of these 6 units will have values for their heat rate, variable O&M cost, no load cost, and startup cost that will vary around the typical average value for a Coal technology (see Table 5.1-2).

g	$\overline{p}_g$ [MW]	hr_g [MMBtu/MWh]	vom_g [$/MWh]	nl_g [$/h]	su_g [$]	$change$ [%]
n5_1	600	9.200	4.52	161	21,447	0.00%
n5_2	600	9.507	4.67	166	22,162	3.33%
n5_3	600	8.893	4.37	156	20,732	-3.33%
n5_4	600	9.813	4.82	172	22,877	6.67%
n5_5	600	8.587	4.22	150	20,017	-6.67%
n5_6	518	10.120	4.97	177	23,592	10.00%

Table 5.1-2: Example of characteristics adopted for CCGT units in the short-term model

c. Other system parameters:

There are some other parameters we need to include such as the cost associated to non-served energy and spinning reserve. As mentioned in (82), to prevent unfeasible solutions the concept of non-served energy is introduced, which it is penalized in the

n5: Conventional pulverized coal steam plant - with SO2 scrubber (CoalOldScr)
n6: Conventional pulverized coal steam plant - with SO2 scrubber and biomass cofiring (CofireOld)
n7: Advanced supercritical coal steam plant - with SO2 and NOx controls (CoalNew)
n8: Advanced supercritical coal steam plant - with biomass cofiring (CofireNew)
n9: Integrated gasification combined cycle (IGCC) coal (CoalIGCC)
n10: IGCC with carbon capture and sequestration (CoalCCS)
n11: Oil/gas steam turbine (OGS)
n12: Nuclear plant (Nuclear)

[91] Loosely based on EIA's technology characteristics (81), we adopt the following unit size for each technology:

g	Unit size [MW]	g	Unit size [MW]	g	Unit size [MW]
GasCT	200	CoalOldScr	600	CoalIGCC	550
GasCC	300	CofireOld	600	CoalCCS	400
GasCCS	400	CoalNew	600	OGS	50
CoalOldUns	600	CofireNew	600	Nuclear	1,000

objective function with a very high cost value (Value of Lost Load, VOLL). In addition, a margin between the maximum capacity and output of the units connected to the system is left to enhance the reliability of the system. In the short-term model the hourly thermal spinning reserve is assumed to be the capacity of the largest unit in the system – i.e. 1,000MW of a nuclear plant - plus 1% of electric demand:

Non-served energy cost[92] [$/MWh]: $voll$

Spinning reserve [%]: rm

d. CO2 price and emissions:

Emissions depend on the technology and fuel type used by that particular technology. They can be included in the model either through an emission constraint or an additional cost in the objective function. In the latter case, we need a price (exogenously fixed every year) for the CO2 being emitted during the electric generation and heat production process:

CO2 emission rate[93] [ton/MMBtu]: ef_g

CO2 price[94] [$/ton]: p_y^{CO2}

Operation variables for every day

We develop a simple model to represent the hourly operation of an electric power system for each day of a particular year. In the model, we find continuous and binary variables for every hour of the day being analyzed:

Electric generation of thermal unit g for day d and hour h [MW]: $Q_{d,h,g}$

---

[92] For this work we assume a value equal to 8[$/kWh].

[93] According to ReEDS's "Table 16: Performance Parameters for Conventional Generation"(109), CO2 emission rates per technology are:

Technology	CO2 emission rate [lbs/MMBtu]	ef_g [ton/MMBtu]
GasCT	121.83	0.05526
GasCC	121.83	0.05526
GasCCS	12.18	0.00552
CoalOldUns	204.12	0.09259
CoalOldScr	204.12	0.09259
CofireOld	204.12	0.09259
CoalNew	204.12	0.09259
CofireNew	204.12	0.09259
CoalIGCC	204.12	0.09259
CoalCCS	20.41	0.00926
OGS	121.83	0.05526
Nuclear	0.00	0.00

[94] We assume a CO2 price equal to 98.74 [2007$/ton CO2-e] by year 20.

Non-served energy for day d and hour h [MW]: $Q_{d,h,nse}$

Startup decision of thermal unit g for day d and hour h [0/1]: $ON_{d,h,g}$

Shutdown decision of thermal unit g for day d and hour h [0/1]: $OFF_{d,h,g}$

Commitment decision of thermal unit g for day d and hour h [0/1]: $UC_{d,h,g}$

Constraints

In the model we include constraints related to energy balance, short-term reserve requirements, technical restrictions and environmental considerations.

a. Electric generation and load balance for every day:

Electric balance between generation and demand must be satisfied every hour of the day, including potentially non-served energy that the system may incur at some hours:

$$\sum_g Q_{d,h,g} + Q_{d,h,nse} \geq d'_{d,h} \quad \forall d,h$$

As explained above, demand is a *modified residual demand* that takes into consideration the contribution of micro-CHPs to supply electric demand to a particular number of householders:

$$d'_{d,h} = d_{d,h} \cdot \left(1+gr_y\right)^y - q_{d,h,chp}$$

b. Operating power reserve for every day:

The margin between the maximum capacity and electric production of the thermal generators connected each hour of the day has to supply some predetermined level of spinning reserve in the system. We need to mention that although in the long-term expansion model we are ensuring a margin of installed capacity enough to cover the system annual peak demand; in the short term model we are enhancing the system reliability with this additional margin (making the economic dispatch more expensive). Thus for example, in the case where there is an unforeseen increase in demand, the system will be able to quickly react to this event.

$$\sum_g \left(\overline{p}_g \cdot af_g \cdot UC_{d,h,g} - Q_{d,h,g}\right) + \left(\overline{p}_{chp} \cdot af_{chp} - q_{d,h,chp}\right) \geq 1{,}000MW + rm \cdot d_{d,h} \cdot \left(1+gr_y\right)^y \quad \forall d,h$$

Here we need to clarify that we are assuming that micro-CHPs contribute to the system reliability in the form of spinning reserve[95]. The reserve margin provided by

[95] Under this assumption, micro-CHPs should be able to respond to the system operator reserve requirements. Therefore, a key role in providing this type of service is the information and communication

micro-CHPs is assumed to be their maximum capacity $\overline{p}_{chp}$ minus their electric generation $q_{d,h,chp}$. Micro-CHP maximum capacity is given as part of the technology mix output from the long term expansion model, while $q_{d,h,chp}$ is the output from the HH model.

c. Maximum output power for every day:

Power plants have maximum production limits given by their hourly commitment and maximum generation output reduced by their availability rate:

$$Q_{d,h,g} \leq \overline{p}_g \cdot af_g \cdot UC_{d,h,g} \quad \forall d,h,g$$

d. Minimum output power for every day:

Similar to above, power plants have minimum production limits given by their hourly commitment and minimum generation output reduced by their availability rate. In this simple model we set the minimum output power as a percentage of the maximum generation output per plant[96].

$$Q_{d,h,g} \geq \underline{p}_g \cdot af_g \cdot UC_{d,h,g} \quad \forall d,h,g$$

e. Commitment and startup for every day:

Commitment decisions refer to the connection of the units during a particular hour, given startup and shutdown decisions of the previous hour. Thus, a unit that is connected cannot be started up, but it may be shut off. On the contrary, a unit that is not connected cannot be shut down, but it may be started up (82).

Therefore, the relationship between commitment, startup and shutdown decisions is given by:

$$UC_{d,h,g} = UC_{d,h-1,g} + ON_{d,h,g} - OFF_{d,h,g} \quad \forall d,h,g,$$

Where $ON_{d,h,g} = 1$ means that the plant starts up, and $OFF_{d,h,g} = 1$ means that the plant shuts down at the beginning of hour h. In addition, we define an initial state $UC_{d,h=0,g}$ for every generating plant. For simplicity we assume that nuclear and some coal power plants are always committed at the beginning of the day, i.e. $UC_{d,h=0,g=n4\,\&\,n5} = 1$ and $UC_{d,h=0,g=n12} = 1$. For the other technologies, we assume they are not initially committed.

infrastructure in place, as well as the control capabilities over a large number of dispersed micro-CHP units.

[96] In particular, we assume 100% for nuclear, 33% for coal, 20% for CCGT, and 0% for peaking units.

f. Additional startup constraints for every day:

We add additional constraints to the startup of coal and nuclear power plants. As they are mostly considered base load plants, we require those plants to start up at most once per day - i.e. we did not allow the model to turn them on and off several times per day[97]:

$$\sum_h ON_{d,h,g=coal} \leq 1 \qquad \forall d, g = coal$$

$$\sum_h ON_{d,h,g=nuclear} \leq 1 \qquad \forall d, g = nuclear$$

g. CO2 emissions:

We need to note that we do not explicitly include a limitation to the amount of CO2 emissions by conventional power plants and micro-CHPs. From the long-term expansion model we obtain a technology mix that already has annual CO2 emissions limitations, that considers not only the emission from micro-CHPs and heating devices but also from the electric power plants.

Objective function

The goal of the problem is to minimize the operational costs of producing electricity, including the costs of starting up and connecting the units to the system, CO2 emissions per technology and the cost of non-served energy. The objective function (OF) is defined for every day of a particular year under analysis:

a. Thermal unit variable costs for every day:

$$\sum_h \sum_g \left[Q_{d,h,g} \cdot \left(f_g \cdot hr_g \cdot (1 + esc_y)^y + vom_g + p_y^{CO2} \cdot ef_g \cdot hr_g \right) \cdot (1 + lf) + su_g \cdot ON_{d,h,g} + nl_g \cdot UC_{d,h,g} \right]$$

[97] All coal technologies are taken into account in this restriction.

Where,

esc_y is an annual escalation factor used for fuel prices to reflect price increase over the time horizon,

lf is an energy loss factor that reflects network losses incurred by centralized power plants to supply demand at lower voltage levels[98].

In this model we adopt a single node representation (i.e. no network representation), where the electric demand is supplied at a medium/low voltage node, close to end-users, instead of a high voltage node.

b. Non-served energy cost for every day:

Within the OF we add an expression for the additional costs the system may incur if some demand is not served by electric generators:

$$\sum_h \left[Q_{d,h,nse} \cdot voll \right] \quad \forall d$$

Complete formulation

Finally, the daily UC model is formulated as follows for every day of the last year of the time horizon being studied:

[98] As generators need to produce more energy to supply a particular demand, we assume a $lf = 10\%$ to reflect an increase of their variable costs with respect to the cost incurred by local generation like micro-CHPs.

$$Minimize \sum_{h}\sum_{g}\left[Q_{d,h,g}\cdot\left(f_{g}\cdot hr_{g}\cdot\left(1+esc_{y}\right)^{y}+vom_{g}+p_{y}^{CO2}\cdot ef_{g}\cdot hr_{g}\right)\cdot\left(1+lf\right)+su_{g}\cdot ON_{d,h,g}+nl_{g}\cdot UC_{d,h,g}\right]+\sum_{h}\left[Q_{d,h,nse}\cdot voll\right]$$

$$s.t.\begin{cases}\sum_{g} Q_{d,h,g}+Q_{d,h,nse}\geq d'_{d,h} & ;\forall d,h\\ \sum_{g}\left(\overline{p}_{g}\cdot af_{g}\cdot UC_{d,h,g}-Q_{d,h,g}\right)+\left(\overline{p}_{chp}\cdot af_{chp}-q_{d,h,chp}\right)\geq\left(1{,}000MW+rm\cdot d_{d,h}\cdot\left(1+gr_{y}\right)^{y}\right) & ;\forall d,h\\ Q_{d,h,g}\leq\overline{p}_{g}\cdot af_{g}\cdot UC_{d,h,g} & ;\forall d,h,g\\ Q_{d,h,g}\geq\underline{p}_{g}\cdot af_{g}\cdot UC_{d,h,g} & ;\forall d,h,g\\ UC_{d,h,g}=UC_{d,h-1,g}+ON_{d,h,g}-OFF_{d,h,g} & ;\forall d,h,g\\ \sum_{h} ON_{d,h,g=coal}\leq 1 & ;\forall d,g=coal\\ \sum_{h} ON_{d,h,g=nuclear}\leq 1 & ;\forall d,g=nuclear\\ Q_{d,h,g}\geq 0 & ;\forall d,h,g\\ Q_{d,h,nse}\geq 0 & ;\forall d,h\\ ON_{d,h,g}\in\left[0,1\right] & ;\forall d,h,g\\ OFF_{d,h,g}\in\left[0,1\right] & ;\forall d,h,g\\ UC_{d,h,g}\in\left[0,1\right] & ;\forall d,h,g\end{cases}$$

Where,

$$d'_{d,h}=d_{d,h}\cdot\left(1+gr_{y}\right)^{y}-q_{d,h,chp}$$

5.1.2.2. Iterative process

While explaining the formulation for the daily unit commitment (UC) model, we mentioned that the electric production coming from micro-CHPs ($q_{d,h,chp}$) is considered as an exogenous input for this particular UC model. However, this value is obtained through the HH model explained in Chapters 3 and 4. We need to recall that the HH model is based on a decentralized intelligent control operation of micro-CHPs at the residential level, where energy (electricity & heat) costs are minimized. Under this formulation, micro-CHPs are able to react to energy prices to decide their most efficient operation taking into consideration not only customers' electric demand but also their heat requirements.

As shown in Figure 5.1.3, the iterative process is done with the purpose of obtaining the total micro-CHP aggregated electric production $\left(Q_{chp}\right)$ in a system with a large number of users operating these machines. From the UC model we determine the system's short-term marginal prices, which are passed to final customers who decide the least-cost operation of their micro-CHPs. The system load duration curve $\left(Load\right)$ is modified to take into account the total contribution from these micro-CHPs $\left(Q_{chp}\right)$.

As a result, the conventional power plants in the system produce Q_g of electricity to meet the *system residual demand* $(Load')$.

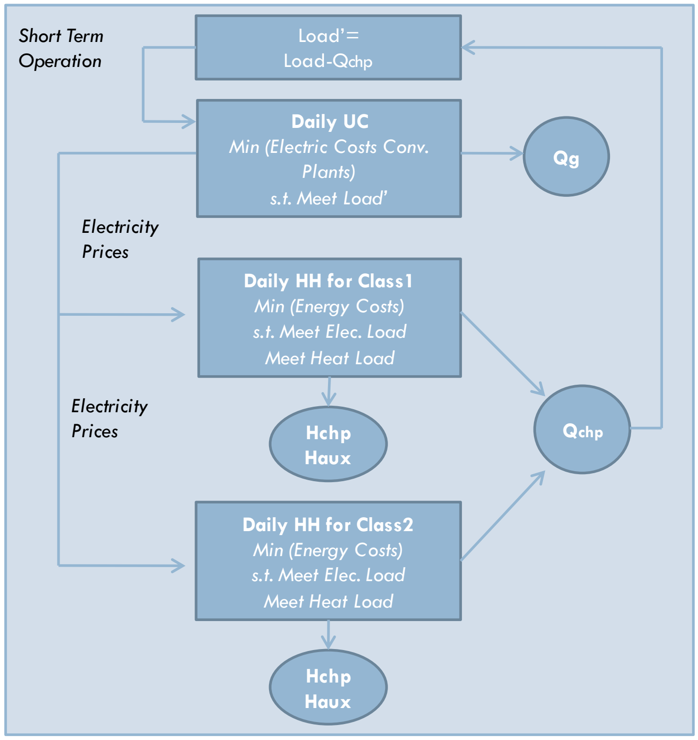


Figure 5.1.3: General short-term iterative process

In more detail, the iterative process follows the next sequence (see Figure 5.1.4):

a. From the long-term capacity expansion problem we get the technology portfolio of an optimally adapted electric system to demand requirements. As we focus the short-term analysis on only one year, we take the results from last year of the time horizon of the expansion model[99].

b. For the first iteration we assume an initial value for micro-CHP electric production (Q^0_{chp}) and calculate the *residual demand* $(Load')$to be supplied by electric power plants.

c. A daily unit commitment (UC) is performed to get hourly scheduling and commitment decisions of generation plants, as well as hourly marginal prices in the system $(SRMP)$.

d. The system electricity prices $(SRMP)$ are fed back as input into the HH model.

e. The household (HH) model is run for the day for every class of customer with distinct electric and heat profiles. Householders owning micro-CHPs decide the

[99] By the end of the time horizon, i.e. 20 years in total, the electric system has had the time to adapt to demand, fuel price and environmental restrictions.

most efficient operation of their units according to the energy price signals they receive from the system (electricity and gas prices).

f. Micro-CHP electric production coming from the different classes of customers is aggregated for every hour of the day (Q_{chp}).

g. System electric demand $(Load)$ is modified by subtracting the total electric production from micro-CHPs. This *residual demand* $(Load')$, as mentioned in *step b*, has to be supplied by the conventional electric power plants.

h. The iterative process ends when the operational response of micro-CHPs does not change, i.e. if the $SRMP$ of two consecutive iterations is the same. A new iteration is done whenever the convergence criterion has not been reached.

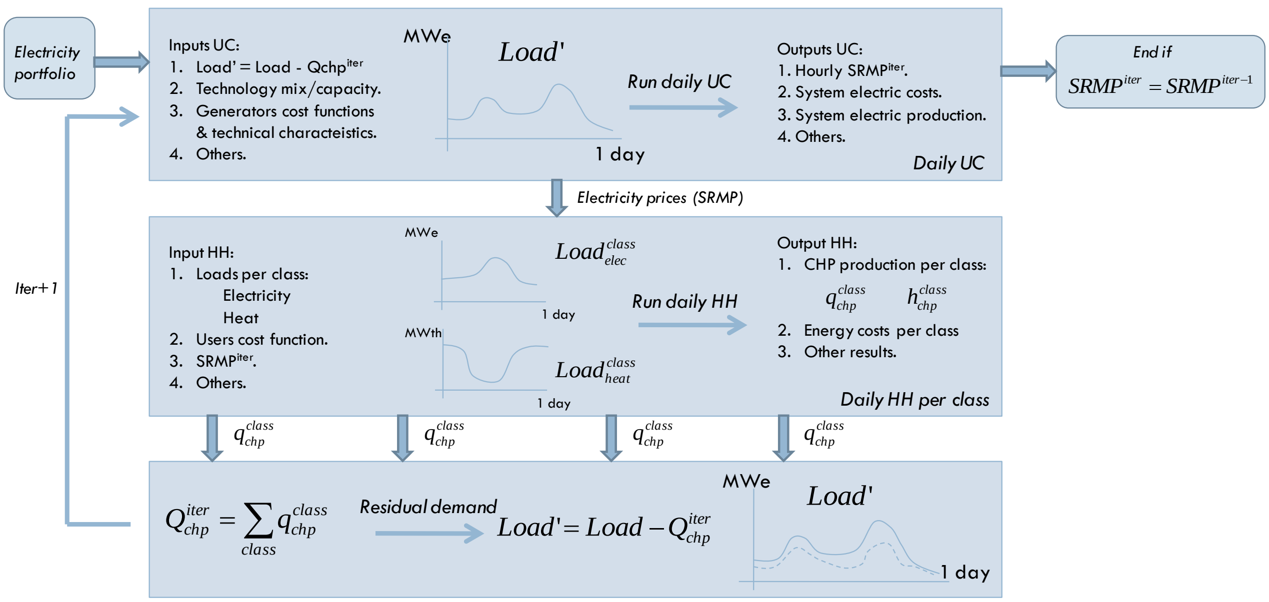


Figure 5.1.4: Short-term iterative process

Final electricity price given to end-users

We can see from the description of the iterative process that energy prices are a central element from the model. Final customers need to receive the right economic signals to make an efficient use of the service (for example, efficient use of resources while internalizing environmental impact). In addition, energy prices are used to collect money required to cover all the costs of supplying electric power in the generation, transmission and distribution activities. Therefore, it is necessary to implement a tariff structure that includes not only the short-term electricity prices but also other components that include generators fixed operation costs, system's reserve adequacy, and transmission and distribution network costs.

The methodology for defining an electricity tariff to each type of customer is complex and varies much among different utilities. In (83) a detailed description of the process can be found. Here we present a stylized description of the methodology that will be useful for the purpose of defining and computing a reasonable electric tariff to be applied to final consumers in the case study that is examined in this chapter.

The electric tariff is characterized by three main components: energy [$/kWh], capacity [$/kW] and customer [$]. Costs related to producing electricity – capital costs, fixed and variable O&M, fuel related costs – are normally recovered through the energy charge[100]. In addition, distribution and transmission network costs – investment and O&M[101] – are recovered through the energy and/or capacity charges. Finally, there are additional charges such as regulatory and retailing charges used to fund energy conservation and renewable energy programs, in addition to connection, metering and administrative costs for final customers (see Table 5.1-3).

Activities	Units
Generation costs	
Energy	[$/MWh]
Capacity	[$/MW]
Transmission costs	
Energy	[$/MWh]
Capacity	[$/MW]
Distribution costs	
Energy	[$/MWh]
Capacity	[$/MW]
Regulatory costs	
Transition, Conservation, Renewable	[$/MWh]
Retailing costs	
Customer charge	[$/customer]

Table 5.1-3: Electric cost drivers

Electricity costs are allocated according to the voltage levels in the system, aggregated into brackets according to some criterion. In the absence of real-time pricing, groups of customers are defined according to their consumption profile and given a distinct tariff. In addition, load curves for each tariff level are estimated to define time-of-use periods. Lastly, costs are allocated according to each of the cost drivers above mentioned, voltage level, customer type, and time-of-use block.

[100] In addition, the electricity operator/regulator may require a long-term guarantee of supply which is usually recovered through a capacity charge.
[101] Costs incurred by network operators are intended to reduce network losses and to cover peak demand.

At the end of the process, the resulting electric tariff is distinctive for each customer group, with a matrix-like structure where each cell defines every tariff level (see Table 5.1-4):

Type customer	Winter		Summer	
	Peak	Off-peak	Peak	Off-peak
LV	Energy $/kWh Capacity $/kW Customer $/cust.	Energy $/kWh Capacity $/kW Customer $/cust.	Energy $/kWh Capacity $/kW Customer $/cust.	Energy $/kWh Capacity $/kW Customer $/cust.
MV	Energy $/kWh Capacity $/kW Customer $/cust.	Energy $/kWh Capacity $/kW Customer $/cust.	Energy $/kWh Capacity $/kW Customer $/cust.	Energy $/kWh Capacity $/kW Customer $/cust.
HV	Energy $/kWh Capacity $/kW Customer $/cust.	Energy $/kWh Capacity $/kW Customer $/cust.	Energy $/kWh Capacity $/kW Customer $/cust.	Energy $/kWh Capacity $/kW Customer $/cust.

Table 5.1-4: Simplified electric tariff structure

For the purpose of our research and given the limited available information, we have made several simplifications to construct a simple tariff to pass to final customers:

- The charges of interest for the case study are only the final tariffs for end consumers at low voltage level. In addition, it is needed to estimate the difference in network charges between conventional generators that are connected at transmission level and micro-CHP generators connected at the low voltage distribution grid.
- *Generator costs* are paid in full (100%) by end-users with the costs allocated in the form of energy and demand charges. These include hourly electricity prices, uplift charges, and reserve adequacy payments.
- *Transmission costs* are paid in full (100%) by end-users in the form of energy and demand charges for peak and non-peak hours[102].
- *Distribution costs* are paid in full (100%) by end-users in the form of energy and demand charges for peak and non-peak hours.
- *Energy charges* are spread over peak and non-peak hours in proportion to the energy and average power of each energy block. *Demand charges* – typically $ per kW of contracted capacity – are not used here, since in the US the tariffs for low voltage end consumers are usually applied as a single charge in $/kWh of consumed energy plus an annual fixed commercial charge. Therefore, these charges in our analysis are estimated for peak hours, and allocated in proportion to the power of the peak energy block spread over the hours of the block[103].

[102] In some power systems generators also pay a fraction of the transmission network costs, but here we follow the usual practice in the U.S.
[103] Peak energy block has 964 hours in our analysis.

In Table 5.1-5, we illustrate how costs paid by end-users are being allocated to energy and demand charges, for peak and non-peak hours:

Charges paid by end-users	Energy charge		Demand charge
	Peak [$/kWh peak]	Non-peak [$/kWh non-peak]	Peak [$/kWh peak]
100% Generation Costs	*SRMP* *Uplift*	*SRMP* *N/A*	*Capacity adequacy*
100% Transmission Costs	*%Transmission cost*	*%Transmission cost*	*%Transmission cost*
100% Distribution Costs	*%Distribution cost*	*%Distribution cost*	*%Distribution cost*

Table 5.1-5: Costs paid by end-users within an electricity retail rate

In the sections below, we explain in detail how these components are computed and included in the electricity retail tariff paid by end-users.

1. Generation costs:

Generation costs are recovered through hourly short-term electricity prices, and uplift charges during peak times. Additional adequacy payments may be required if the regulator needs to increase the reliability of the system, which is the case in the New England system, by means of the Forward Capacity Mechanism.

- *Hourly electricity prices* $SRMP_{d,h}$ [$/MWh] are obtained from the UC model. We need to note that in the short-term model the electricity supplied by power plants is withdrawn by final consumers at a low voltage node requiring generators to produce more electricity to cover the losses in the network. Since their production costs increase, we use an *energy loss factor* of 10% over the variable costs of conventional plants to reflect this increment.

- *Generation capacity payments* $GC_{h\in peak}^{LT\,adequacy}$[$/MWhpeak] are estimated using data from the results of the ISO-NE's forward capacity auction[104] for three consecutive periods from 2010 up to 2012 (84) (85) (86). We took the capacity clearing price and the net installed capacity requirements, and then we estimated the total weighted capacity payments in the system $GC^{LT\,adequacy}$[105]. Although these costs are normally allocated in the form of demand charge for a specific amount of

[104] See ISO-NE's Forward Capacity Auction results for 2010-2011, 2011-2012 and 2012-2013 periods at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/.

[105] Based on the values shown in the table below, the total generation capacity payment ($GC^{LT\,adequacy}$) was estimated to be about 1,380 [MM$2007] for the year under study:

	Net Installed Capacity Requirement [MW]	Capacity Clearing Price [$/kW-mo]	Total FCM Payments [MM$/yr]
June 2010-May 2011	32,305	4.500	1,744
June 2011-May 2012	32,528	3.600	1,405
June 2012-May 2013	31,965	2.951	1,132

contracted capacity, for simplicity in our analysis we estimate an energy component charged on peak hours – i.e. the capacity payments spread over the peak energy block.

- *Uplift charges* $Uplift_{d,h\in peak}$ [$/MWhpeak]. As mentioned in (87), for the more simple economic dispatch formulation the energy prices obtained as solution of the problem support the supply-demand market equilibrium[106]. These prices are charged to loads and paid to generators. However, the UC formulation is discrete (fixed costs) and some of its decision variables are binary (commitment decision variables). The market clearing prices derived from the system marginal costs provide the necessary payments to cover the variable costs of producing electricity. However they do not provide all the payments to recover fixed costs associated to the commitment of power plants for scheduling purposes (i.e. neither start-up costs nor no-load costs). Therefore additional payments - known as *uplift charges* - are required from final customers to cover these additional costs on top of energy payments.

  We need to clarify that the core of our research is not focused on this particular subject, so to overcome this problem we implemented an ad hoc approach that guarantees cost recovery to all generators and which is close to the actual arrangements that are presently used in some US power systems. A deeper discussion on the topic can be found at (87), (88), (89).

  Under the UC formulation, we pay uniform hourly energy prices to all generators, but as mentioned their infra-marginal energy revenues may not be enough to cover total fixed costs and variable costs incurred during a particular day. Therefore, generators receive an *additional income* that is added to their energy revenues. Conversely, loads pay an *uplift charge* that is added to the short-run marginal price $SRMP$.

- *Extra income received by generators*. From the UC model we know those generators being committed for every hour of the day. We pay them a lump sum at the end of the day that covers their total fixed operation costs, i.e. start-up and no-load costs:

$$Income_{d,g}^{extra} = \sum_h \left(su_g \cdot ON_{d,h,g} + nl_g \cdot UC_{d,h,g} \right) [\frac{\$}{\text{day}}]; \qquad \forall d, g$$

[106] System marginal prices are the dual variable associated to the supply-demand balance equality equation.

Thus, the generators' total income per day is given by the sum of their energy revenues and this extra income:

$$Income_{d,g}^{total} = Income_{d,g}^{extra} + \sum_{h} \left(SRMP_{d,h}^{iter*} \cdot Q_{d,h,g} \right) [\frac{\$}{\text{day}}]; \quad \forall d, g$$

We note that the energy infra-marginal income is given by the generator's electric production times the short-run marginal price obtained in the last iteration $\left(SRMP_{d,h}^{iter*} \right)$ of the iterative process, where the model has reached the convergence criterion.

- *Uplift charge paid by load.* As generators are entitled to receive the extra income, the load should make additional payments to the system. We calculate the hourly uplift charge as an additional energy component to the $SRMP_{d,h}$, given by the sum of the generators' extra income divided by the electrical load during the peak hours of the day:

$$Uplift_{d,h \in peak\_hours} = \frac{\sum_{g} Income_{d,g}^{extra}}{\sum_{h \in peak\_hours} d'_{d,h}} [\$/\text{MWh}/\text{day}]; \quad \forall d$$

Hence, the load gets a total energy price given by:

$$SRMP_{d,h}^{UP} = SRMP_{d,h} + Uplift_{d,h \in peak\_hours} [\$/MWh/day]; \quad \forall d$$

Where, the uplift charge is added to the electricity price only during the peak hours of the day.

Finally, the total load's payment per day is given by the residual electrical load $d'_{d,h}$ times the short-run marginal price taking into account the uplift charge:

$$Payment_{d}^{total} = \sum_{h} \left[\left(SRMP_{d,h}^{iter*} + Uplift_{d,h \in peak\_hours} \right) \cdot d'_{d,h} \right] [\frac{\$}{\text{day}}]; \quad \forall d$$

Where,

$$d'_{d,h} = d_{d,h} \cdot \left(1 + gr_y \right)^y - Q_{d,h,chp}$$

2. Transmission & distribution network costs:

Transmission and distribution network costs should result in energy and capacity charges. However, in many power systems and in the US in particular, just energy charges are used. Therefore, here we use just energy charges for every energy block, and capacity charges will be allocated according to the energy of the peak energy block – instead of using the contracted demand.

- *Transmission and distribution energy charge* [$/MWhpeak, $/MWhnon-peak] is estimated using 50% of the system's network costs. Of these, certain proportion goes to peak energy charge and the other to non-peak energy charge.

- *Transmission and distribution demand charge* [$/MWhpeak] is estimated using 50% of the system's network distribution costs. These costs are allocated as demand charge.

In the energy charge case, the allocation is proportional to the average power times the energy of the block spread over the energy of the block. In particular for our calculations, the load duration curve[107] was simplified using two energy blocks that concentrated peak and non-peak hours of the year (see Figure 5.1.5). Then, for peak hours, $\%^{peak}$ is calculated using the following expression:

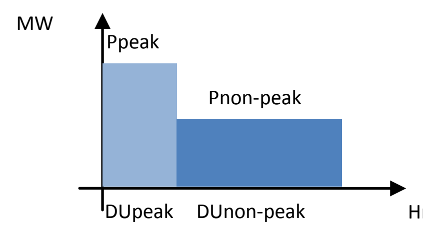


Figure 5.1.5: Two blocks electric load curve

$$\%^{peak} = \frac{\left(Energy^{peak} \cdot Power^{peak}\right)}{\left(Energy^{peak} \cdot Power^{peak}\right) + \left(Energy^{non-peak} \cdot Power^{non-peak}\right)}$$

Where,

$Power^{peak} = 20{,}502MW$, $Energy^{peak} = 19{,}764GWh$ and $DU^{peak} = 964h$,

$Power^{non-peak} = 14{,}713MW$, $Energy^{non-peak} = 114{,}703GWh$ and $DU^{non-peak} = 7{,}796h$.

Using these numbers, the proportion of network costs allocated to energy charges is: $\%^{peak} = 19\%$ and $\%^{non-peak} = 81\%$.

[107] Electric demand based on ISO-NE demand for year 2007. Refer to footnote #78.

Data regarding network costs (*TC & DC*) in the system are not fully available in general. We made some simplifications and assumptions to get numbers that are representative of the costs of an electrical system. From NSTAR's Reconciliation Filings to the Massachusetts Department of Public Utilities[108](90), we gathered data for the 2008 proposed revenues for all rate classes - broken down into seven rate components - and the total annual energy delivered by Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company (see Table 5.1-6).

Since we are working with an electric system similar to ISO-NE, we scaled up the total revenues per component by the total system's electrical load[109]. The results per component are shown in Table 5.1-6, where for the above explained calculations we only take the distribution (DC) and transmission costs (TC):

Cost component	**Total NSTAR** [$2007]	**Estimated system's cost** [$2007]	**% total**
Customer	89,881,366.0	567,913,826	3%
Distribution (DC)	*743,299,821.0*	*4,696,526,814*	*21%*
Transition	307,151,373.0	1,940,730,535	9%
Transmission (TC)	*148,757,026.0*	*939,918,646*	*4%*
Energy Conservation	53,213,367.0	336,227,721	2%
Renewable Energy	10,642,673.0	67,245,542	0%
Generation	2,187,541,130	13,821,940,062	62%
Total Costs	**3,540,486,756**	**22,370,503,146**	100%
Annual Energy	**21,285,347,041**	**134,491,090,000**	kWh

Table 5.1-6: Electricity costs per rate component for a New England-like electrical system

[108] See "Petition of NSTAR Electric Company to the Department of Public Utilities for review and approval of its 2007 Distribution Rate Adjustment/Reconciliation Filing", ELECTRIC 07-81 Initial Filing, Exhibits HCL-3 for BEC, CAM and COM at http://www.env.state.ma.us/dpu/docs/electric/07-81/10107nstdrarf.pdf.
[109] We use a factor of 6.3 to increase costs. For year 2007, the estimated energy sold by NSTAR was about 21,285 GWh, while the total system's electric demand was about 134,491GWh.

3. Final electricity price:

Considering what has been explained, the allocation methodology of the charges paid by end-users is summarized in Table 5.1-7 below.

Charges paid by end-users	**Energy charge**		**Demand charge**
	Peak [$/kWh peak]	**Non-peak** [$/kWh non-peak]	**Peak** [$/kWh peak]
100% Generation Costs	$SRMP_{d,h}$ with lf $Uplift_{d,h\in peak}$	$SRMP_{d,h}$ with lf $Uplift_{d,h\in non-peak}=0$	$GC_{h\in peak}^{LT\ adequacy}=\frac{(100\%\cdot GC^{LT\ adequacy})}{Energy^{peak}}$
100% Transmission Costs	$\frac{(50\%\,TC)\cdot\%^{peak}}{Energy^{peak}}$	$\frac{(50\%\,TC)\cdot(1-\%^{peak})}{Energy^{non-peak}}$	$\frac{(50\%\,TC)}{Energy^{peak}}$
100% Distribution Costs	$\frac{(50\%\,DC)\cdot\%^{peak}}{Energy^{peak}}$	$\frac{(50\%\,DC)\cdot(1-\%^{peak})}{Energy^{non-peak}}$	$\frac{(50\%\,DC)}{Energy^{peak}}$

Table 5.1-7: Energy and demand charges paid by end-users

Where the cost data used in the calculations for a system with similar characteristics to New England is the following[110]:

Generation costs ($GC^{LT\ adequacy}$)	[MM$2007/yr]	1,380
Transmission costs (*TC*)	[MM$2007/yr]	940
Distribution costs (*DC*)	[MM$2007/yr]	4,697

Table 5.1-8: Estimated system's electricity costs used in ST model

Therefore, based on the methodology, simplifications and data above explained, we calculated the energy charges to be paid by end-users due to generation, transmission and distribution costs (see Table 5.1-9 for results).

Charges paid by end-users	**Energy charge**		**Demand charge**
	Peak [$/kWh peak]	**Non-peak** [$/kWh non-peak]	**Peak** [$/kWh peak]
Generation Costs:			
ST electricity price	$SRMP_{d,h}$	$SRMP_{d,h}$	0.0000
Uplift charge	$Uplift_{d,h}$	0.0000	0.0000
Generation capacity charge	0.0000	0.0000	0.0698
Transmission Costs	0.0046	0.0033	0.0238
Distribution Costs	0.0230	0.0165	0.1188

Table 5.1-9: Estimated energy & demand charges included in the final electricity price given to end-customers

[110] Refer to previous section for an explanation of the sources being used.

Finally, as we mentioned, final customers need to receive the economic signals that encourage an efficient use of resources, while recovering the total costs of providing electricity. Therefore, the price that residential customers end up receiving is given by adding all the terms showed in Table 5.1-9:

- Short-term electricity prices obtained from the daily UC model: $SRMP_{d,h}$.
- Uplift charge applied during peak hours: $Uplift_{d,h\in peak\_hours}$.
- Generation capacity charge during peak hours: $GC_{h\in peak}^{LT\ adequacy}$.
- Network energy & demand charges for peak & non-peak hours: $NCE_{h\in peak}$ & $NCE_{h\in non-peak}$.

Where $NCE_{h\in peak}$ is the sum of the transmission & distribution charges (energy and demand) for peak hours, while $NCE_{h\in non-peak}$ is the sum of the network charges (energy) for non-peak hours[111].

As a result, the final hourly electricity price per day [$/kWh/day] is given by:

$$\begin{aligned} SRMP_{d,h}^{UP+GC+NCE} = {} & SRMP_{d,h} \\ & + Uplift_{d,h\in peak} \\ & + GC_{h\in peak}^{LT\ adequacy} \\ & + NCE_{h\in peak} + NCE_{h\in non-peak}\ ;\forall d \end{aligned}$$

[111] In particular:
$NCE_{h\in peak}$ = 0.0046+ 0.0230+0.0238+0.1188 = 0.1702 [$/kWh peak], and
$NCE_{h\in non-peak}$ = 0.0033+ 0.0165 = 0.0198 [$/kWh non-peak].

Customers classes and customer aggregation

Because of the long running times of the HH module, the iterative process works with *classes of customers* which aggregate a large number of customers in each. Classes are characterized by different electric and heat load profiles, each simulated using the energy simulator Energy-10® (refer to Chapter 3 for more details). Energy profiles are obtained for two classes of customers, both located in a Boston weather-like area:

- *Customer class 1* is characterized by residential customers living in medium size houses of 2500sqft, with a thermostat set at 72/76ºF. Annual electric load per customer is about 11.8 [MWhe/yr], with a maximum load of 4.5kWe and an average of 1.3kWe. Annual heat load (domestic heat water and heating) is about 33.8 [MWhth/yr], with a maximum load of 20.1kWth and an average of 3.9kWth.

- *Customer class 2* is characterized by residential customers living in large size houses of 4500sqft, with a thermostat set at 72/76ºF. Annual electric load per customer is about 20.6 [MWhe/yr], with a maximum load of 7.0kWe and an average of 2.4kWe. Annual heat load is about 46.2 [MWhth/yr], with a maximum load of 27.7kWth and an average of 5.3kWth.

In addition, we assume that each class has one type of micro-CHP technology characterized by either a low heat-to-power ratio (HPR) or medium HPR, both with the same electrical capacity. A micro-CHP technology is assigned to a particular class of customer according to the results from the long-term expansion problem (see next section). From these results we know the amount of installed capacity required to meet the energy demand for the last year of the time horizon. Then, for the short-term analysis we estimate the number of end-users within each class of customer using a micro-CHP. For this purpose we determine the optimum micro-CHP size for the energy and economic conditions in year t20. Based on a simple payback period of 8.5 years for both classes of customers – considering incremental investment costs and operational savings – we determined a micro-CHP unit of size of 0.8[kWe] and 1.3[kWe] for customer C1 and C2 respectively. Then we calculate the number of residential customers having micro-CHPs according to the total installed electric capacity estimated in the expansion model. In particular, the electric installed capacity of micro-CHP HPR2.7 for customer class C1 in year t20 is 2,171MW, accordingly the number of customer is 2,713,113. For customer class C2, the number of users operating this technology would be 1,678,000 (see details in Appendix C.12. Micro-CHP optimum size analysis for customer class C1 & C2).

Once defined the customer classes, we run the HH module for each class and get the outputs we need to then run the daily UC module. Results such as micro-CHP electricity production and energy costs per class are then increased according to the number of customers considered in each class. This methodology is quite simple and it has drawbacks like lack of diversification in the number of technologies and the customers being considered, but it works in terms of speeding up run times of the HH module[112].

Once results per class are increased, we aggregate results of all the classes being considered and feed them back as (Q_{chp}) to be used by the UC model. Recall that the system electric demand is modified by subtracting the total electric production from micro-CHPs and the resulting *residual demand* $(Load')$ is the one that will be supplied by the conventional electric power plants represented in the UC model (recall iterative process from page 138). The methodology used for customer class aggregation is shown in Figure 5.1.6 below:

[112] The Total run time for the iterative process (HH and UC models) is given by the run times of each module per customer class: (i) HH module takes about 25-30 seconds for 1 customer class, (ii) UC module takes about 2 seconds for an electric power system with about 60 power plants for a 24 hour period. Thus, the total estimated run time for 1 customer class and for a given number of days is given by:

$$Run\ time = \sum_{day} \left[\left(\# Customer^{class} \right) \cdot Time^{HH} + Time^{UC} \right] \cdot \left(\# Iterations_{day} \right)$$

For example, the estimated running time for 2 classes of customers and 365 days - assuming the convergence is reached in 5 iteration each day – will roughly be:

$$Run\ time = \left[\left(2 class \cdot 30 \sec + 2 \sec \right) \cdot 5 iter \right] \cdot 365 day = 113{,}150 \sec \approx 32 hours$$

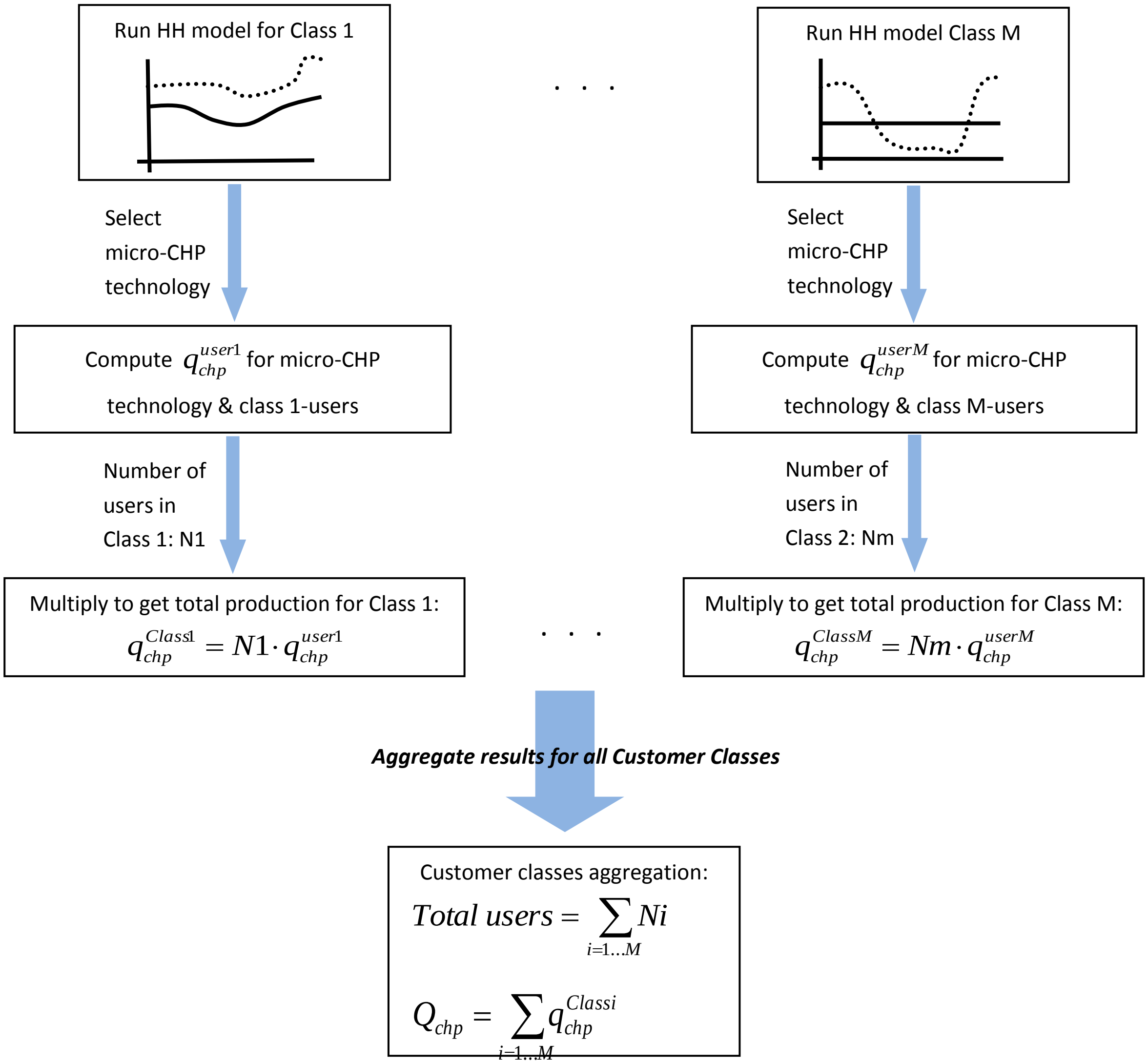


Figure 5.1.6: Methodology used for aggregating customers results

Details on convergence

The proposed methodology based on the HH and UC modules integration needs a convergence criterion to stop the iterative process. As mentioned, this criterion is based on the [24×1] electricity price vector, where for two consecutive iterations the prices should be the same. This means that, from one iteration to the next one, the operational response of micro-CHPs does not change. Since they see the same price signal, they do not have incentive in changing their operational decision.

Specifically, the convergence criterion is based on the $SRMP_{d,h}^{iter}$ - without uplift and energy network charges. An electricity price error is calculated and assessed to see if it is low enough to finish the iterative process:

$$\left[Error\_SRMP_{d}^{iter} = \sum_{h=1,24} \left(SRMP_{d,h}^{iter} - SRMP_{d,h}^{iter-1} \right)^{2} \right] \leq tol; \forall d$$

However, at some days the process does not converge because it enters into a loop. The system marginal price for a particular hour of the day oscillates between a high and a low value, where a high price makes micro-CHPs to operate while a low price does not give them incentive to operate. This can be explained as follows:

- At one particular hour, micro-CHPs operate according to a certain price signal and the market demand is reduced, i.e. the residual demand. The marginal electric generator in the power system changes to a cheaper one.

- In the next iteration, the marginal electricity price passed onto final consumers is low enough to modify the operation of micro-CHPs which now do not operate. As a consequence, the residual market demand increases (as there is no micro-CHP electricity production) and the marginal generator changes back to a more expensive one.

- For the next iteration, the price seen by micro-CHPs is high enough again to incentivize the operation of micro-CHPs.

The solution to this situation rests on comparing the economic social welfare – energy operational production cost - among iterations. From a centralized operation perspective, analyzing the impacts of micro-CHPs within an energy system calls for looking not only at the individual net benefits, but also the benefits of the overall system considering consumers with and without micro-CHPs, and generators. Within the loop we compare the global net social benefit of each iteration and, from an ideal perspective of a central regulator we look for the maximum benefit.

Specifically, we exit the oscillating loop in the iteration where the economic welfare is the largest within the loop:

$$Is\ \left[\ welfare_d(iter) = Max\left(welfare_d(1:iter-1)\right)\ \right]?\quad ;\forall d$$

Daily economic welfare (or operational production cost) is defined as the sum of producer's surplus and consumer's surplus. Here we assume that individual consumer's demand does not change with electricity prices[113]:

- Conventional generators surplus per day d [114]:

  $\left(Income - Operational\ Costs\right)_d ;\forall d$

- Consumers (without micro-CHP) surplus per day d [115]:

  $Utility(assumed\ constant) - \left(Electric\ Costs + NSE\ Cost\right)_d ;\ \forall d$

- Consumers (with micro-CHP) surplus per day d [116]:

  $Utility(assumed\ constant) - \left(Electric\ Costs + Operational\ Costs\right)_d ;\ \forall d$

The mathematical expression for the economic welfare per day d is given by:

$$\begin{aligned}
&Welfare_d = \\
&+\sum_g \sum_h \left(SRMP_{d,h}^{iter} - VC_{d,h,g}\right)\cdot Q_{d,h,g} \\
&-\left(\sum_h \left(d_{d,h}\cdot\left(1+gr_y\right)^y - Q_{d,h,chp}\right)\cdot SRMP_{d,h}^{UP,iter} + \sum_h Q_{d,h,nse}\cdot voll\right) \\
&-\left(\sum_h \sum_{class}\left(q_{d,h,chp}^{class}\cdot VC_{d,h,chp}^{class} + h_{d,h,aux}^{class}\cdot VC_{d,h,aux}^{class}\right)\right);\forall d
\end{aligned}$$

---

[113] Since in this thesis we want to understand the operation of micro-CHPs and their future implications, we leave out of the analysis the fact that consumer's demand could be price elastic. On one hand, in the short-term analysis we assign each individual customer a demand for heat and electricity that does not change with energy prices – i.e. no reduction or load shifting is represented in the model. On the other hand, we assumed that self-generation coming from micro-CHPs is able to respond to energy price signals. In other words, end-users owning micro-CHPs can decide the operation of their machines to produce the energy they need at times that are the most favorable for them (for example when electricity retail prices are very expensive).

[114] We need to clarify that costs incurred by generators because of start-up and no-load costs are recovered through the extra income paid as a lump sum at the end of the day. Thus, in the expression for generators surplus we do not include neither of these terms, and their electricity production is paid at $SRMP_{d,h}$ with no uplift charges included in it.

[115] Electricity costs refer to the costs for end-users of purchasing electricity from the grid. Here the electricity price with uplift charges is used for valuing the purchases of electricity $SRMP_{d,h}^{UP}$.

[116] Operational costs refer to the costs for micro-CHP owners of operating the machine, which include fuel costs, variable O&M and potentially CO2 emissions costs.

Where, VC is the total variable cost of operating conventional power plants, micro-CHPs and conventional heating systems respectively:

$$VC_{d,h,g} = \left(f_g \cdot hr_g \cdot (1+esc_y)^y + vom_g + p_y^{CO2} \cdot ef_g \cdot hr_g\right) \cdot (1+lf)$$

$$VC_{d,h,chp}^{class} = \left(f_{chp} \cdot hr_{chp}^{electric} \cdot (1+esc_y)^y + vom_{chp} + p_y^{CO2} \cdot ef_{chp} \cdot hr_{chp}^{electric}\right)$$

$$VC_{d,h,aux}^{class} = \left(f_{aux} \cdot hr_{aux}^{thermal} \cdot (1+esc_y)^y + vom_{aux} + p_y^{CO2} \cdot ef_{aux} \cdot hr_{aux}^{thermal}\right)$$

Ex-post adjustment to payments

It is important to mention that micro-CHPs and end-users react to prices estimated ex-ante by the market, while conventional power plants determine the final ex-post price in the system given the residual demand without micro-CHP electric contribution (see welfare expression above[117]). Therefore, when the price convergence criterion is reached, ex-ante and ex-post prices are the same (see Figure 5.1.4). However, when the iterative process oscillates and then exits the loop, there is a mismatch in the energy price between the last consecutive iterations.

To solve this problem we implemented an ex-post adjustment to the payments made by end-users for electricity purchase - i.e. adjustment to the electric costs incurred by customers. The methodology used is the following one:

- Electricity prices given to final customers and micro-CHP owners are fixed (i.e. ex-ante prices). Customers buy electricity at that price, while micro-CHP owners make their operational decisions using those prices.
- Having the aggregated micro-CHP electric production, it is possible to calculate the residual demand. Then we obtain a new set of system's marginal prices (i.e. ex-post prices) and the operation of the conventional power plants to these final system conditions.
- Payments previously made by final-consumers for electricity purchases are adjusted to account for price differences as shown below:

$$Consumer's\ adjustment_d = \left[-\sum_{h=1}\left(d_{d,h} \cdot (1+gr_y) - q_{d,h,chp}\right) \cdot \left(SRMP_{d,h}^{UP+GC,iter} - SRMP_{d,h}^{UP+GC,iter-1}\right)\right]; \forall d$$

Finally, the complete iterative process (as previously explained in Section 5.1.2.2. taking into consideration the final electricity price with uplift and network charges, customer classes and their aggregation, and payments adjustments because of convergence problems is depicted below in Figure 5.1.7.

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[117] In this expression, generator's surplus is calculated using prices of the current iteration, while consumer's surplus is calculated using prices from a previous iteration.

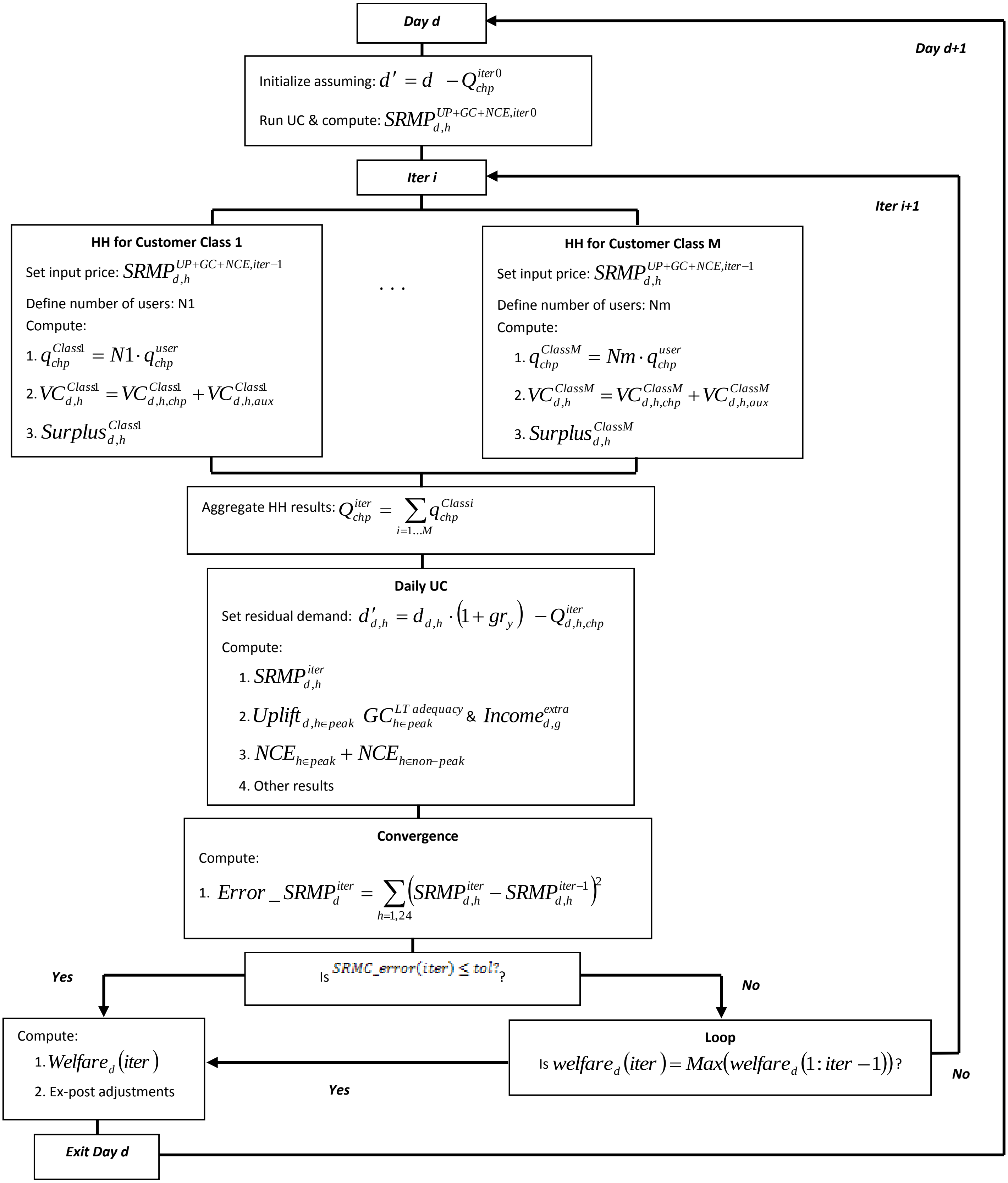

Figure 5.1.7: Short-term model complete iterative process

5.2. Long-term generation expansion model

A long-term capacity expansion model has been used to derive the energy portfolio of an electrical system that has been adapting to increasing levels of micro-CHPs during a time horizon of 20 years. This analysis has a twofold purpose: i) get the energy portfolio to be used as a reference case in the short-term analysis for a particular year (in particular, the last year of study period), and ii) understand long-term impacts of a large number of micro-CHPs in an energy system under particular market and regulatory conditions.

Regarding micro-CHP impacts in the long-run, we are particularly interested in understanding:

- Energy portfolio mix development and technologies being displaced by micro-CHP penetration.
- Impact of micro-CHP investment cost uncertainty on future technology penetration.
- Effects of carbon price on the deployment of micro-CHPs.
- Effects of fuel price uncertainty - at the retail level - on micro-CHP penetration.

5.2.1. Methodology description

Similar to the short-term problem, we adopt a system/central regulator approach who tries to determine an optimal energy portfolio given an increasing number of micro-CHPs throughout several years, under uncertain market and regulatory conditions.

The methodology considers:

- A long-term scope, i.e. 20 years time horizon for the analysis.
- Annual electric demand forecast for a system of characteristics similar to the New England system represented by 25 energy blocks for each winter and summer seasons.
- Annual heat demand per customer class, represented by 25 energy blocks per winter and summer seasons.
- Long-term electric capacity reserve requirements.
- A technology portfolio that includes electric generation power plants characterized by 12 technologies, distributed generation in the form of 3 micro-CHP technologies, and 1 type of distributed conventional heating system.
- Environmental regulations either in the form of emission restrictions or CO_2 price for every year on the time horizon.

The methodology does not include a network representation, and it is based on a single node at the distribution level.

The quantitative results we expect to get from this analysis are the following:

a. Planning and Operational outputs:
   - Installed capacity per technology for every year of the time horizon.
   - Power plants electric production per energy block, technology and year.
   - Micro-CHPs electric and heat production per customer class, energy block, technology and year.
   - Distributed heating systems heat production per customer class, energy block, technology and year.

b. Economic outputs:
   - System investment costs.
   - System operational costs.

We need to mention that given the time scope of the analysis, there is much uncertainty in demand growth, fuel prices, as well as future environmental regulations. To address this issue, we will work on different scenarios to understand how results from the generation expansion problem change under different conditions.

5.2.2. Problem formulation

The long-term capacity expansion problem is formulated as an optimization problem, where the objective function is to find the minimum total cost of producing electricity and heat over a time horizon of 20 years. The cost includes not only the annual operational costs, but also the capacity expansion investment costs necessary to cover both electricity and heat demands, in addition to electricity reserve requirements. Decision variables are the amount of capacity to install, electric production of conventional thermal units and micro-CHPs, and heat production of micro-CHPs and heating devices. In addition, operation constraints consider energy (electricity & heat) load balance, system capacity reserve requirements, CO_2 emissions, and installed capacity restrictions per technology (see Appendix B.1. Glossary of terms).

The optimization problem is solved using mixed integer linear (MIP) programming. It is developed through GAMS (General Algebraic Modeling System)[118] and solved using the CPLEX solver (91).

[118] GAMSIDE build: 5932 / 6015
Module: GAMS Base Module

Time structure

We consider a time horizon of 20 years. Expansion decisions are made annually, while operational decisions are made for every energy block of each year.

Assumptions

Some simplifications and assumptions adopted in the model:

- Electrical and heat loads are represented by load levels using a load duration curve of 50 energy bocks (details explained in the following section).
- System electrical load is based on historical data for the ISO-NE and projected using a growth rate.
- System heat load is not available. We use the heat profile for the classes of customers described in the short-term analysis section, and assume certain number of customers for each class for a region like New England.
- The electric system includes only thermal power plants. Micro-CHPs and distributed heating technologies (the warm-air type for simplicity) are included to supply heat demand in the system.
- No ramp rates or shut-down costs are included, neither start-up nor no-load costs.
- Fuel prices and demand growth rate are assumed for different scenarios.
- Formulation adopts a deterministic approach.

Inputs

a. System's electric & heat demand:

System electric load is based on the ISO-NE historical demand for year 2007(80)[119] with a growth rate applied annually. Data for a system's heat load is not available, so we constructed a load curve based on the heat load profiles simulated for two classes of customers[120]. For customer class 1, we assumed 3.2 million of users, while for customer class 2 we assumed 1.8 million of customers[121]. The chronological electric demand and aggregated heat load for both classes of customers, for every hour of the year are shown in Figure 5.2.1:

Lic date: Aug 1, 2008
Build: 22.8.1 WIN 6007.6015 VIS.

[119] See footnote #78.

[120] As explained in the short-term analysis, we used Enegy-10® to simulate the energy profiles for each class of customer. Refer to Section 5.1.

[121] The ISO-NE system has 6.5 million households and businesses with a total population of 14 million(111). From those, there are about 5.5million households in the New England region according to EIA's Residential Energy Consumption Survey(101). From these, 5.5 million use electricity, 2.7million use Natural Gas, and 2.5 million use fuel oil. For modeling purposes, we assumed that about 5 million of households has some sort of heating system.

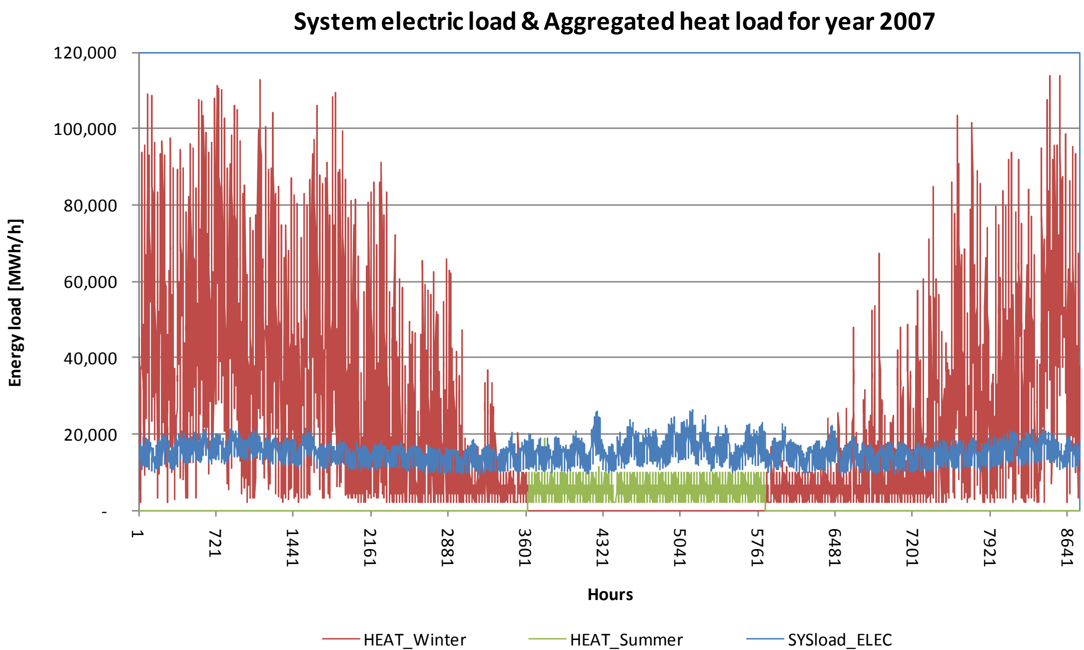

Figure 5.2.1: Chronological energy load curves for year 2007

For the long-term analysis we simplified these load curves using energy blocks defined for two periods. For the electrical load we defined two seasons:

- A winter season that extends from January to May, and September to December[122].
- A summer season that goes from June to August[123].

Then, we produced an electric load duration curve per season, where the heat load per customer class has been arranged according to the electric load order[124] (see Figure 5.2.2 and Figure 5.2.3):

[122] Winter goes from day 1 to 151, and day 244 to 365.
[123] Summer extends from day 152 to 243.
[124] From the figures we are able to see that the customer class' heat load is not coincident with the electric load of the system.

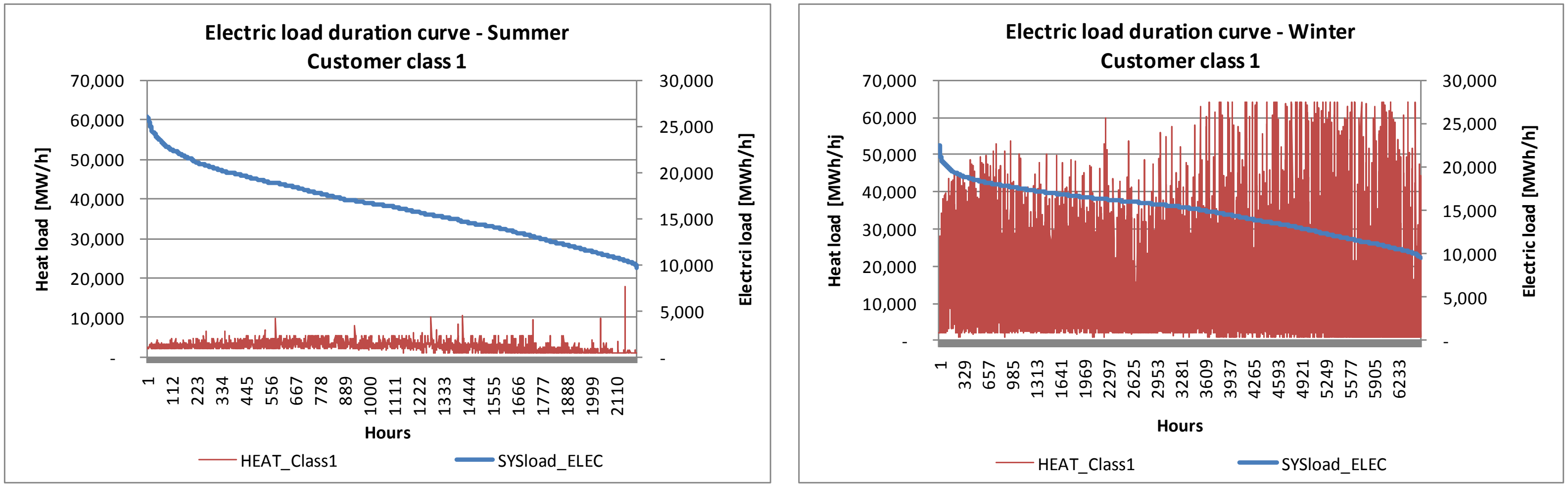

Figure 5.2.2: Electric load duration curve with heat load for customer class 1 per season

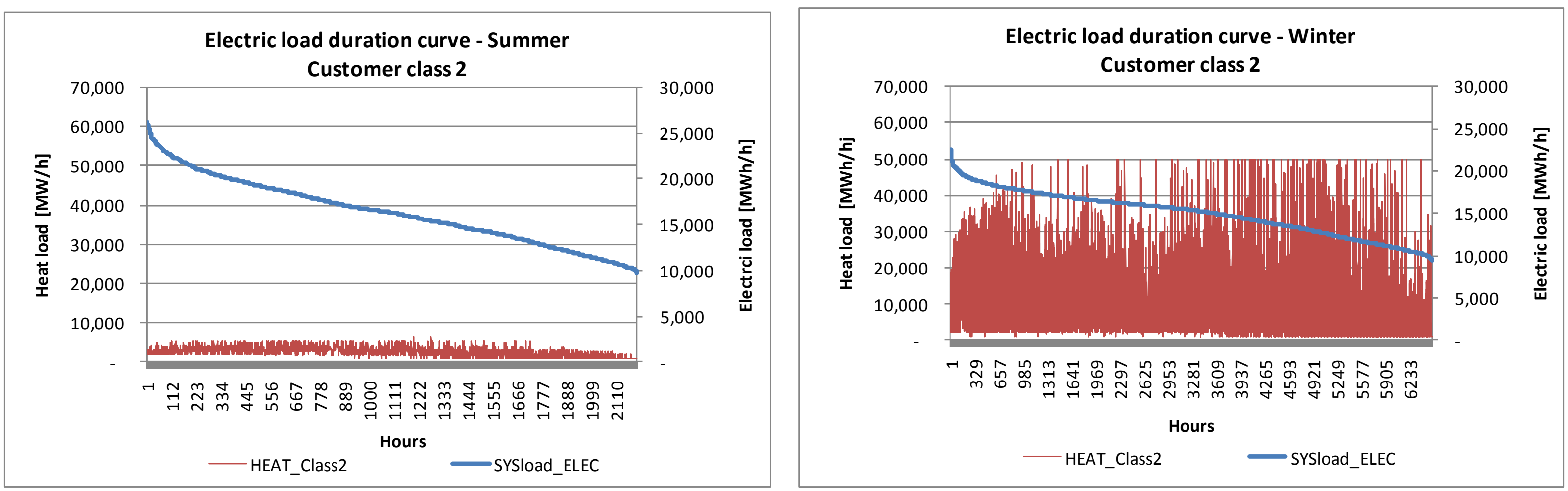

Figure 5.2.3: Electric load duration curve with heat load for customer class 2 per season

The electric load duration curve is simplified using 5 load levels per season:

Summer				Winter			
Block	Power	Hours	% Time	Block	Power	Hours	% Time
	[MW/bl]	[hr/bl]	[%/bl]		[MW/bl]	[hr/bl]	[%/bl]
b1	25,536	22	1.0%	**b1**	21,089	66	1.0%
b2	22,416	221	10.0%	**b2**	18,895	655	10.0%
b3	19,108	596	27.0%	**b3**	16,975	1,769	27.0%
b4	15,877	684	31.0%	**b4**	15,017	2,031	31.0%
b5	12,283	684	31.0%	**b5**	11,815	2,031	31.0%

Table 5.2-1: Electric load levels per season

Then, within each block we arrange the heat load in descending order - i.e. a heat load duration curve within each electric block - with the purpose of capturing the variations of heat within the heat load curve having in total 50 energy blocks (see Figure 5.2.4 and Figure 5.2.5). For the energy average values used in the LT model refer to "Appendix B.2. Electricity and heat values per energy block, season, and customer class".

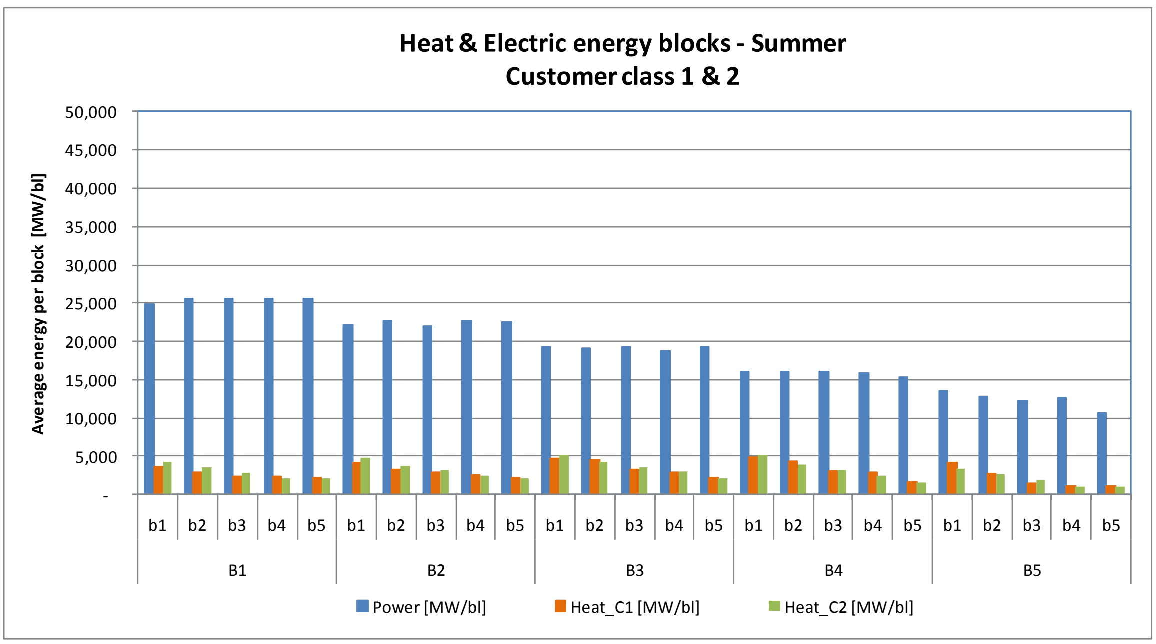

Figure 5.2.4: Summer heat and electric energy blocks per customer class

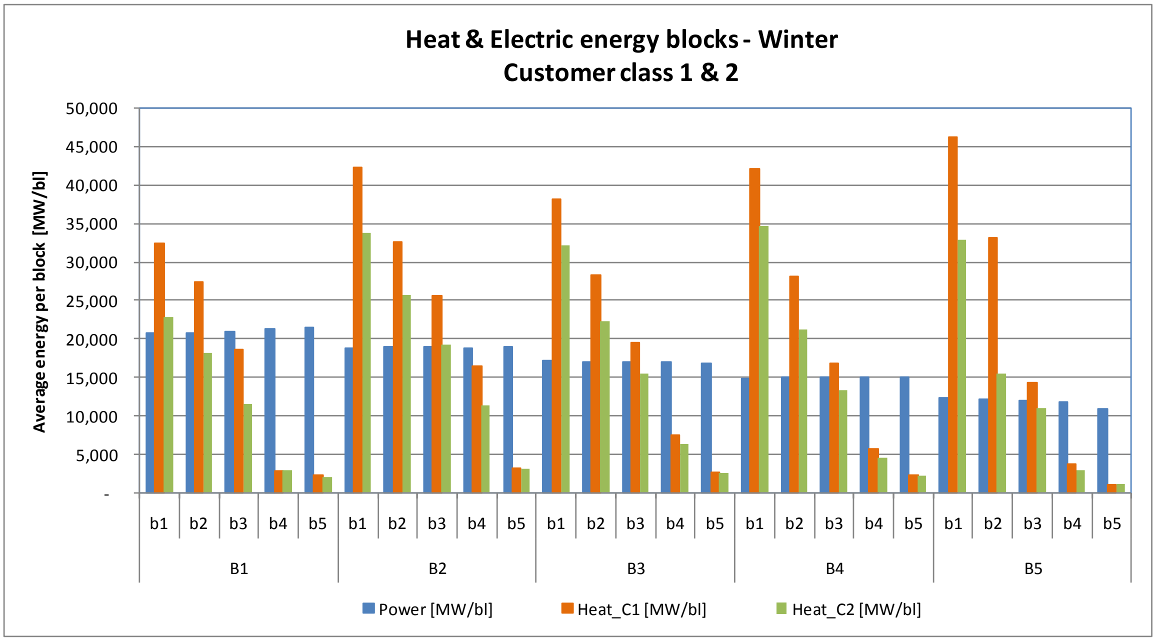

Figure 5.2.5: Winter heat and electric energy blocks per customer class

- From above we can see that using energy blocks as a simplification to the chronological energy loads allow us to capture the different patterns of electricity and heat. In particular we observe the following: Summer season has the highest values of electricity of the year, with peak values over 20,000MWe concentrated in electric blocks B1 and B2.

- Winter season has the highest values of heat of the year for both types of customers. We note that heat variation during winter is quite high compared to summer, where the heat is mostly lower than 5,000MWth per heat block.

- We note that heat peak demand is not coincident with peak electricity in winter. When looking at the simulations performed in Energy-10®, the heating equipments function well in advanced during the morning to reach the thermostat set point by 7am or 8am. Once the house has reached the required temperature, the heating devices regulate their operation to maintain the temperature during the day.

We need to clarify that the representation of energy demand is different for the long-term expansion problem and for the short-term operational model. In the first case, we opted for using energy blocks (see Figure 5.2.4 and Figure 5.2.5) because we needed to reduce the size of the problem, given the 20 years time horizon used in the model. In the second case, we used a one year chronological energy load (see Figure 5.2.1) because we wanted to model in more detail the daily operation of an electrical system that includes hourly commitment decisions for a given day, with the operation of micro-CHPs subject to hourly variations in price and energy.

Having defined 50 energy blocks, we then use a constant annual growth rate[125] to represent the demand increase over the time horizon:

Annual demand growth rate [p.u.]: gr_y

System electric demand per season p, block b, and year y [GW]: $d_{p,b}^{elec} \cdot (1+gr_y)^y$

System heat demand per season p, block b, customer class c, and year y [GW]: $d_{p,b,c}^{heat} \cdot (1+gr_y)^y$

Time duration of energy block per season p and block b [hr]: $du_{p,b}$

b. Technology characteristics:

Similar to the short-term model, we included thermo-electric generators, micro-CHPs and conventional heating system. Most of the technical and economic characteristics are based on data used in the EIA's Annual Energy Outlook 2010 (AEO2010) (3), information provided by manufacturers[126] and other sources[127].

For each technology, we include the following characteristics[128]:

Existent installed electric capacity per thermal technology g and distributed technology dms and customer class c [GW]: $\overline{p}_g^{elec}$, $\overline{p}_{dms,c}^{elec}$

Existent heating capacity per heating technology aux and customer class c [GW]: $\overline{p}_{aux,c}^{heat}$

Electric heat rate per thermal and distributed technology, and customer class c [MMBtu /kWh]: $hr_g^{elec}, hr_{dms,c}^{elec}$

Thermal heat rate per heating technology and customer class c [MMBtu/kWh]: $hr_{aux,c}^{heat}$

Availability factor per thermal technology g [129] [p.u.]: af_g

Availability factor per distributed & heating technology, per season [p.u.]: $af_{p,dms}$, $af_{p,aux}$

[125] Refer to footnote #78.
[126] See Chapters 2 and 3 for information on the technical characteristics used to model micro-CHP technologies.
[127] See footnote #81.
[128] We do not include minimum output, and ramp rate times for the thermal units.
[129] See footnote #83.

Regarding their economic characteristics, we include:

O&M variable cost per thermal, distributed & heating technology, per customer class c [$/kWh]: vom_g, $vom_{dms,c}$, $vom_{aux,c}$

Fuel cost per thermal, distributed & heating technology, per customer class c [$/MMBtu]: f_g, $f_{dms,c}$, $f_{aux,c}$

Annual investment and fixed cost per thermal, distributed & heating technology, per customer class c [$/kWyr][130]: fca_g, $fca_{dms,c}$, $fca_{aux,c}$

Economic lifetime per thermal, distributed & heating technology, per customer class c [yr]: $eclf_g$, $eclf_{dms,c}$, $eclf_{h,axu}$

Similar to Table 5.1-1, in Table 5.2-2 we show the values used for electric generation plants:

g		$\overline{p}_g^{elec}$ [GW]	fca_g [$/kWyr]	af_g [p.u.]	hr_g^{elec} [MMBtu/kWh]	f_g [$/MMBtu]	ef_g [ton/MMBtu]	vom_g [$/kWh]	$eclf_g$ [yr]
GasCT	n1	3.7	81.630	0.88	0.010788	7.720	0.0553	0.00352	30
GasCC	n2	11.5	112.424	0.87	0.007196	7.720	0.0553	0.00203	30
GasCCS	n3	0.0	216.205	0.87	0.008613	7.720	0.0055	0.00290	30
CoalOldUns	n4	3.0	219.338	0.85	0.009200	2.957	0.0926	0.00524	60
CoalOldScr	n5	0.0	253.330	0.85	0.009200	2.957	0.0926	0.00452	60
CofireOld	n6	0.0	260.182	0.85	0.009200	2.957	0.0926	0.00452	60
CoalNew	n7	0.0	418.072	0.85	0.008712	2.957	0.0926	0.00195	60
CofireNew	n8	0.0	424.925	0.85	0.008712	2.957	0.0926	0.00195	60
CoalIGCC	n9	0.0	299.499	0.85	0.008765	2.957	0.0926	0.00288	60
CoalCCS	n10	0.0	429.666	0.85	0.010781	2.957	0.0093	0.00437	60
OGS	n11	4.3	73.653	0.78	0.009230	14.987	0.0780	0.00383	50
Nuclear	n12	4.5	477.374	0.88	0.010488	0.670	-	0.00049	30

Table 5.2-2: Thermal plants characteristics used in the LT model

[130] The total annualized fixed cost per electric generation technology was calculated taking into account the capital cost and annual fixed O&M costs of each type of plant, using data from (81) an evaluation period of 20 years for all technologies, and a real discount rate of 8.5% (with a capital recovery factor of 10.6%/yr).
According to manufacturer's information, the purchase cost (without installation) of a boiler with heating capacity of about 20[kWth] ranges between 3,000 and 3,500 [$2007] plus an installation cost is about 2,000[$20007]. Thus, the unitary cost per unit of heat for a conventional heating system (like a boiler) was estimated to have an installed price of 241.95[$2007/kWth]. For micro-CHP we used an estimated installed cost of 7,000[$2007/kWe] for a system without auxiliary heating unit (such as boiler). Finally, for micro-CHPs and residential heating systems, we assumed a discount rate of 7% and an economic life of 20 years.

In Table 5.2-3 we show the values per micro-CHP technology[131]:

d,c		$\overline{p}^{elec}_{dms,c}$ [GW]	$fca_{dms,c}$ [$/kWyr]	af_{dms} [p.u.]	$hr^{elec}_{dms,c}$ [MMBtu/kWh]	$f_{dms,c}$ [$/MMBtu]	$ef_{dms,c}$ [ton/MMBtu]	$vom_{dms,c}$ [$/kWh]	$eclf_{dms,c}$ [yr]
Micro-CHP2.7	d1,c	0.0	660.750	0.98	0.013987	16.067	0.0553	0.0	20
Micro-CHP0.6	d2,c	0.0	660.750	0.98	0.006826	16.067	0.0553	0.0	20
Micro-CHP7.0	d3,c	0.0	660.750	0.98	0.031025	16.067	0.0553	0.0	20

Table 5.2-3: Micro-CHP technology characteristics per customer class

In Table 5.2-4 we show the values per conventional heating technology[132]:

aux,c		$\overline{p}^{heat}_{aux,c}$ [GW]	$fca_{aux,c}$ [$/kWyr]	af_{aux} [p.u.]	$hr^{heat}_{aux,c}$ [MMBtu/kWh]	$f_{aux,c}$ [$/MMBtu]	$ef_{aux,c}$ [ton/MMBtu]	$vom_{aux,c}$ [$/kWh]	$eclf_{aux,c}$ [yr]
Furnace	aux,c	15.0	22.839	0.98	0.003592	16.067	0.0553	0.0	20

Table 5.2-4 Conventional distributed heating system characteristic per customer class

To make the representation of the system closer to reality, the formulation considers that some installed electric capacity exists at the beginning of the planning exercise. Thus, the expansion problem takes into account the energy portfolio already in place and optimally evolves according to the market and regulatory conditions throughout the time horizon. Loosely based on the ISO-NE's thermal installed capacity requirements for year 2007-2008 (92)[133], we aggregated the requirements according to fuel and technology type (see Table 5.2-5) and then estimated the existent installed capacity per technology $\overline{p}^{elec}_{g}$ (see Table 5.2-2 above).

Unit type	Capacity requirements [MW]	% System [%]
Combined Cycle	11,365	37%
Coal Steam	2,745	9%
Nuclear steam	4,564	15%
Hydro	3,336	11%
Gas CT/Steam	3,615	12%
Oil CT/Steam	4,234	14%
Others	1,018	3%
Total System	**30,877**	**100%**

Table 5.2-5: Approximate ISO-NE's installed capacity requirements for year 2007.

[131] The electric heat rate per micro-CHP relates to the electric efficiency characteristic of each technology. For the model we are using the following values for electric and thermal efficiency:

d,c	Electric efficiency [%]	Thermal efficiency [%]
Micro-CHP2.7	66.8	24.4
Micro-CHP0.6	30.0	50.0
Micro-CHP7.0	78.0	11.0

[132] The thermal heat rate of the conventional heating unit corresponds to a thermal efficiency of 95%.
[133] See "Section 1 – Summaries, Table: 1.3 Summary of Summer Capability by Fuel/Unit Type" (without Purchases & Sales).

Regarding fuel prices, we use the same prices adopted during the short-term model, with the only difference that we apply an escalation factor of 0.5% per year to reflect fuel price increase over time. Using the prices reported in the 2010 Annual Energy Outlook for the Electric Power Sector and Residential Sector in New England for year 2007 (93), we used the following prices at the beginning of the study (see Table 5.2-6):

Fuel type	Fuel price [$2007/MMBtu]
Distillate fuel oil	14.987
Natural Gas	7.720
Steam Coal	2.957
Residential Natural Gas	16.067
Nuclear[134]	0.670

Table 5.2-6: Fuel prices used at the beginning of the LT analysis

c. Transmission and distribution costs:

Similar to the short-term model[135], in the long-term model we also include transmission and distribution costs in the system representation. The difference here is that we look at the problem from an economic rational perspective, which ideally yields the same result under either market or centrally planned conditions. A well adapted energy system of the future will take into account all the costs in the system, including any potential network costs savings of having micro-CHPs supplying electricity at a low voltage level (recall that we are not representing delivery networks in the model):

- *Charges paid by generators.* As the electricity supplied by power plants is withdrawn by final consumers at a low voltage node, generators need to produce more electricity to cover the losses in the transmission and distribution networks. Thus, we use a loss factor lf of 10% to reflect a variable cost increment of the conventional power plants operation. In addition, we assume that transportation costs are saved by the installation of micro-CHPs in the system which is equivalent to charge conventional generators the transportation costs. Therefore, we assume that 100% of the transmissions costs are paid by generators which are uniformly allocated according to the installed capacity in the system[136, 137]. (see Table 5.2-7).

[134] Fuel price for nuclear plants is taken from 2009 MIT's Update on the Cost of Nuclear Power (113) "Table 5: Base Case Assumptions and Inputs for the Levelized Cost of Electricity".
[135] Refer to "

Transmission & distribution network costs" in page #140.
[136] In the short-term model we assumed that 100% of the transmission costs are paid by end-users, as the goal is to transmit the most accurate electricity price to final consumers.
[137] Transmission demand charges paid by electric power generators were calculated based on the estimated electricity transmission cost for a NE-like system (refer to Table 5.1-8). This charge is estimated apriori and used as a constant amount in the long-term expansion model to get the optimal generation

Charges paid by generators	Energy charge [$/kWh]	Demand charge [$/kW-yr]
100% Transmission Cost	N/A	$tcp_g = \frac{(100\% TC)}{Installed\ Capacity^{system}}$
10% Energy Loss Factor	$lf \cdot (Variable\ Costs)$	N/A

Table 5.2-7: Charges paid by generators in the LT expansion model

- *Savings for micro-CHP owners.* In general, end-customers pay 100% of distribution costs allocated into energy and capacity charges[138]. However, if customers supply their own electricity with micro-CHPs they may incur in network savings either within their energy and/or capacity charges. Similar to the simplifications used in the short-term model we use energy and capacity charges, both in per units of energy instead of contracted demand:

Micro-CHP potential savings	Energy charge		Demand charge
	Peak [$/kWh peak]	Non-peak [$/kWh non-peak]	Peak [$/kWh peak]
100% Distribution Costs	$\frac{(50\% DC)\cdot \%^{peak}}{Energy^{peak}}$	$\frac{(50\% DC)\cdot (1-\%^{peak})}{Energy^{non-peak}}$	$\frac{(50\% DC)}{Energy^{peak}}$

Table 5.2-8: Micro-CHP potential distribution savings

Finally, based on these simplifications we obtained the energy and demand components that will be saved my micro-CHP owners[139] (see Table 5.2-9):

Micro-CHP potential savings	Energy charge		Demand charge
	Peak [$/kWh peak]	Non-peak [$/kWh non-peak]	Peak [$/kWh peak]
Distribution Costs	0.0230	0.0165	0.1188

Table 5.2-9: Calculated micro-CHP potential distribution savings

Where $dce_{b\in peak} = 0.1418\ [\$/kWh\ peak]$ and $dce_{b\in non-peak} = 0.0165\ [\$/kWh\ non-peak]$.

expansion. It is calculated based solely on the installed capacity of the system at the beginning of the expansion analysis:

$$Transmission\ demand\ charge = tcp_g = \frac{100\% \cdot TC}{Installed\ capacity\ system} = \frac{940\ [MM\$]}{27{,}000\ [MW]} \approx 35\ [\$/kW]$$

We recognize that this approach does not capture the fact that the system has a very varied portfolio of technologies, where some have a small proportion of installed capacity in the system and they are operated only some hours of the year. For example, peaking OCGT plants versus base load nuclear plants.

[138] Refer to "

Transmission & distribution network costs" in page #140.

[139] Refer to Table 5.1-5 for an explanation on the numbers being used in the calculations.

d. CO2 price and emissions:

Emissions are very different depending on the type of technology and fuel used by that technology. We account for emissions from thermal power plants, micro-CHPs and conventional heating devices per customer class that supply electricity and heat to the energy system[140]. Similar to the short-term model, emissions are included in the model either through an emission constraint or an additional cost in the objective function depending on the scenario we are analyzing:

CO2 emission rate [ton/MMBtu]: ef_g , $ef_{dms,c}$, $ef_{aux,c}$

CO2 price [$/ton]: p_y^{CO2}

Based on the MIT Joint Program Report 173 (94), we took CO2 emissions trajectory and CO2 prices reported by three core cases[141]: i) Case Bmt287 holds emissions flat at 2008 levels, ii) Case Bmt203 cuts emissions to 50% below 1990 by 2050, and iii) Case Bmt167 cuts emissions to 80% below 1990 levels by 2050[142] (see Table 5.2-10).

Year	Case 167bmt		Case 203bmt		Case 287bmt	
	CO2 Emissions (GT CO2-e)	CO2-E Price (2005$/tCO2-e)	CO2 Emissions (GT CO2-e)	CO2-E Price (2005$/tCO2-e)	CO2 Emissions (GT CO2-e)	CO2-E Price (2005$/tCO2-e)
2000	5.845	0.00	5.845	0.00	5.845	0.00
2010	5.903	0.00	5.903	0.00	5.903	0.00
2020	4.414	70.68	4.918	47.78	6.199	6.30
2030	3.821	104.62	4.711	70.73	6.547	9.33
2040	3.243	154.86	4.567	104.69	7.237	13.81
2050	3.004	229.23	4.054	154.97	8.060	20.45

Table 5.2-10: Emissions targets and prices from MIT Joint Program Report 173

Based on these results, a CO2 price trajectory is estimated as using an annual rate of 4% and year 2050 as the final target. Therefore, the CO2 price for the last year of the time horizon is given by:

$$p_y^{CO2} = \frac{p_{2050}^{CO2}}{(1+4\%)^{(2050-y)}}$$

Where *y* is year 2027.

[140] See footnote #93.
[141] See Appendix A of the MIT Joint Program Report 173 "The Cost of Climate Policy in the United States." Report available at http://globalchange.mit.edu/files/document/MITJPSPGC_Rpt173_AppendixA.xls.
[142] Cases name are based on emissions targets that would be available between 2012 & 2050 in billions of metric tons (bmt).

Then, assuming a linear CO2 price trajectory from year 2007 to year 2027 for the three different scenarios, we estimate the annual prices as shown in Table 5.2-11 (exogenously fixed for every year of the simulation period[143]):

Year	**Case high** [2007$/tCO2]	**Case medium** [2007$/tCO2]	**Case low** [2007$/tCO2]
2008	20.00	31.68	0.00
2009	24.14	32.95	0.00
2010	28.29	34.27	0.00
2011	32.43	35.64	0.00
2012	36.58	37.07	0.00
2013	40.72	38.55	0.00
2014	44.87	40.09	0.00
2015	49.01	41.69	0.00
2016	53.15	43.36	0.00
2017	57.30	45.10	0.00
2018	61.44	46.90	0.00
2019	65.59	48.78	0.00
2020	69.73	50.73	0.00
2021	73.87	52.76	0.00
2022	78.02	54.87	0.00
2023	82.16	57.06	0.00
2024	86.31	59.34	0.00
2025	90.45	61.72	0.00
2026	94.60	64.19	0.00
2027	98.74	66.75	0.00

Table 5.2-11: CO2 prices used in the LT model

e. Other electric system parameters:

Reserve requirement assumed to be 10% of peak demand block: $opr = 10\%$

Cost of non-served energy: $nse^{cost} = 8\ [\ \$/kWh\ ]$

Cost of excess energy[144]: $exc^{cost} = 100\ [\ \$/kWh\ ]$

Cost of non-served or excess of power reserve[145]: $nsp^{cost} = 100\ [\ \$/kW\ ]$

[143] We assumed CO2 prices at the beginning of the study period, even though the prices reported in the "MIT Joint Program Report 173" were 0 [$/tCO2] up to year 2010.
[144] This term is used to avoid unfeasible solutions, like having excess of energy in an electric system. This variable is penalized in the objective function with a high value.
[145] See footnote #144.

Operation variables for every year

The simple long-term generation expansion model has continuous and binary variables for every year and every energy block within the year:

Electric installed capacity of thermal unit g for year y [GW]: $IC_{y,g}^{elec}$

Electric generation of thermal unit g for year y, block b and season p [GW]: $Q_{y,b,p,g}^{elec}$

Electric installed capacity of micro-CHP unit dms, per customer class c, for year y [GW]: $IC_{y,dms,c}^{elec}$

Electric generation of micro-CHP unit dms , per customer class c, for year y, block b and season p [GW]: $Q_{y,b,p,dms,c}^{elec}$

Heat installed capacity of heating unit aux, per customer class c, for year y [GW]: $IC_{y,aux,c}^{heat}$

Heat generation of heating unit aux, per customer class c, for year y, block b and season p [GW]: $Q_{y,b,p,aux,c}^{heat}$

Non-served energy for year y, block b and season p [GW]: $Q_{y,b,p,nse}^{elec}$

Non-served reserve power for year y and season p [GW]: $P_{y,p,nse}^{elec}$

Excess energy for year y, block b and season p [GW]: $Q_{y,b,p,excess}^{elec}$

Excess reserve power for year y and season p [GW]: $P_{y,p,excess}^{elec}$

Connection decision of thermal unit g for year y, block b and season b [0/1]: $Z_{y,b,p,g}$

Connection decision of micro-CHP unit dms and per customer class c [0/1]: $IT_{dms,c}$

Constraints

In the model we include energy (electricity & heat) balance constraints, long-term reserve requirements, yearly installed capacity limitations per technology, and operational restrictions.

a. Electric generation and load balance for every energy block:

The sum of thermal power plants generation and electric production from micro-CHP technologies, in addition to non-served energy, should equal electric demand in the system for every energy block:

$$\sum_{g} Q_{y,b,p,g}^{elec} + \sum_{dms,c} Q_{y,b,p,dms,c}^{elec} + Q_{y,b,p,nse}^{elec} - Q_{y,b,p,excess}^{elec} = d_{p,b}^{elec} \cdot (1+gr_y)^y \quad ;\forall y,b,p$$

b. Heat production and load balance for every energy block, per customer class:

The sum of heat production by micro-CHPs and heat coming from conventional heating devices has to be equal to heat demand per customer class, for every energy block. Here the heat produced by micro-CHPs is obtained using the heat-to-power ratio (HPR) characteristic of each technology, where for every unit of electricity the micro-CHP produces *HPR* units of heat:

$$\sum_{dms} hpr_{dms,c} \cdot Q_{y,b,p,dms,c}^{elec} + \sum_{aux} Q_{y,b,p,aux,c}^{heat} = d_{p,b,c}^{heat} \cdot (1+gr_y)^y \quad ;\forall y,b,p,c$$

c. Long-term reserve requirement for every season:

Reserve requirements for every year are assumed to be 10% of the electrical peak load level of each season. The committed maximum output of thermal units considering a linear retirement of existent installed capacity and an availability factor, in addition to the maximum electric output of micro-CHPs has to be greater that the reserve requirements during peak times:

$$\begin{aligned}
&\sum_{g} \left(\overline{p}_{g}^{elec} \cdot \left(1 - \frac{y}{eclf_g}\right) \cdot Z_{y,'bpeak',p,g} + \sum_{k \le y} IC_{k,g}^{elec} \cdot Z_{k,'bpeak',p,g} \right) \cdot af_g \\
&+ \sum_{dms,c} \left(\overline{p}_{dms,c}^{elec} \cdot \left(1 - \frac{y}{eclf_{dms,c}}\right) \cdot IT_{dms,c} + \sum_{k \le y} IC_{k,dms,c}^{elec} \cdot IT_{dms,c} \right) \cdot af_{p,dms} \\
&+ P_{y,p,nse}^{elec} - P_{y,p,excess}^{elec} \\
&\ge (1+opr) \cdot d_{p,'bpeak'}^{elec} \cdot (1+gr_y)^y \quad ;\forall y,p
\end{aligned}$$

In this expression, the linear retirement of the capacity installed at the beginning of the expansion exercise is not applied to nuclear power plants. Given the uncertainty on the future development of this particular technology, we have adopted in the model neither adding new plant nor retiring old plants.

d. Operation limits for every energy block:

Electric production from thermal power plants and micro-CHPs, and heat production from conventional heating systems have to be lower than the installed capacity of each technology[146]:

$$Q^{elec}_{y,b,p,g} \leq \left[\overline{p}^{elec}_{g} \cdot \left(1 - \frac{y}{eclf_{g}}\right) \cdot Z_{y,b,p,g} + \sum_{k \leq y} IC^{elec}_{k,g} \cdot Z_{k,b,p,g} \right] \cdot af_{g} \quad ; \forall y, b, p, g$$

$$Q^{elec}_{y,b,p,dms,c} \leq \left[\overline{p}^{elec}_{dms,c} \cdot \left(1 - \frac{y}{eclf_{dms,c}}\right) \cdot IT_{dms,c} + \sum_{k \leq y} IC^{elec}_{k,dms} \cdot IT_{dms,c} \right] \cdot af_{p,dms} \quad ; \forall y, b, p, dms, c$$

$$Q^{heat}_{y,b,p,aux,c} \leq \left[\overline{p}^{heat}_{auc,c} \cdot \left(1 - \frac{y}{eclf_{aux,c}}\right) + \sum_{k \leq y} IC^{heat}_{k,aux,c} \right] \cdot af_{p,aux} \quad ; \forall y, b, p, aux, c$$

e. Electric production in consecutive load levels:

Electric output of thermal power plants during a low load level is lower than the output during a high load level. To enforce this in our model, we need to consider the fact that the electric load duration curve was defined using 5 electrical energy blocks *B* per season (in decreasing order), each then subdivided into 5 heating energy blocks *b* (also in decreasing order). This manipulation results in a load curve where the first five blocks have an average electric power higher than the following 5 blocks, but the first five blocks may not have a decreasing order.

For example, in Figure 5.2.6 we can see that the average electric power within block *B1* is higher than the average power within block *B2*. However, sub-blocks *b1* up to *b5* within block *B1* do not follow a decreasing order from the electrical point of view.

[146] Linear retirement of the capacity installed at the beginning of the expansion exercise is not applied to nuclear power plants.

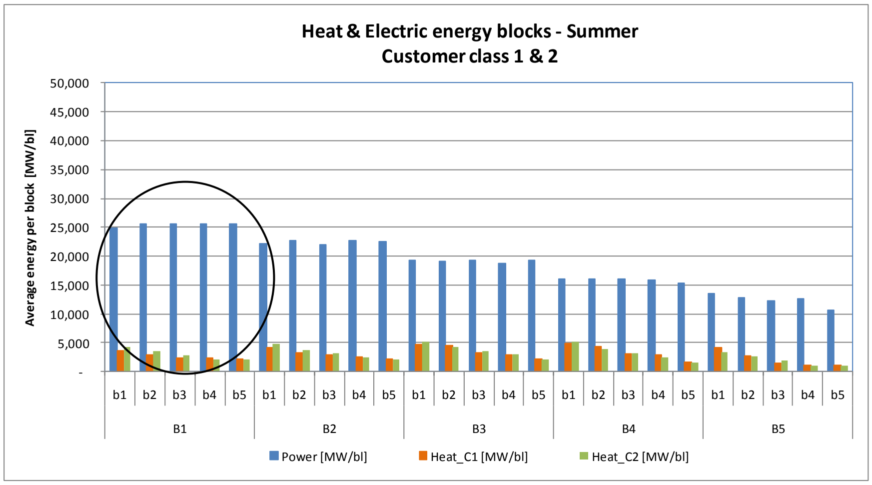

Figure 5.2.6: Electric energy blocks

Therefore, to implement the requirement that the electric output of a conventional power plant has to follow a decreasing order per energy block, we used the following restriction:

$$Q_{y,b+5,p,g}^{elec} \leq Q_{y,b,p,g}^{elec} \quad ;\forall y,b,p,g$$

f. Installed capacity limitations for every year:

We include limitations on the amount of new capacity that each technology can install within the electric system, taking into consideration a linear retirement of the capacity existing at the beginning of the analysis.

- Micro-CHP electric incremental installed capacity is lower than 1000MW per year:

$$IC_{y,dms,c}^{elec} \leq 1.0 \;\; ;\forall y \leq 20$$

- Nuclear new capacity is not allowed during the time horizon. In addition, capacity retirement for nuclear technology is not allowed either:

$$IC_{y,g=nuclear}^{elec} = 0.0 \;\; ;\forall y \leq 20, \;\; g = nuclear$$

- Old coal power plants with no scrubbers are not allowed to have new capacity in the system. Existent capacity at the beginning of the time horizon is allowed, but linear retirement is made every year:

$$IC_{y,g=CoalOldUns}^{elec} = 0.0 \;\; ;\forall y, \;\; g = CoalOldUns$$

- Gas and Coal technologies with carbon capture and sequestration are allowed to have limited new capacity in the system after year 5, with capacity limit of 200MW per year:

$$IC_{y,g=GasCCS}^{elec} = 0.0 \;\; ;\forall y \leq 5, \;\; g = GasCCS$$

$$IC_{y,g=GasCCS}^{elec} \leq 0.2 \;\; ;\forall y > 5, \;\; g = GasCCS$$

$$IC^{elec}_{y,g=CoalCCS} = 0.0 \;;\forall y \le 5,\; g = CoalCCS$$

$$IC^{elec}_{y,g=CoalCCS} \le 0.2 \;;\forall y > 5,\; g = CoalCCS$$

- For other thermal technologies, new capacity is allowed limited up to than 1000MW per year:

$$IC^{elec}_{y,g} \le 1.0 \;;\forall y > 1,\; g \ne Nuclear, CoalOldUns, GasCCS, CoalCCS$$

g. Micro-CHP selection per customer class:

Each customer class is allowed to have a combination of conventional heating system and, at most, only one type of micro-CHP technology for the entire time horizon.

$$\sum_{dms} IT_{dms,c} \le 1 \;;\forall c$$

Objective function

The goal of the problem is to minimize total investment costs and operational costs of providing electricity & heat to a system, including the costs of non-served energy and non-served reserve requirements. The objective function is defined for the 20 years time horizon in terms of the present value of the costs incurred during different years[147].

a. Investment costs for time horizon:

- For thermal power plants we include annualized capital costs plus an electric transmission cost (see Table 5.2-7) in the form of capacity charge[148] characteristic to each technology type:

$$\sum_{y}\sum_{g}\left[\left(fca_g + tcp_g\right)\cdot IC^{elec}_{y,g} \cdot \sum_{k \le TH-y+1}\left(\frac{1}{1+dr}\right)^{y+k-1}\right]$$

- For micro-CHPs we include annualized capital costs and a factor that reflects capital costs reduction because of capital investment subsidy, technology improvements or mass production:

$$\sum_{y}\sum_{dms}\sum_{c}\left[fca_{dms,c}\cdot\left(1-\%^{reduction}\right)\cdot IC^{elec}_{y,dms,c}\cdot \sum_{k \le TH-y+1}\left(\frac{1}{1+dr}\right)^{y+k-1}\right]$$

[147] We used a real discount rate of 8.5% for all calculations.

[148] Refer to "Transmission and distribution costs:" in page #161.

- For heating technologies we include the annualized capital costs per installed capacity of heat:

$$\sum_{y}\sum_{aux}\sum_{c}\left[fca_{aux,c}\cdot IC^{heat}_{y,auc,c}\cdot \sum_{k\leq TH-y+1}\left(\frac{1}{1+dr}\right)^{y+k-1}\right]$$

b. Variable costs for time horizon:

- For thermal power plants we include fuel costs, potential CO2 emission costs, and variable O&M costs. In addition, as explained in previously, we increase variable costs through an energy loss factor lf of 10% that reflects network losses incurred by centralized power plants to supply demand at lower voltage levels:

$$\sum_{y,b,p,g}\left(Q^{elec}_{y,b,p,g}\cdot du_{b,p}\cdot\left(f_g\cdot hr^{elec}_g\cdot\left(1+esc_y\right)^y+vom_g+p^{CO2}_y\cdot ef_g\cdot hr^{elec}_g\right)\cdot\left(1+lf\right)\cdot\left(\frac{1}{1+dr}\right)^y\right)$$

- For micro-CHPs we include fuel costs, cost of emissions, and variable O&M costs. In addition, we assume that micro-CHP owners incur in distribution network savings (see Table 5.2-9) due to on-site electricity production[149]:

$$\sum_{y,b,p,dms,c}\left(Q^{elec}_{y,b,p,dms,c}\cdot du_{b,p}\cdot\left(\begin{array}{l} f_{dms,c}\cdot hr^{elec}_{dms,c}\cdot\left(1+esc_y\right)^y+vom_{dms,c}+p^{CO2}_y\cdot ef_{dms,c}\cdot hr^{elec}_{dms,c}\\ -dce_{b\in peak}-dce_{b\in non-peak}\end{array}\right)\cdot\left(\frac{1}{1+dr}\right)^y\right)$$

- For heating technologies we include fuel costs, cost of emissions, and variable O&M costs due to the production of heat:

$$\sum_{y,b,p,aux,c}\left(Q^{heat}_{y,b,p,aux,c}\cdot du_{b,p}\cdot\left(f_{aux,c}\cdot hr^{heat}_{aux,c}\cdot\left(1+esc_y\right)^y+vom_{aux,c}+p^{CO2}_y\cdot ef_{aux,c}\cdot hr^{heat}_{aux,c}\right)\cdot\left(\frac{1}{1+dr}\right)^y\right)$$

c. Non-served energy & reserve power costs for every day:

Finally, within the objective function we add the additional cost the system may incur for non-served energy (or excess) and non-served reserve requirements (or excess):

$$\sum_{y,b,p}\left(Q^{elec}_{y,b,p,nse}\cdot nse^{cost}+Q^{elec}_{y,b,p,excess}\cdot exc^{cost}\right)\cdot du_{b,p}$$
$$+\sum_{y,p}\left(P^{elec}_{y,p,nse}+P^{elec}_{y,p,excess}\right)\cdot nsp^{cost}$$

[149] As explained Section 5.1, since planning and operational decisions are made at a low voltage level, micro-CHPs owners may incur in network savings for not buying electricity.

Complete formulation

Finally, the long-term generation expansion model for the entire time horizon being studied (20 years overall) is formulated as follows:

$$
\begin{aligned}
&\mathit{Minimize} \\
&\sum_{y}\sum_{g}\left[\left(fca_{g}+tcp_{g}\right)\cdot IC_{y,g}^{elec}\cdot\sum_{k\le TH-y+1}\left(\frac{1}{1+dr}\right)^{y+k-1}\right] \\
&+\sum_{y}\sum_{dms}\sum_{c}\left[fca_{dms,c}\cdot\left(1-\%^{reduction}\right)\cdot IC_{y,dms,c}^{elec}\cdot\sum_{k\le TH-y+1}\left(\frac{1}{1+dr}\right)^{y+k-1}\right] \\
&+\sum_{y}\sum_{aux}\sum_{c}\left[fca_{aux,c}\cdot IC_{y,auc,c}^{heat}\cdot\sum_{k\le TH-y+1}\left(\frac{1}{1+dr}\right)^{y+k-1}\right] \\
&+\sum_{y,b,p,g}\left(Q_{y,b,p,g}^{elec}\cdot du_{b,p}\cdot\left(f_{g}\cdot hr_{g}^{elec}\cdot\left(1+esc_{y}\right)^{y}+vom_{g}+p_{y}^{CO2}\cdot ef_{g}\cdot hr_{g}^{elec}\right)\cdot\left(1+lf\right)\cdot\left(\frac{1}{1+dr}\right)^{y}\right) \\
&+\sum_{y,b,p,dms,c}\left(Q_{y,b,p,dms,c}^{elec}\cdot du_{b,p}\cdot\begin{pmatrix}f_{dms,c}\cdot hr_{dms,c}^{elec}\cdot\left(1+esc_{y}\right)^{y}+vom_{dms,c}+p_{y}^{CO2}\cdot ef_{dms,c}\cdot hr_{dms,c}^{elec}\\-dce_{b\in peak}-dce_{b\in non-peak}\end{pmatrix}\cdot\left(\frac{1}{1+dr}\right)^{y}\right) \\
&+\sum_{y,b,p,aux,c}\left(Q_{y,b,p,aux,c}^{heat}\cdot du_{b,p}\cdot\left(f_{aux,c}\cdot hr_{aux,c}^{heat}\cdot\left(1+esc_{y}\right)^{y}+vom_{aux,c}+p_{y}^{CO2}\cdot ef_{aux,c}\cdot hr_{aux,c}^{heat}\right)\cdot\left(\frac{1}{1+dr}\right)^{y}\right) \\
&+\sum_{y,b,p}\left(Q_{y,b,p,nse}^{elec}\cdot nse^{cost}+Q_{y,b,p,excess}^{elec}\cdot exc^{cost}\right)\cdot du_{b,p} \\
&+\sum_{y,p}\left(P_{y,p,nse}^{elec}+P_{y,p,excess}^{elec}\right)\cdot nsp^{cost}
\end{aligned}
$$

$s.t.$

$$\sum_{g} Q^{elec}_{y,b,p,g} + \sum_{dms,c} Q^{elec}_{y,b,p,dms,c} + Q^{elec}_{y,b,p,nse} - Q^{elec}_{y,b,p,excess} = d^{elec}_{p,b} \cdot (1+gr_y)^y \quad ;\forall y,b,p$$

$$\sum_{dms} hpr_{dms,c} \cdot Q^{elec}_{y,b,p,dms,c} + \sum_{aux} Q^{heat}_{y,b,p,aux,c} = d^{heat}_{p,b,c} \cdot (1+gr_y)^y \quad ;\forall y,b,p,c$$

$$\begin{pmatrix} \sum_{g}\left(\overline{p}^{elec}_{g} \cdot \left(1-\frac{y}{eclf_g}\right) \cdot Z_{y,'bpeak',p,g} + \sum_{k\le y} IC^{elec}_{k,g} \cdot Z_{k,'bpeak',p,g} \right) \cdot af_g \\ + \sum_{dms,c}\left(\overline{p}^{elec}_{dms,c} \cdot \left(1-\frac{y}{eclf_{dms,c}}\right) \cdot IT_{dms,c} + \sum_{k\le y} IC^{elec}_{k,dms,c} \cdot IT_{dms,c} \right) \cdot af_{p,dms} \\ + P^{elec}_{y,p,nse} - P^{elec}_{y,p,excess} \end{pmatrix} \ge (1+opr) \cdot d^{elec}_{p,'bpeak'} \cdot (1+gr_y)^y \quad ;\forall y,p$$

$$\begin{pmatrix} \sum_{b,p,g} Q^{elec}_{y,b,p,g} \cdot du_{p,b} \cdot ef_g \cdot hr^{elec}_{g} \\ + \sum_{b,p,dms,c} Q^{elec}_{y,b,p,dms,c} \cdot du_{p,b} \cdot ef_{dms,c} \cdot hr^{elec}_{dms,c} \\ + \sum_{b,p,aux,c} Q^{heat}_{y,b,p,aux,c} \cdot du_{p,b} \cdot ef_{aux,c} \cdot hr^{heat}_{aux,c} \end{pmatrix} \le CO2^{elec\&heat}_{y} \quad ;\forall y$$

$$Q^{elec}_{y,b,p,g} \le \left[\overline{p}^{elec}_{g} \cdot \left(1-\frac{y}{eclf_g}\right) \cdot Z_{y,b,p,g} + \sum_{k\le y} IC^{elec}_{k,g} \cdot Z_{k,b,p,g} \right] \cdot af_g \quad ;\forall y,b,p,g$$

$$Q^{elec}_{y,b,p,dms,c} \le \left[\overline{p}^{elec}_{dms,c} \cdot \left(1-\frac{y}{eclf_{dms,c}}\right) \cdot IT_{dms,c} + \sum_{k\le y} IC^{elec}_{k,dms} \cdot IT_{dms,c} \right] \cdot af_{p,dms} \quad ;\forall y,b,p,dms,c$$

$$Q^{heat}_{y,b,p,aux,c} \le \left[\overline{p}^{heat}_{auc,c} \cdot \left(1-\frac{y}{eclf_{aux,c}}\right) + \sum_{k\le y} IC^{heat}_{k,aux,c} \right] \cdot af_{p,aux} \quad ;\forall y,b,p,aux,c$$

$$Q^{elec}_{y,b+5,p,g} \le Q^{elec}_{y,b,p,g} \quad ;\forall y,b,p,g$$

$$\sum_{dms} IT_{dms,c} \le 1 \quad ;\forall c$$

$$IC^{elec}_{y,g=nuclear} = 0.0 \quad ;\forall y \le 20,\ g = nuclear$$

$$IC^{elec}_{y,g=CoalOldUns} = 0.0 \quad ;\forall y,\ g = CoalOldUns$$

$$IC^{elec}_{y,g=GasCCS} = 0.0 \quad ;\forall y \le 5,\ g = GasCCS$$

$$IC^{elec}_{y,g=GasCCS} \le 0.2 \quad ;\forall y > 5,\ g = GasCCS$$

$$IC^{elec}_{y,g=CoalCCS} = 0.0 \quad ;\forall y \le 5,\ g = CoalCCS$$

$$IC^{elec}_{y,g=CoalCCS} \le 0.2 \quad ;\forall y > 5,\ g = CoalCCS$$

$$IC^{elec}_{y,g} \le 1.0 \quad ;\forall y > 1,\ g \ne Nuclear, CoalOldUns, GasCCS, CoalCCS$$

$$IC^{elec}_{y,g}, IC^{elec}_{y,dms,c}, IC^{heat}_{y,aux,c} \ge 0 \quad ;\forall y,g,dms,aux,c$$

$$Q^{elec}_{y,b,p,g}, Q^{elec}_{y,b,p,dms,c}, Q^{heat}_{y,b,p,aux,x} \ge 0 \quad ;\forall y,b,p,g,dms,aux,c$$

$$Q^{elec}_{y,b,p,nse}, Q^{elec}_{y,b,p,excess} \ge 0 \quad ;\forall y,b,p$$

$$P^{elec}_{y,p,nse}, P^{elec}_{y,p,excess} \ge 0 \quad ;\forall y$$

$$Z_{y,b,p,g}, IT_{dms,c} \in \{0,1\} \quad ;\forall y,b,p,g,dms,c$$

CHAPTER 6

LARGE-SCALE DEPLOYMENT MODELS RESULTS

Based on the methodology described in previous chapters, in this chapter we will focus on the quantitative outcomes of a varied number of scenarios used to understand the effects of a large penetration of micro-CHPs within a particular energy system in the long and short terms.

First, we will introduce the results from the long-term analyses based on the evolution of the energy system in a 20 year-time period with an ongoing deployment of micro-CHPs. Using different micro-CHP capital cost, natural gas retail price and CO2 price conditions, we will center the analysis on the effects of micro-CHPs on displaced conventional electric power technologies, avoided cumulative CO2 emissions, and the economic and regulatory conditions that may favor the deployment of the different micro-CHP technologies.

Then, we follow with the results obtained from the short-term analysis which is based on the operation of the energy system during the last year of the time-horizon. A unit commitment model (used to represent the operation of electric power plants) is integrated with an operational model at the residential level that is used to represent the economic operation of micro-CHPs for different classes of customers. The analysis in this case focuses on particular system-wide and household metrics to quantify the impact of having a large number of micro-CHPs. These metrics include energy production costs, CO2 emissions, energy efficiency and peak load reductions during summer, for the particular year being studied and compared against the case of not having micro-CHPs. In addition, we also study the response of micro-CHPs when residential customers receive different electricity retail rates such as flat, time-of-use, and hourly rates.

6.1. Results from the Long-Term Generation Expansion Model

As we commented earlier, the long-term capacity expansion model has a twofold purpose. First, obtain the energy portfolio to be used as a reference case in the short-term analysis for a particular year. Second, understand the long-term impacts of a large number of micro-CHPs in a particular energy system. Regarding the second point, we are interested in understanding:

- The electric energy portfolio evolution over time with increasing micro-CHP penetration, in terms of identifying those technologies being displaced by micro-CHPs under investment cost, carbon price, and retail fuel price uncertainty.
- The system's technology choice for meeting residential heat requirements, when having micro-CHPs and conventional heating equipments as alternatives.
- The system's CO2 emissions throughout the 20 years time period with increasing levels of micro-CHPs, considering emissions from producing electricity and heat.

To answer these questions, we performed two types of analyses: i) Sensitivity analysis to micro-CHP capital cost under different CO2 price & natural gas retail price scenarios, and ii) Sensitivity analysis to natural gas retail price under different capital cost & CO2 price scenarios.

6.1.1. Reference case

First, we will explain the type of results we obtained from the LT generation expansion model, focusing on the particular case of having about 10% micro-CHP penetration at the end of time period under high CO2 price and high natural gas retail price conditions[150].

In Figure 6.1.1 and Figure 6.1.2 we show the time evolution of the electric energy portfolio in terms of electric installed capacity and electric production respectively. Clearly we see that a high CO2 price allows the development of clean technologies such as Gas CCS and Coal CCS[151]. In order to have a 10% micro-CHP penetration at the end of the time horizon, the capital cost has to be close to 4,500 [$/kWe], i.e. 2,500 [$/kWe] down from the reference price we assumed throughout the study. From the figures we see that there are two types of micro-CHPs within the electric mix, each with about 5% of the electric capacity portfolio and close to 9% of the electric production portfolio. Each micro-CHP type corresponds to each customer class C1 and C2 defined in the model according to their heating demands (see d1.c1uCHP2.7 & d1.c2uCHP2.7). We also see that for the specified level of penetration, within the three possible micro-CHP technology options, the system chooses the technology with the medium heat-to-power ratio, i.e. micro-CHP with HPR2.7[152].

[150] The CO2 price is given by a linear trajectory starting at the beginning of the time horizon with a price of 20 [$/ton] and finishing with a price of 98.74 [$/ton] at the end of the time period. For the natural gas retail price we use a price of 16.067 [$/MMBtu] at the beginning of the time horizon (refer to Chapter 5 for more details and references).

[151] We need to recall from Chapter 5 that the LT model includes some restrictions to the installed capacity of certain technologies. Specifically, we allowed new capacity of clean technologies after year t5 and only limited up to 200MW per year. Similarly, neither new capacity nor retirement is allowed for nuclear technology. New old coal power plants are not allowed to develop in the model, although pre-existent plants already in place in the electric system are permitted to be part of the energy mix. Recall that the LT model decides the incremental capacity to install every year in an electric system with installed capacity per technology prior to the beginning of the study time.

[152] Recall that in the LT model we only allowed one micro-CHP technology to supply the heat of a particular customer class. The energy heat portfolio for one customer class can only be a mix of one micro-CHP type and conventional heating units for meeting additional heat requirements. The reason for this simplification rests on the fact that a *residential customer class will not have multiple micro-CHP*

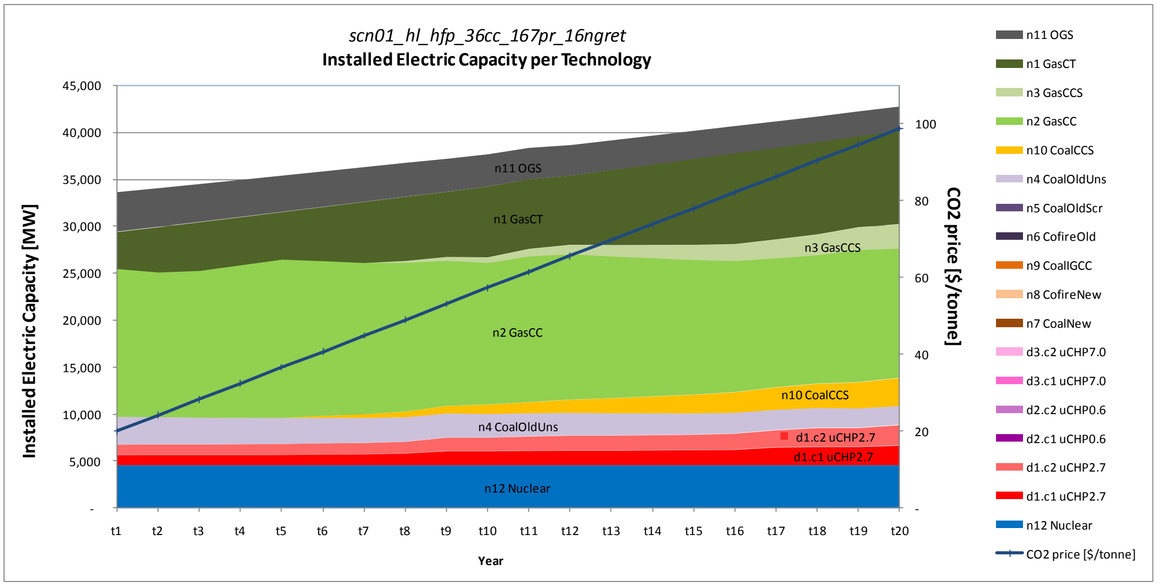

Figure 6.1.1: LT results for the case with micro-CHP - Electric installed capacity [MW] for every year of the time horizon for conventional generating and micro-CHP technologies

Comparing both figures we can clearly see the technologies being used by the system as long-term reserve requirement. Although the penetration of Gas and Fuel Oil turbines in the electric capacity mix is important, their electric production is below 2% (see n1GT & n11OGS in figures). We also notice the drastic electric production change by Old Coal and Gas Combined Cycle technologies (see n4CoalOldUns & n2GasCC in Figure 6.1.2) as a result of the CO2 price above 60 [$/ton] by year t11. The increase of the CO2 price makes cleaner technologies, such as CoalCS and GasCCS, to compete against GasCC and we also see that micro-CHPs are directly competing against GasCC (see n10CoalCCS & n3GasCCS, d1.c1uCHP2.7 & d1.c2uCHP2.7 against n2GasCC in Figure 6.1.2).

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heating devices to supply its heat requirements, and we are *not modeling a district heating system* where the heat can be transferred using pipes.

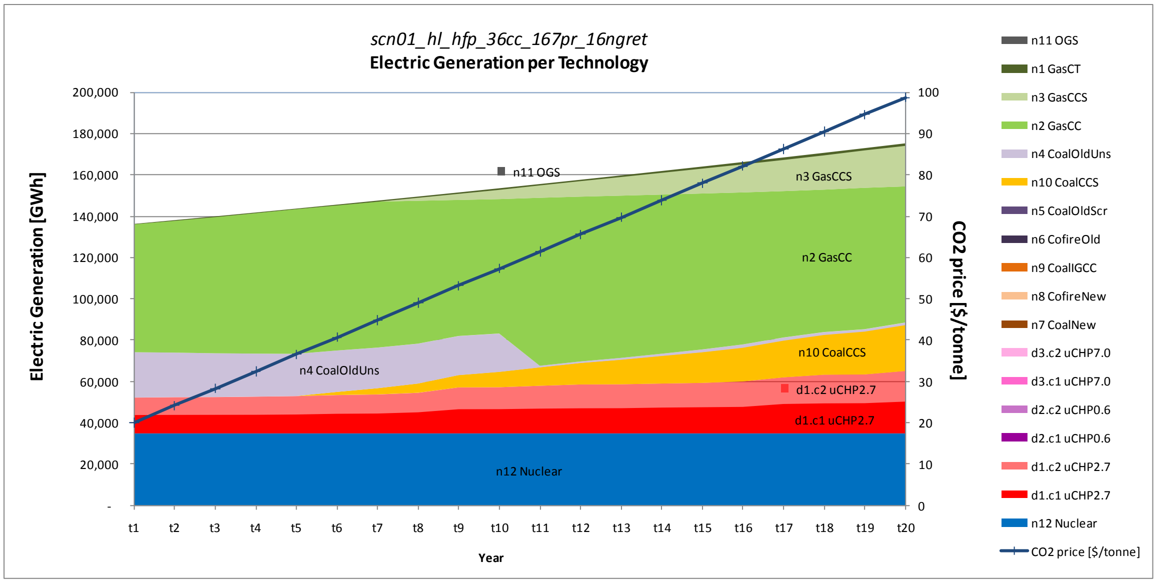


Figure 6.1.2: LT results for the case with micro-CHP - Electric generation [GWh/yr] for every year of the time horizon for conventional generating and micro-CHP technologies

In Table 6.1-1 we showed the numerical results of the LT expansion model for the last year of the time period (i.e. t20 from the above figures).

Year	t20	Installed Capacity [MW]	Capacity mix [%]	Capacity Factor w/o availability[153] [%]	Generation [GWh/yr]	Generation mix [%/yr]
n1	GasCT	9,943	23.2%	1.6%	1,226	0.7%
n2	GasCC	13,804	32.3%	62.5%	65,792	37.5%
n3	GasCCS	2,600	6.1%	100.0%	19,815	11.3%
n4	CoalOldUns	2,000	4.7%	8.1%	1,205	0.7%
n5	CoalOldScr	-	0.0%	0.0%	-	0.0%
n6	CofireOld	-	0.0%	0.0%	-	0.0%
n7	CoalNew	-	0.0%	0.0%	-	0.0%
n8	CofireNew	-	0.0%	0.0%	-	0.0%
n9	CoalIGCC	-	0.0%	0.0%	-	0.0%
n10	CoalCCS	3,000	7.0%	100.0%	22,338	12.7%
n11	OGS	2,580	6.0%	0.0%	0	0.0%
n12	Nuclear	4,500	10.5%	100.0%	34,690	19.8%
d1.c1	uCHP2.7	2,170.5	5.1%	80.3%	15,275	8.7%
d2.c1	uCHP0.6	-	0.0%	0.0%	-	0.0%
d3.c1	uCHP7.0	-	0.0%	0.0%	-	0.0%
d1.c2	uCHP2.7	2,181.4	5.1%	78.8%	15,055	8.6%
d2.c2	uCHP0.6	-	0.0%	0.0%	-	0.0%
d3.c2	uCHP7.0	-	0.0%	0.0%	-	0.0%
Total		**42,779**	**100%**		**175,396**	**100%**

Table 6.1-1: LT model results for the last year (t20) of the time horizon.

From this table we see the results in terms of capacity and production within the electric portfolio of the micro-CHPs. *These numbers will be later used as input for the short-term model to simulate the operation of an energy system for year t20.* We

[153] Capacity factor is calculated before considering the availability per generating technology.

need to clarify that, although we obtained results for the electricity production in year t20, these results will be more accurately estimated using the ST model for an hour-by-hour operation and using chronological energy loads.

Finally, the reference case shown in Figure 6.1.1 and Figure 6.1.2 was compared to the case where micro-CHPs are not allowed to develop as part of the system's energy mix (results are shown in "Appendix C.10. Long-term results for the case with no micro-CHP"). As we mentioned earlier, in Figure 6.1.3 and Figure 6.1.4 we can clearly see that micro-CHP competes against gas-fired technologies, especially Gas Combined Cycle units.

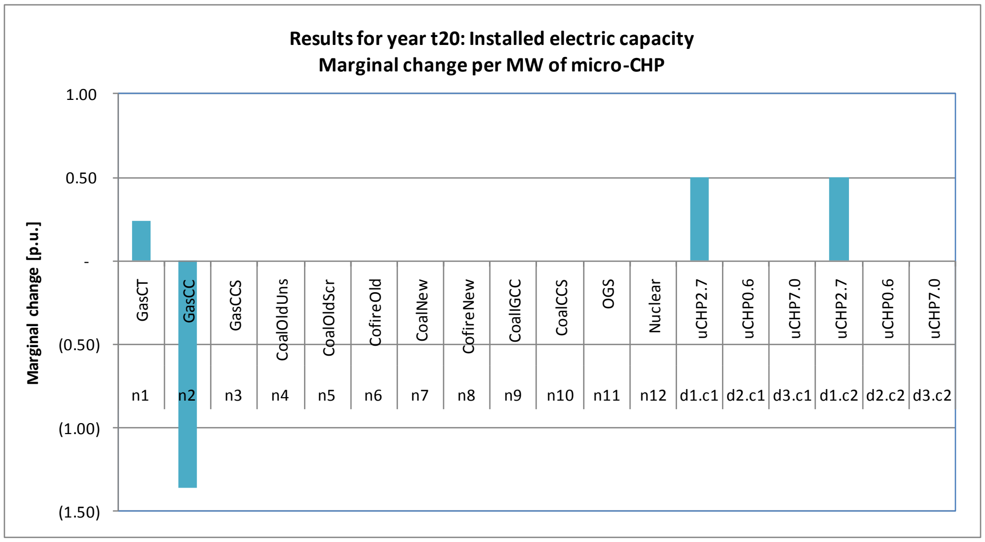


Figure 6.1.3: Comparative results for micro-CHP vs. no micro-CHP cases - Installed capacity marginal change per every installed MW of micro-CHP

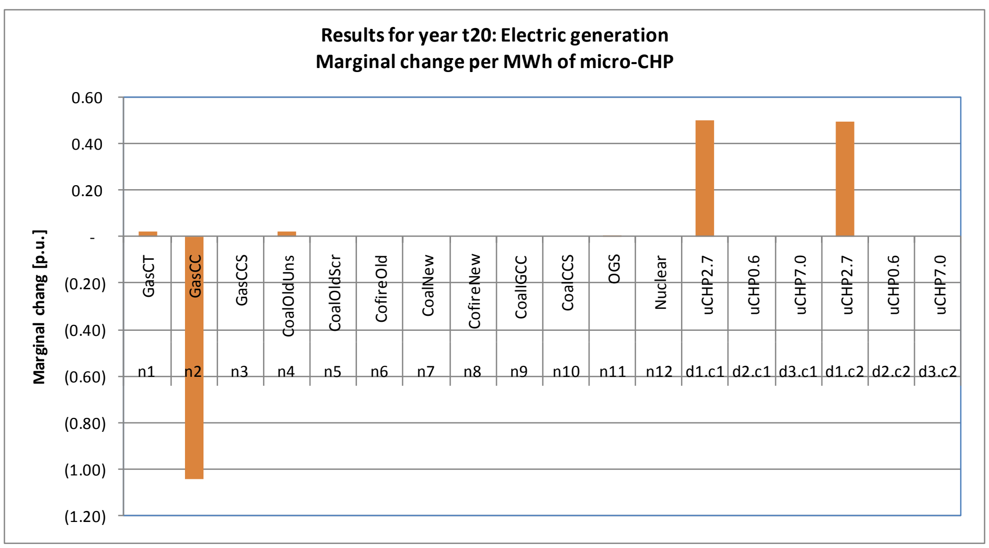


Figure 6.1.4: Comparative results for micro-CHP vs. no micro-CHP cases - Electric production marginal change per every produced MWh of micro-CHP

In terms of CO_2 emissions, when comparing the case of having micro-CHP versus not having micro-CHPs within the energy portfolio, we obtained a decrease of about 4% - for the case of having 10% micro-CHP penetration in a scenario with high CO_2

price and high natural gas retail price. Emissions are estimated for the cumulative 20 years time period, considering emissions coming from the production of electricity and heat in the system (see Figure 6.1.5).

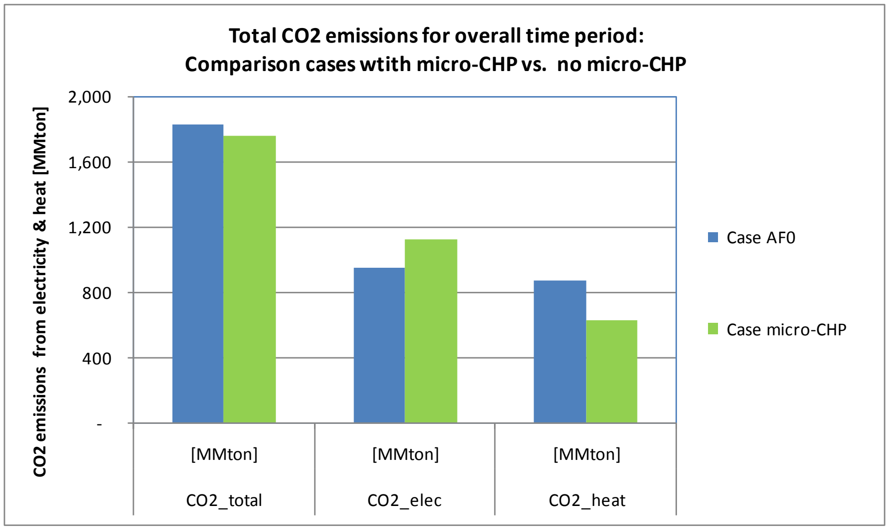


Figure 6.1.5: Comparative results for micro-CHP vs. no micro-CHP cases – Cumulative CO2 emissions for 20 years period

6.1.2. Sensitivity analysis to micro-CHP capital cost

These analyses are performed varying the micro-CHPs capital cost (in $ per kWe) within a range of potential values. Current literature mentions prices [(95),(96), (97), (98), and information provided by manufacturers[154]] that fluctuate between 1,500 [$2007/kWe] and 12,500 [$2007/kWe], with prices differing on the technology being used, the supporting equipment required, the country/region where the micro-CHP is being commercialized, and authors' own estimation of the future price for micro-CHPs. In addition, prices may include the cost of additional equipment such as auxiliary burners for meeting peaking demand (the case of packaged units), while in other cases residential customers are required to purchase these equipments such as buffer tanks or furnaces - depending on the heating system configuration.

[154] This information was provided by direct communication with representatives of Marathon Engine Systems and Climate Energy LLC supplying to the U.S., and Whisper Tech Limited supplying to Europe.

A summary of the costs is shown in the Table 6.1-2 below[155]:

Micro-CHP technology	Electric size range [kWe]	Range in EU [$2007/kWe]	Range in US [$2007/kWe]
Internal combustion engine (ICE)	1.0 - 1.2	7,500 – 9,500	11,200
	4.7 - 5.5	4,000 – 4,800	5,300 – 6,000
Stirling Engine (SE)	0.8 - 1.2	7,500 – 12,500	N/A
	3.0 - 9.5	4,300 – 7,300	N/A
Fuel Cell PEM (FCPEM)	1.0 - 3.0	1,300 – 6,000	N/A
Fuel Cell SO (FCSO)	N/A	N/A	N/A

Table 6.1-2: Summary of micro-CHP prices including CHP unit, auxiliary heating device and installation cost

Recognizing the uncertainty around the capital cost, we performed a sensitivity analysis with prices that go as high as 10,500 [$2007/kWe] and as low as 1,750 [$2007/kWe]. The simulations are done for different CO2 price & natural gas retail price scenarios. In particular:

- Three CO2 price scenarios: i) High price of 98.74 [$/ton], ii) Medium price of 49.4 [$/ton], and iii) No CO2 price. In all cases the price trajectory was assumed to have linear increase starting from 20 [$/ton] until reaching the desired price.
- Three natural gas retail price scenarios: i) High price of 16 [$/MMBtu], ii) Medium price of 12 [$/MMBtu], and low price of 8 [$/MMBtu]. The price is assumed at the beginning of the period with an annual increase of 0.5 % per year.

In this section we will first explain the results obtained for the particular scenario of having high CO2 price & high natural gas retail price (the results for the other cases can be found in Appendix C.2 to C.5). Then, we will finish with more general observations regarding the penetration of micro-CHPs under different conditions.

6.1.2.1. Results of scenario with high CO2 price & high NG retail price.

As mentioned, we adopted a high CO2 price at the end of the time horizon according to (94) for the particular scenario of having emissions reductions to 80% below 2008 emissions by 2050. We assumed an initial price for year t1 of 20[$/ton] and a final price in year t20 of 98.74[$/ton], with a linear increase. We also assumed a retail price for natural gas of 16.067[$/MMBtu] for residential customers in the New England region - according to (93) – with an annual increase of 0.5% per year[156].

[155] The values shown in the table are derived from the values extracted from different sources (see above). These values have been converted to unitary values in $2007 per kWe using the electric capacity of the micro-CHPs noted in these sources, and the following exchange rates and consumer price indexes:

Year	CPI (106)	EXR GBP (107)	EXR EUR (107)
2005	195.30	1.82	1.25
2006	201.60	1.84	1.26
2007	207.34	2.00	1.37
2008	215.30	1.86	1.47
2009	214.54	1.57	1.39

[156] As explained in Chapter 5, we assumed a 0.5[%/yr] increase for all fuel prices.

In Figure 6.1.6 we see that the penetration of micro-CHPs increases when the capital cost decreases. Micro-CHPs are not part of the electric energy portfolio if the capital cost is high; however for values smaller than 6,500[$/kWe] the penetration starts increasing, reaching approximately 35% for a low capital cost of about 1,750[$/kWe]. *For the particular case of having a 10% micro-CHP penetration in the electric energy mix, the value of the technology has to be between 4,500 and 4,200 [$/kWe]*[157].

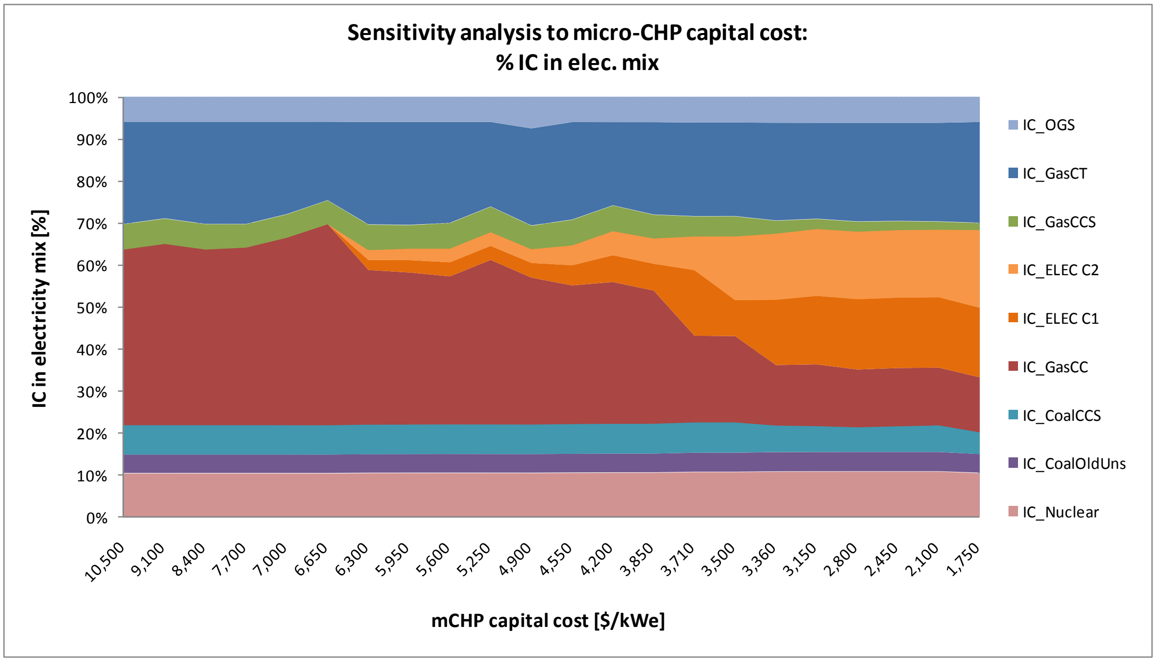


Figure 6.1.6: Percentage of electric installed capacity (IC) within the electric portfolio at the end of the time horizon, per conventional generating and micro-CHP technology (case with High CO2 price/High NG retail price)

From the figure we can see that *micro-CHPs displace installed capacity from gas-based technologies*, particularly gas combined cycle (IC_GasCC) and gas combined cycle with carbon capture & sequestration (IC_GasCCS). The figure shows the penetration of micro-CHP for both classes of customers, being very similar in both cases (see IC_ELEC C1 & IC_ELEC C2).

Focusing at the micro-CHP penetration only, we looked at its effect on the cumulative CO2 emissions over the 20 years of the time of analysis. CO2 emissions are calculated taking into account emissions derived from producing electricity and heat with conventional generating and distributed heating technologies, and micro-CHPs (emissions are estimated for every year and a cumulative number is calculated for the entire time horizon). Figure 6.1.7 shows the cumulative CO2 emissions decrease with respect to the case without micro-CHP (see Eth_change). Here we see that for a *10% micro-CHP electric installed capacity, emission reductions are close to 4.0%, while for a 30% penetration emission reductions are around 10%*.

[157] This price does not include the cost of an auxiliary heating device for meeting peak heat demand.

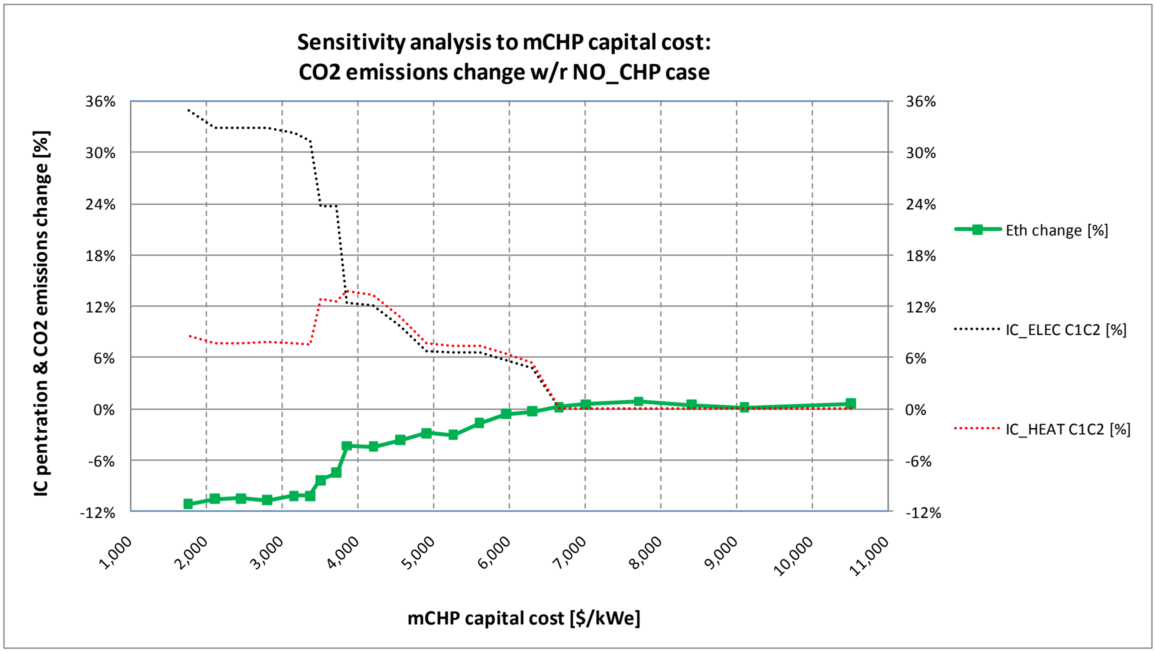


Figure 6.1.7: Micro-CHP penetration and its effect on CO2 emissions (case with High CO2 price/High NG retail price)

Figure 6.1.7 also shows the total penetration of micro-CHP as a % of the total installed electric and heat capacity within the electric & heat energy portfolios (see IC_ELEC C1C2 & IC_HEAT C1C2)[158]. We see that as the electric penetration gets higher - around 20% - the heat penetration suddenly diminishes from around 13% to 8% of the heat installed capacity. As we will see in the figures below, this is because the *system changes micro-CHP technology; so instead of choosing a technology with a HPR of 2.7, the system prefers a technology with the lowest HPR of 0.6 which is able to produce much less heat per unit of electricity*.

We need to recall that the long-term expansion model does not allow a mix of micro-CHP technologies to meet the heat demand of each customer class. Thus, the model can choose auxiliary heating systems and/or one micro-CHP technology only to meet heat load.

From Figure 6.1.8 and Figure 6.1.9 we note that *as the micro-CHP electric penetration increases, the type of technology preferred by the system changes to the one that produces less heat per every unit of electricity* (see IC_CHP27 & IC_CHP06 for customer class C1 and C2). For each class of customer, when the electric penetration is close to 10%, the system shifts technology from HPR2.7 to a micro-CHP with HPR0.6. Clearly we see from these figures that, when the system changes to a micro-CHP technology with HPR0.6, the penetration within the heat portfolio decreases substantially as the production of heat is much less with this new technology (see IC_HEAT for customer class C1 and C2). As we will explain later, *it seems that as the cost of micro-CHP goes down, this technology becomes competitive in electricity production. Therefore heat production becomes a clearly secondary activity.*

[158] The total penetration considers the sum of the installed capacity for both classes of customers.

In addition, looking at Figure 6.1.8 and Figure 6.1.9 we note that, *from the system's point of view, the technology with the highest HPR of 7.0 is never chosen*. There are two reasons behind this:

- Micro-CHP heat production per unit of electricity of is too high for the heat demand being modeled for each customer class.
- Micro-CHP costs of producing heat - after considering the savings for electricity - are more expensive for this type of technology than for technologies with lower heat-to-power ratio (we explain this in detail at the end of this section).

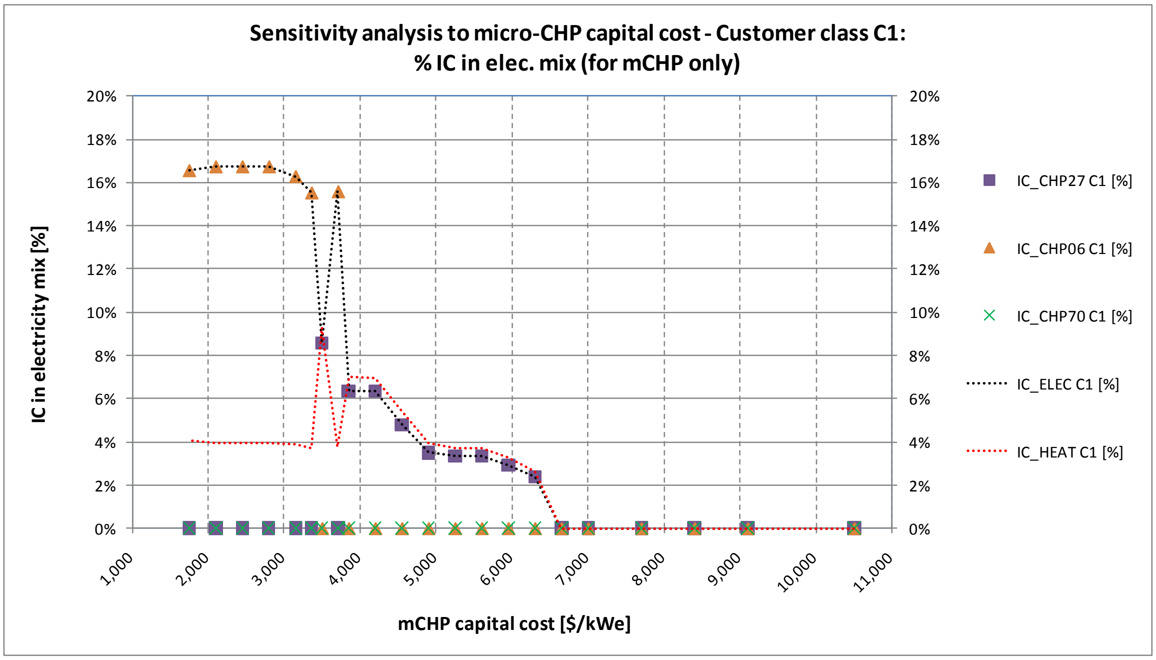


Figure 6.1.8: Micro-CHP penetration per technology for C1 (case with High CO2 price/High NG retail price)

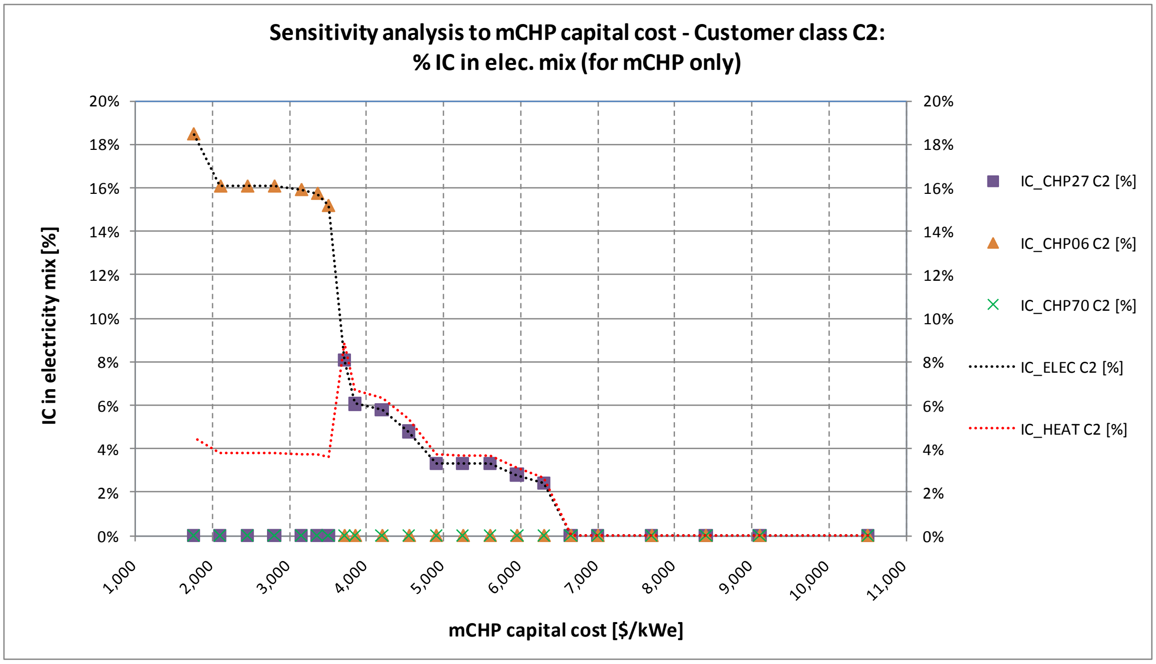


Figure 6.1.9: Micro-CHP penetration per technology for C2 (case with High CO2 price/High NG retail price)

6.1.2.2. General findings from all scenarios

As we mentioned above, similar analyses on the micro-CHP capital cost sensitivity were performed for scenarios with medium and no CO2 price, and medium and low natural gas retail price (see Appendix C.2 through C.5). In Table 6.1-3 we summarized these results, where we *focus on the case of having 10% micro-CHP penetration within the electric capacity portfolio*:

Results for 10% micro-CHP	**Note**	**High NG retail price**	**Medium NG retail price**	**Low NG retail price**
High CO2 price	(1)	~ 4,500 [$/kWe]	~ 5,800 [$/kWe]	~ 8,000 [$/kWe]
	(2)	~ 4.0 [%]	~3 - 5.5 [%]	~ 2.7 - 5.2 [%]
	(3)	GasCC, some GasCCS & CoalCCS	GasCC, some GasCCS & CoalCCS	GasCC, some GasCCS & CoalCCS
Medium CO2 price	(1)	~ 4,000 [$/kWe]	~ 5,400 [$/kWe]	~ 7,300 [$/kWe]
	(2)	~ 4.0 [%]	~ 3.3 - 6.4 [%]	~ 2.9 - 5.7 [%]
	(3)	GasCC, some GasCT	GasCC, some GasCT	GasCC, some GasCT
No CO2 price	(1)	~ 3,000 [$/kWe]	~ 4,000[$/kWe]	~ 5,800 [$/kWe]
	(2)	~ 6.4 - 11.5 [%]	~ 8.7 - 16.3 [%]	~ 9 - 19 [%]
	(3)	Coal & GasCC, some GasCT	Coal & GasCC	Coal & GasCC

Table 6.1-3: Summary of sensitivity analyses to micro-CHP capital cost for varied CO2 price & natural gas price conditions.

Where:

(1) Micro-CHP capital cost for a 10% electric installed capacity [$/kWe],

(2) CO2 emissions reduction for a 10% electric penetration with respect the case without micro-CHP [%], and

(3) Displaced technologies as the micro-CHP penetration increases.

The sensitivity analyses on the micro-CHP capital cost showed that:

a. *Lower micro-CHP capital cost increases the penetration of micro-CHPs, and favors the deployment of low heat-to-power ratio micro-CHPs.* For high capital costs, micro-CHP is not a competitive technology (i.e. it is not part of the system energy portfolio) and the system prefers conventional heating units for supplying heat requirements. For medium capital costs, the heat portfolio considers micro-CHPs with HPR2.7 as an option in addition to the conventional heating units. Finally for low capital costs, micro-CHPs with low HPR0.6 is the preferred technology combined with conventional heating units for supplying heat loads.

b. *Micro-CHP technology with high HPR7.0 is not a competitive technology when compared to the other available technologies of lower HPR.*

c. *As lower capital cost increases the penetration of micro-CHPs, CO2 emissions are also reduced, with major contributions in a scenario with low CO2 prices.* In particular, a 10% micro-CHP penetration results in between 4%-5% cumulative CO2 emissions reduction within an electricity portfolio dominated by Gas & CCS technologies (mostly high CO2 price scenarios). In a scenario with very low (or non-existent) CO2 price, a 10% micro-CHP penetration represents between 10%-15% emissions reductions.

As the capital cost decreases, we noted that there is competition among micro-CHP technologies to meet the energy requirements. First, there is a technology shift from HPR2.7 to HPR0.6. Second, the system does not choose the technology with HPR7.0 as an energy alternative. For understand this effect, we looked at the levelized cost of heat to estimate the total cost of producing heat with the different technologies, while also considering the savings from producing electricity (see "Appendix C.1. Levelized heat cost after savings with micro-CHPs & conventional heating technologies" for details). A graphic representation of the levelized costs of heat (after savings) allows us to see how the technology of choice changes as the capital cost:

- As the *fixed cost decreases to low values*, the variable cost component dominates the cost structure. Thus, for small capital cost values the technology with the cheapest variable cost (after savings) is preferred. Thus, the levelized cost of producing heat considering these savings is cheaper for micro-CHP with HPR0.6 as seen in Figure 6.1.10 (see mCHP0.6).

- As the *fixed cost increases to a medium value*, we note that the micro-CHPs along with conventional heating technologies compete among them to be part of the heat energy portfolio. In Figure 6.1.10 we see that under some cost reduction (between 35% and 55%), the low HPR micro-CHP becomes expensive and the medium HPR micro-CHPs is the one with the lowest heat cost (see mCHP0.6 & mCHP2.7).

- Finally, in the case where the *micro-CHP capital cost is high*, *the boiler is the technology of choice to meet heat demand*. As the micro-CHP fixed cost increases, the boiler becomes very competitive and on-site production of electricity is not cost-effective for residential customers (see Boiler in Figure 6.1.10).

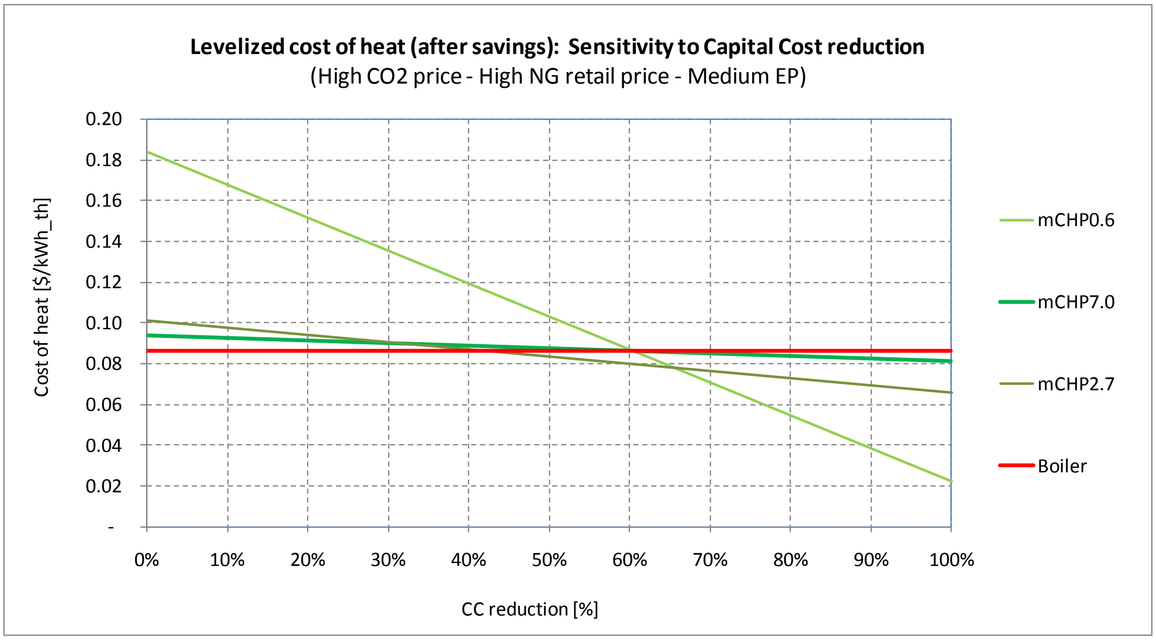


Figure 6.1.10: Approximate Levelized Cost of heat (after savings) for residential heating technologies - Sensitivity to capital cost

6.1.3. Sensitivity analysis to natural gas retail price

From the earlier results, we noted that the penetration of micro-CHPs is also sensitive to the natural gas retail price paid by residential customers. Thus, in this section we performed sensitivity analysis to natural gas prices varying between 16[$/MMBtu] & 8[$/MMBtu], for different CO2 price and capital cost scenarios:

- Three CO2 price scenarios: i) High price of 98.74 [$/ton], ii) Medium price of 49.4 [$/ton], and iii) No CO2 price. In all cases the price trajectory was assumed to have linear increase starting from 20 [$/ton] until reaching the desired price.
- Two micro-CHP capital cost scenarios: i) High values of 7,000 [$/kWe], and ii) Low value of 3,500 [$/kWe].

First, we will explain the results for the particular scenario of having high CO2 price & high micro-CHP capital costs, to finish with a more general observation regarding the different cases (see Appendix C.6 through Appendix C.9 for full set of results).

6.1.3.1. Results of scenario with high CO2 price & high micro-CHP capital cost

In Figure 6.1.11 we see that micro-CHPs are not part of the energy portfolio when the NG retail price is high. However, their penetration increases when the price decreases. In particular, when the *price is around 9.7 [$/MMBtu] their penetration is* *close to 10%.* In addition we note that micro-CHPs displace installed capacity mostly from Gas Combined Cycles (IC_GasCC).

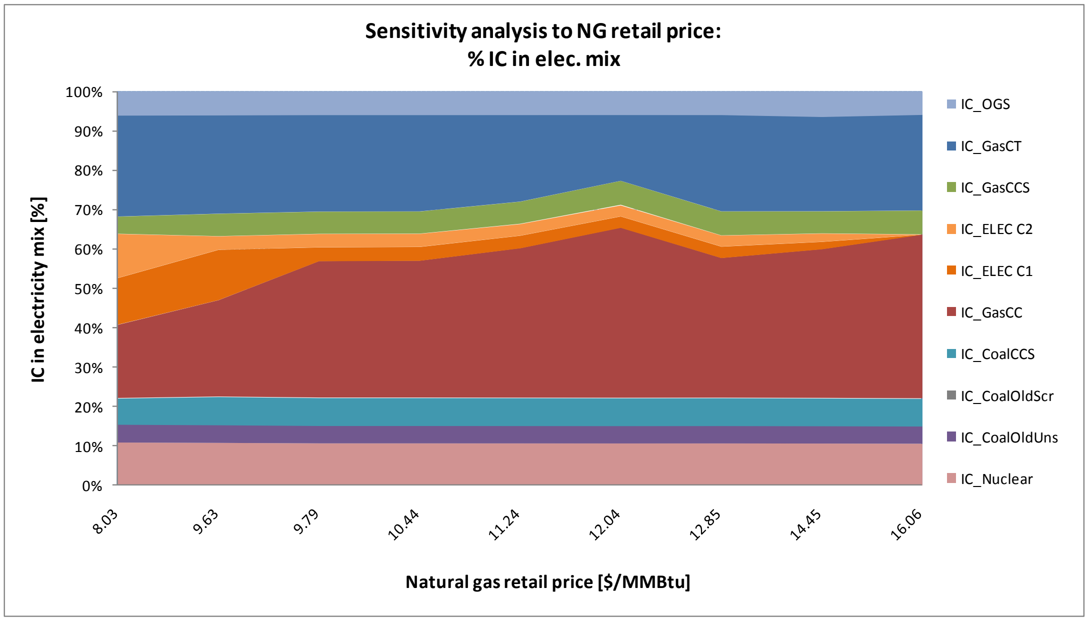


Figure 6.1.11: Percentage of electric installed capacity (IC) within the electric portfolio at the end of the time horizon, per conventional generating and micro-CHP technology (case with High CO2 price/High micro-CHP capital cost).

Then, we looked at the micro-CHP penetration effect on the cumulative CO2 emissions over the 20 years period under analysis. Figure 6.1.12 shows the emissions decrease with respect to the case with no micro-CHP (see Eth_change). For a *10% micro-CHP electric installed capacity, the emission reductions are around 4%*.

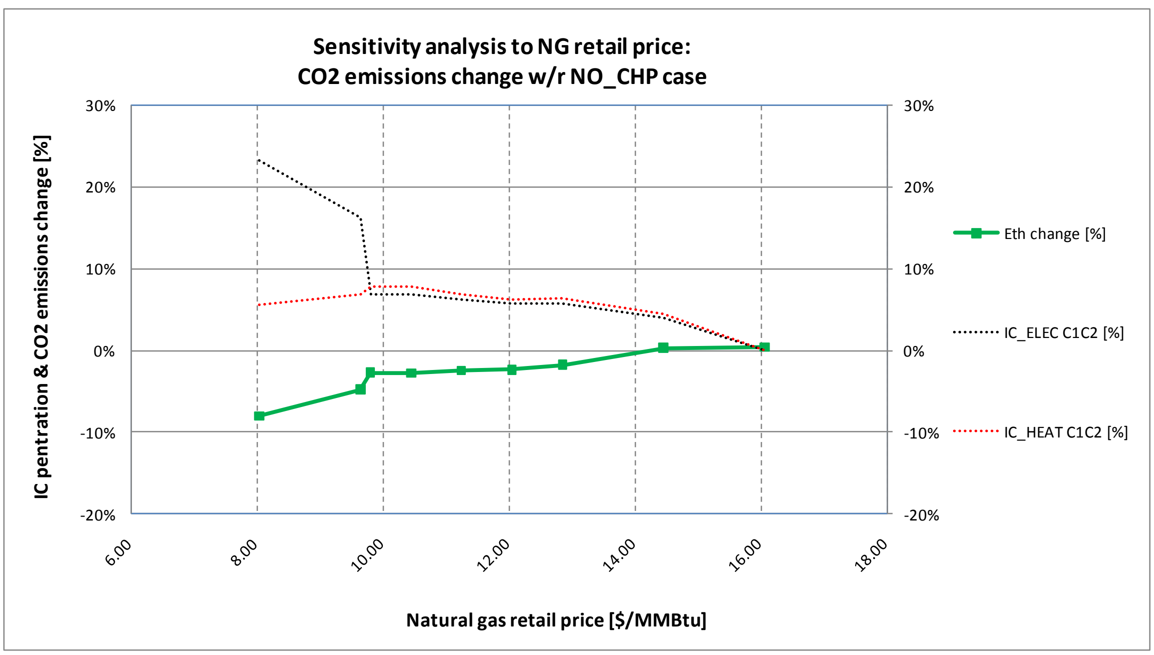


Figure 6.1.12: Micro-CHP penetration and its effect on CO2 emissions (case with High CO2 price/High micro-CHP capital cost).

From Figure 6.1.12 we see that when electric penetration gets high – beyond 10% - the heat penetration does not increase. As we have seen before, the energy system changes micro-CHP technology from a technology with a HPR2.7 to a technology with the lower HPR0.6 (able to produce less heat per unit of electricity). Figure 6.1.13 and Figure 6.1.4 show these results more clearly for each customer class being modeled (see IC_CHP27 & IC_CHP06 for customer class C1 and C2). In both cases, when the natural gas retail price is less than 10 [$/MMBtu] and the electric penetration greater than 5%, the system shifts technology.

Similar to what we noted for the capital cost sensitivity analysis, the technology with the highest HPR7.0 is never chosen as part of the energy heat portfolio. To explain this effect, at the end of this section we analyze the heat production cost of the different technologies as a function of natural gas retail price.

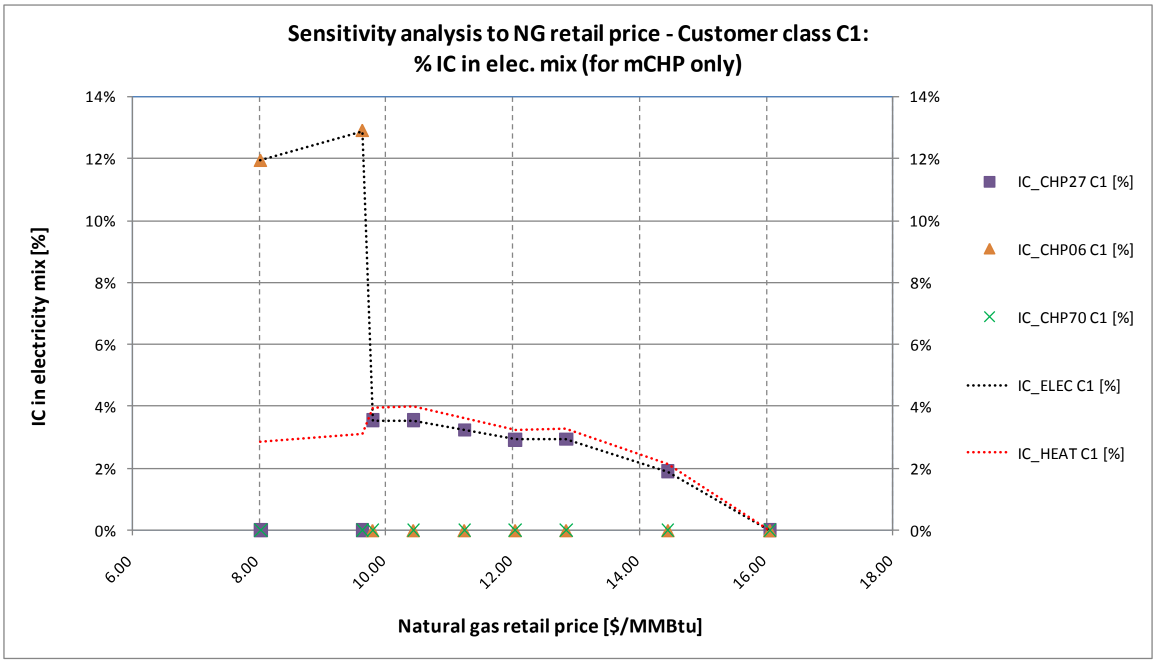


Figure 6.1.13: Micro-CHP penetration per technology for customer class C1 (case with High CO2 price/High micro-CHP capital cost)

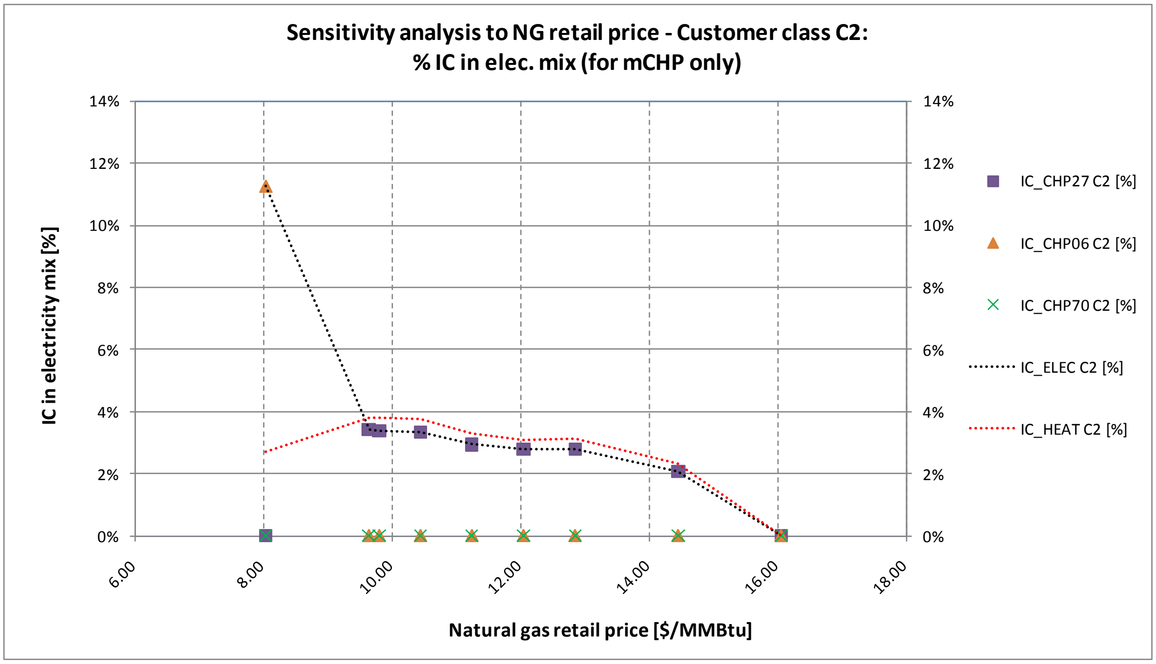


Figure 6.1.14: Micro-CHP penetration per technology for customer class C2 (case with High CO2 price/High micro-CHP capital cost)

6.1.3.2. *General findings from all scenarios*

Similar analyses on the NG retail price sensitivity were performed for scenarios with medium and no CO2 price, and high and medium capital cost (see Appendix C.6 through Appendix C.9). In Table 6.1-4 we summarized these results, where we focus on those cases where micro-CHP penetration is close to 10% within the electric capacity portfolio. We need to note that in some cases it is not possible to have 10% penetration. Therefore, for those cases we show the results for other levels of penetrations denoted with (*).

Results for some % micro-CHP	Note	High micro-CHP capital cost	Medium micro-CHP capital cost
High CO2 price	(1) (2) (3)	~ 9.7 [$/MMBtu] for about 10% penetration ~ 3.8 [%] for about 10% penetration GasCC, some GasCCS	~ 16 [$/MMBtu] for about 24% penetration (*) ~8 [%] for about 24% penetration (*) GasCC, some GasCCS & CoalCCS
Medium CO2 price	(1) (2) (3)	~ 8.6 [$/MMBtu] for about 10% penetration ~ 6 [%]for about 10% penetration GasCC & GasCT, some Fuel oil	~ 16 [$/MMBtu] for about 15% penetration (*) ~ 5.5 [%]for about 15% penetration (*) GasCC & GasCT, some Fuel oil
No CO2 price	(1) (2) (3)	~ 8 [$/MMBtu] for less than 2% penetration (*) ~ 2 [%] for less than 2% penetration (*) Coal & GasCC	~ 13.5 [$/MMBtu] for about 10% penetration ~ 9 [%]for about 10% penetration Coal & GasCC

Table 6.1-4: Summary of sensitivity analyses to NG retail price for varied CO2 price & micro-CHP capital cost conditions.

Where:

(1) Natural gas retail price in year t0 for the specific % of electric installed capacity [$/MMBtu],

(2) CO2 emissions reduction for the specific level of electric penetration with respect the case without micro-CHP [%], and

(3) Displaced technologies as the micro-CHP penetration increases.

The sensitivity analyses on the NG retail price showed that:

a. *Lower NG retail price for residential customers increases the penetration of micro-CHPs and favors the deployment of low heat-to-power ratio micro-CHPs.* For high NG retail prices, micro-CHP is not a competitive technology and the system prefers conventional heating units for supplying heat requirements (although if the capital cost decreases, micro-CHPs could become competitive under high fuel price conditions). As the NG retail price decreases, micro-CHPs increase their penetration within the energy portfolio (even for high capital cost values). For medium NG retail prices, the heat portfolio considers micro-CHPs with HPR2.7 as an option in addition to the conventional heating units (if the capital cost decreases, then the preferred technology shifts to the one with the lowest heat-to-power ratio). Finally, for low NG retail prices, we see that micro-CHPs with low HPR0.6 is the technology of choice along with conventional heating units for supplying heat demand (this trend is seen regardless of the capital cost value).

b. *The penetration level of micro-CHPs is given by the relationship between the NG retail price and the technology capital cost.* Thus the same level of penetration could be achieved with different combinations of price and capital cost reduction. For example, a 10% penetration could be achieved either having a low NG retail price close to 9.5$/MMBtu and a high capital cost of 7,000$/kWe, or a medium NG retail price of about 13.5$/MMBtu and a low capital cost of 3,500$/kWe.

c. *Micro-CHP technology with high HPR7.0 is not a competitive technology (compared to the other available technologies with lower HPR) when subjected to varying NG retail prices.*

d. *As lower natural gas retail price increases the penetration of micro-CHPs, CO2 emissions are also reduced. The major benefits are achieved in a scenario with low CO2 prices.*

As the NG retail price decreases, we noted that the system prefers micro-CHPs with low HPR to meet energy requirements. Again, similar to what we did previously, we looked at the heat cost structure - after savings for producing electricity - of the different micro-CHP technologies, and we observe the same results shown by the LT model (see Figure 6.1.15):

- As the *retail natural gas price decreases*, the cost of produce heat substantially drops for micro-CHPs with low HPR (see mCHP0.6 in figure).
- As the *retail natural gas price increases to medium values*, the levelized cost of heat increases for all the technologies and the micro-CHP HPR2.7 is the technology with the lowest production cost (see mCHP2.7 in figure).
- Finally, in the case where the *retail natural gas price is high*, *the boiler is the technology of choice to meet heat demand*. In Figure 6.1.15 we see that while the micro-CHP with HPR7.0 has a similar cost to the boiler, as its capital cost is larger this technology is left out of the energy heat portfolio (see mCHP7.0 and Boiler in the figure).

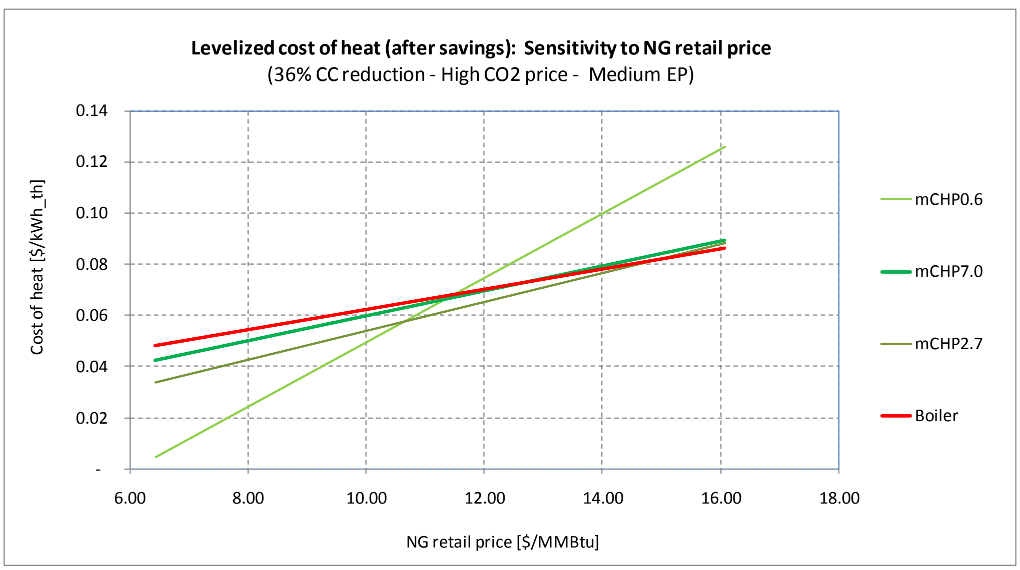


Figure 6.1.15: Approximate Levelized Cost of heat (after savings) for residential heating technologies - Sensitivity to NG retail price

6.1.4. Micro-CHP sensitivity to CO2 price

Finally, we look at how varying CO2 prices impact the development of micro-CHPs. For this purpose we used the same sensitivity analyses for capital cost and natural gas retail price, and we analyzed the results for the different CO2 price scenarios (see Appendix C.2 through Appendix C.9). We observed the following:

a. *Higher CO2 price favors the development of micro-CHPs.* For high CO2 price, new conventional coal plants do not develop within the electric portfolio and the mix is dominated by gas-fired technologies with some clean technologies. As the CO2 price gets lower, there is no development of clean generating technology such as Gas & Coal CCS technologies, and the electric portfolio dominated by conventional gas power plants and cheap conventional coal power plants in the case without CO2 price. Under these circumstances, the penetration of micro-CHP displaces mostly gas under high CO2 prices, and coal-fired units under low CO2 prices. In the later case, as the electric costs are cheaper - because of low CO2 prices - it is more difficult for micro-CHPs to compete in the electric system.

b. *The effect of CO2 price on the technology choice is more complex, as the price not only affects the cost of the heating technology, but also the electric energy mix and hence the electricity prices used to value the savings because of the simultaneous electricity production.* If the CO2 price is included within the variable cost of the electric power plants, then an increase of CO2 price should result in a more expensive electric system (see "Appendix C.11. Electric variable costs for conventional & micro-CHP technologies for year 20"). Therefore, the price to value the savings related to the electricity produced by micro-CHPs should also increase. In particular, the micro-CHP with HPR0.6 is the technology that brings the largest savings. If the electricity price is high, then the electricity savings can be very significant, to the point to make this technology the most convenient even under high CO2 prices. According to this, *it seems that higher prices favor the micro-CHP technology with the lowest HPR. However further research is required in this area to state this.*

c. *Similar to the previous analyses, micro-CHP technology with high HPR7.0 is not a competitive technology (compared to the other available technologies of lower HPR) when subjected to varied CO2 prices.*

d. For the same level of penetration*, higher CO2 price decreases the contribution to CO2 emissions reduction by micro-CHPs.* As the CO2 price decreases we observe that the electric energy mix does not include clean technologies, so micro-CHPs compete mostly against gas-fired technologies and coal technologies. Thus, for a 10% micro-CHP penetration level, emissions reductions will be greater for the scenario with No CO2 price compared to the case with higher CO2 price as the micro-CHP is also displacing coal-fired technologies.

6.1.5. Micro-CHP sensitivity to electricity price

In order to explain the results from the LT model, we have used for illustration purposes the notion of levelized heat cost of the heating technologies that takes into account the potential micro-CHP savings from producing electricity[159]. Based on this analysis, we noted that the price to value these savings has a key role on the final cost of heat of the micro-CHP technologies.

The technology with the lowest HPR is the one with the biggest electricity savings. For example, a micro-CHP with HPR0.6 produces 0.6kWth of heat per 1kWe of electricity or, equivalently, 1.67kWe per 1kWth. Thus, savings are included in the calculations of levelized cost of heat as:

$$Electricity\ savings\ [\$] = -\frac{1}{HPR}\left[\frac{kWh\_e}{kWh\_th}\right] \times Q_{th}^{chp}[kWh\_th] \times Price_{electricity}\ [\frac{\$}{kWh\_e}]$$

From this expression we can see that the higher the electricity price, the higher the savings are, in particular for the technology with the lowest HPR. In Figure 6.1.16 and Figure 6.1.17 we show the effect of the electricity price value on the levelized heat costs (after savings). If savings were not taking into account, clearly the cost of heat is more expensive for micro-CHP HPR0.6 (Figure 6.1.16). However, for a medium electric price (0.140$/kWhe for instance) the savings are about 233$/kWhth per units of produced heat - constant for all the NG retail price range - making the micro-CHP with HPR0.6 cheaper than other technologies for low NG gas retail prices (Figure 6.1.17).

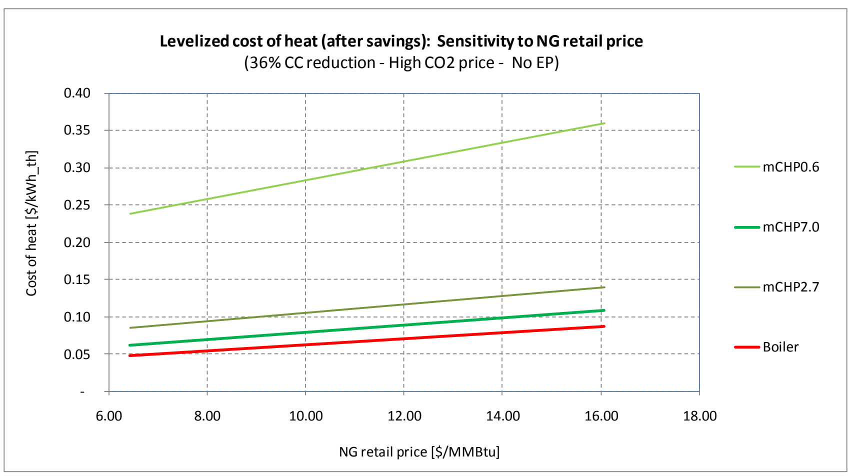


Figure 6.1.16: Levelized Cost of heat (after savings) - Sensitivity to NG retail price with NO electricity price (EP)

[159] There is the challenge in determining the total cost of producing heat with micro-CHP units, as the economic effect of simultaneously producing electricity has to be included within the calculations. In the long-term expansion model, we do not have this problem as both electricity and heat demand are explicitly included in the simulations.

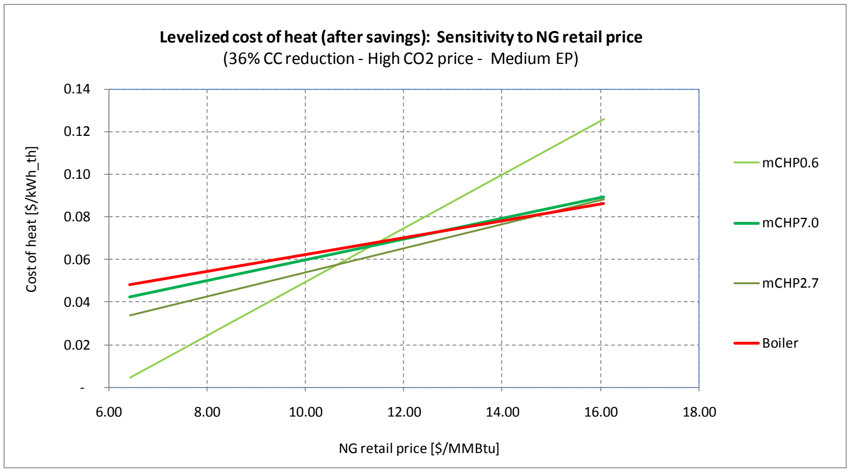


Figure 6.1.17: Levelized Cost of heat (after savings) - Sensitivity to NG retail price with medium electricity price (EP)

More generally, in Figure 6.1.18 we illustrate the effect of electricity price on the cost of heat (after savings) for the different residential heating technologies. The cost order changes depending on whether the price is low or high, which impacts the technology adoption decision observed in the LT model. From the figure we note that:

- Micro-CHP with HPR7.0 is always more expensive than the other technologies. Therefore, it is not part of the heat energy mix as it has been shown by the different results of the LT expansion model throughout this chapter (mCHP7.0 in figure).
- For high electricity prices, micro-CHP HPR0.6 is the one that has the lowest levelized heat cost after savings. This micro-CHP can generate more electricity per unit of heat, so the associated savings because of the generated electricity are substantial compared to the other technologies. This is reflected in a decrease of the cost of heat up to a level lower than the cost of the other technologies.
- For medium electricity prices, we observe that the micro-CHP with HPR2.7 is the one with the cheapest costs. Although electric savings are much smaller than the technology with high HPR, the cost of producing heat-only are low enough to make this technology a better choice than the micro-CHP HPR0.6.
- For low electricity prices, clearly the production of electricity is not cost-effective for residential customers as its potential economic benefits are low. Customers favor the use of conventional heating technologies, i.e. boiler, to produce heat (see Boiler in figure) as the cost to generate only heat is much lower for these technologies.

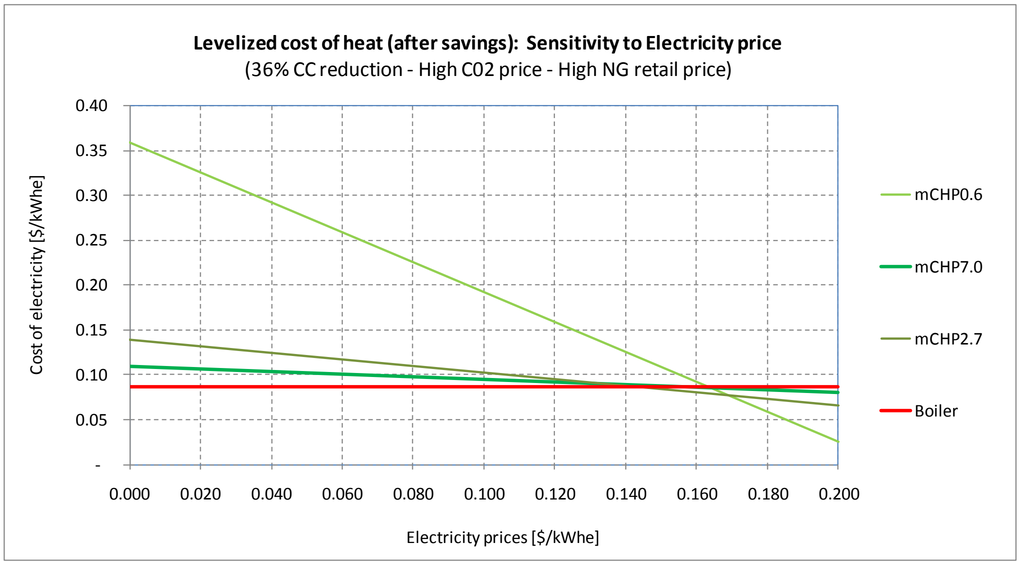


Figure 6.1.18: Heat cost considering electricity savings – Sensitivity to electricity price

Finally, only if the electricity price is significant enough, we are able to observe the sensitivity of micro-CHP to varying capital cost values, NG retail prices and CO2 prices using the notion of levelized cost of heat (after savings) [160]. As the long-term expansion model explicitly includes both electricity and heat in the residential demand equations, the valuation of the electricity savings is already incorporated within the simulations[161].

6.1.6. Summary

This section focused on understanding the long-term impacts of having a widespread penetration of micro-CHPs within an energy system. Using a generation capacity expansion model, we simulated the evolution of an energy (electric & heat) portfolio with an increasing number of micro-CHPs over a 20 years period.

First, we focused on the particular case of having 10% micro-CHP electric penetration at the end of the time horizon. We identified the conditions for having that level of penetration, the technologies chosen by the system to supply energy, and the cumulative CO2 emissions from producing heat and electricity over the time horizon. Thus, in a scenario with high carbon price, we observed that:

- The value of the micro-CHP technology could be either close to 4,500[$/kWe] if the NG retail price were high, or as high as 8,000[$/kWe] if the NG retail price were low.
- The technologies chosen to supply heat are conventional heating units and micro-CHP units with medium heat-to-power ratio, for both classes of customers.

[160] If we take a low value for electricity price, we are not able to see any of the variations of micro-CHP to capital cost and natural gas retail prices.
[161] For the showed results where we use the levelized cost of heat (after savings), we took an electricity price of 0.140$/kWhe. From the LT model, we looked at the Lagrange multiplier of the electricity demand constraint which was close to the value we assumed for the levelized cost calculations.

- Cumulative CO2 emissions reductions are between 4%-5% with respect to the case without micro-CHP for the 20 years period.

Second, we looked at the micro-CHP's penetration to varied investment cost, natural gas retail price and carbon price conditions. We identified the economic conditions that favor the penetration of micro-CHPs, as well as the technologies being displaced by micro-CHPs. Results showed that:

- Lower micro-CHP capital cost increases the penetration of micro-CHPs. If the capital cost is high, micro-CHPs are not a competitive and they are not part of the energy portfolio. The system prefers conventional heating units for supplying heat requirements.
- Similarly, lower natural gas retail price for residential customers increases the penetration of micro-CHPs. For high NG retail prices, micro-CHP is not competitive compared to the other heating technologies.
- It seems that higher CO2 price favors the development of micro-CHPs, although further research is required.
- Micro-CHPs displace installed capacity from gas-based technologies. Particularly, when the carbon price has high to medium values, micro-CHPs displace mostly natural gas combined cycle units.

Third, we observed that conventional heating and micro-CHP technologies compete to supply the residential heat demands under varied market conditions. Results showed that:

- As the costs of micro-CHPs decrease - either through less investment costs or cheaper retail fuel prices – the energy system shifts technology from one with medium HPR2.7 to one with low HPR0.6 In fact, either low micro-CHP capital costs or low NG retail prices for residential customers clearly favor the deployment of micro-CHPs with low heat-to-power ratio, which is able to produce more electricity per units of heat.
- As the costs of micro-CHPs increase, the boiler becomes more competitive and on-site production of electricity is not cost-effective for residential customers. Thus, the energy system does not choose the technology with high HPR7.0 as an energy alternative[162].

Finally, we looked at the role of electricity prices on the micro-CHP's cost of heat, considering the savings for simultaneously producing electricity[163]. We observed that:

- For high electricity prices, the potential economic savings can be high, in particular for micro-CHPs with low HPR. As these micro-CHPs can generate more electricity per units of heat, the savings associated to the production of electricity are substantial compared to other technologies. If the capital costs or NG retail

[162] Micro-CHPs with very high HPR have little savings associated to the production of electricity per units of heat. Thus, the cost of producing heat (after savings) is more expensive for this technology than the other micro-CHPs. Furthermore, the cost of producing heat-only is more expensive than conventional heating units.

[163] As the long-term expansion model explicitly includes both electricity and heat in the residential demand equations, the valuation of the electricity savings is already incorporated within the simulations.

prices decrease, micro-CHPs with HPR0.6 become the technology with the lowest cost of heat (after savings).

- For low electricity prices, the potential economic benefits are low for all micro-CHP technologies. The production of electricity becomes expensive for residential customers, who now favor the use of conventional heating technologies to produce heat. The cost of heat-only is much lower for this type of technologies.

6.2. Results from the Short-Term Operational Model

As noted in Chapter 5, in the short-term operation realm, the electric power system is characterized by an energy portfolio derived from the long-term decision making process, where the system has been adapting throughout the years to increasing levels of micro-CHPs. While keeping the generating capacity fixed for the last year of the time horizon, conventional power plants along with micro-CHPs are allowed to operate efficiently to meet the system electric demand and the heat requirements for the fraction of householders being analyzed. By means of the short-term operational model, we are interested in understanding:

- The systems' electric production with a large number of micro-CHPs, particularly in terms of the type of generation being displaced, and their contribution to electric load reduction during peak times in particular during summer.

- The system's CO2 emissions, considering emissions originated from conventional electric power plants, conventional heating systems and micro-CHPs used for producing electricity and heat.

- The system's total energy efficiency, considering the useful electricity and heat provided by conventional technologies and micro-CHPs and the total fuel used by the system.

- The system's operational costs, as well as the energy costs at residential level in a scenario with an important micro-CHP penetration.

- Finally, the value of micro-CHP technologies to a particular energy system under different economic signals sent to final residential customers. In particular we are interested in analyzing varied electricity retail pricing such as flat, time-of-use and hourly rate designs.

For answering these questions, the short-term operational model is run on an hourly basis for one week of every month of year t20, for the case of no having micro-CHP as an energy alternative and the case of having 10% micro-CHP penetration. Using metrics such as CO2 emissions, efficiency, system's operational costs and residential energy costs, both cases are compared under different retail price schemes. Then, the same metrics are used for understanding the micro-CHP response to price signals with the variation that the analysis is focused on cases with large numbers of micro-CHPs under different electricity rate designs.

6.2.1. System-wide and household metrics

Several metrics at the system & residential levels were calculated to help us understand the impact of micro-CHPs when compared to the case with no micro-CHP units:

1. Annual system's CO2 emissions[164]:

Annual CO2 emissions are estimated considering emissions derived from fuel used by electric power plants, micro-CHPs, and conventional heating units. The expression used for calculating system's CO2 emissions is given by:

$$\begin{aligned} CO2^{system}\ [ton/yr] = & \sum_{h,g} Q_{h,g}^{elec} \cdot ef_g \cdot hr_g^{elec} \\ & + \sum_{h,dms,c} Q_{h,dms,c}^{elec} \cdot ef_{dms,c} \cdot hr_{dms,c}^{elec} \\ & + \sum_{h,aux,c} Q_{h,aux,c}^{heat} \cdot ef_{aux,c} \cdot hr_{aux,c}^{heat} \end{aligned}$$

2. Annual system's energy efficiency[165]:

Annual energy efficiency is estimated as the ratio of useful energy produced by electric power plants, micro-CHPs and conventional heating units to total fuel used in the energy system to supply heat and electricity. The expression used for calculating system's efficiency is given by:

$$Efficiency^{\ system}\ [\%/yr] = \frac{\left(\sum_{h,g} Q_{h,g}^{elec} + \sum_{h,dms,c} \left(Q_{h,dms,c}^{elec} + Q_{h,dms,c}^{heat} - Q_{h,dms,c}^{heat\_waste} \right) + \sum_{h,aux,c} Q_{h,aux,c}^{heat} \right)}{\left(\sum_{h,g} fuel_{h,g} + \sum_{h,dms,c} fuel_{h,dms,c} + \sum_{h,aux,c} fuel_{h,aux,c} \right)}$$

We note here that the effect of energy network losses on the systems' efficiency is not included in this expression (we did not include a network representation in our models).

3. Annual systems' energy production cost:

As explained in detail in Chapter 5, the total production cost (or economic welfare) takes into account producers and consumers' surplus defined as:

[164] We need to mention that in the calculations of CO2 emissions and energy efficiency we are not considering the effect of energy network losses. The short-term model does not include a representation of the electric network, but the economic effect of energy losses has been included as an energy loss factor that increases the variable cost of the conventional electric generation units.
[165] See footnote #164.

- The difference between income and operational costs for conventional electric generators.

- The difference between utility (assumed constant) and electricity costs (including non-served energy costs) for consumers without micro-CHP units.

- The difference between utility (assumed constant) and electricity costs plus operational costs for consumers owning micro-CHP units.

The expression used for calculating system's production cost is given by:

$$\begin{aligned}
\textit{System energy production cost [\$/yr]} &= \sum_{g}\sum_{h}\left(SRMP_h^{iter} - VC_{h,g}\right)\cdot Q_{h,g}^{elec} \\
&- \left(\sum_{h}\left(d_h\cdot\left(1+gr_y\right)^{y} - \sum_{dms,c} Q_{h,dms,c}^{elec}\right)\cdot SRMP_h^{UP,iter} + \sum_{h} Q_h^{nse}\cdot voll\right) \\
&- \sum_{h}\left(\sum_{dms,c} Q_{h,dms,c}^{elec}\cdot VC_{h,dms,c} + \sum_{aux,c} Q_{h,aux,c}^{heat}\cdot VC_{h,aux,c}\right)
\end{aligned}$$

Where, VC is the total variable cost of operating conventional power plants, micro-CHPs and conventional heating systems respectively, including not only fuel costs and variable O&M, but also CO2 emissions costs for the year under analysis.

4. System's peak load reduction:

The contribution of micro-CHPs to peak load reduction is estimated for the 20 hours with the highest system electric load, for every month of the year. Thus, the reduction is estimated as the ratio of electricity produced by micro-CHPs to the electric demand of the system during the 20 hours of highest demand. The expression is given by:

$$\textit{Peak load reduction [\%/mo]} = \frac{\sum_{h}\left(\sum_{dms,c} Q_{h,dms,c}^{elec}\right)}{\sum_{h}\left(d_h\cdot\left(1+gr_y\right)^{y}\right)}\ \forall h \in \textit{20 highest load}$$

In addition to these metrics at the system level, we calculated similar metrics at the residential level for each customer class:

1. Residential customer's CO2 emissions:

Similar to above, CO2 emissions are estimated considering emissions derived from fuel used by micro-CHPs and conventional heating units. However, as customers produce electricity from micro-CHPs, there is an effect on the system's emissions – because of a change in the energy portfolio - that is included in the calculation of emissions per residential customers. The expression, per customer class, is given by:

$$
\begin{aligned}
CO2_c^{Residential}\ [ton/yr] = \ & \sum_{h,dms} Q_{h,dms,c}^{elec} \cdot ef_{dms,c} \cdot hr_{dms,c}^{elec} \\
& + \sum_{h,aux} Q_{h,aux,c}^{heat} \cdot ef_{aux,c} \cdot hr_{aux,c}^{heat} \\
& + (Em_{Qg\_sys}^{chp\_case} - Em_{Qg\_sys}^{af0\_case}) \quad \forall c
\end{aligned}
$$

Where,

$Em_{Qg\_sys}^{chp\_case}$ and $Em_{Qg\_sys}^{af0\_case}$ are the CO2 emissions from the electric energy portfolio in the case with and without micro-CHP case respectively.

2. Residential customer’s energy efficiency:

Energy efficiency at household level is estimated as the ratio of useful energy used on-site to the total fuel used by the energy system. Here, we include the efficiency effect of the electricity acquired from the grid by residential customers. Thus, the expression used for calculating system’s efficiency is given by:

$$
Efficiency_c^{Residential}\ [\%/yr] = \frac{\left(\sum_{h} e_{h,c}^{imp} + \sum_{h,dms} \left(Q_{h,dms,c}^{elec} + Q_{h,dms,c}^{heat} - Q_{h,dms,c}^{heat\_waste} \right) + \sum_{h,aux} Q_{h,aux,c}^{heat} \right)}{\left(\sum_{h,g} \left(fuel_{h,g} \right) \cdot \left(\%_{h,c}^{elec} \right) + \sum_{h,dms} fuel_{h,dms,c} + \sum_{h,aux} fuel_{h,aux,c} \right)} \quad \forall c
$$

Where,

$\%_{h,c}^{elec}$ is the proportion of electricity being purchased from the grid every hour h per customer class c. This term is calculated as $\%_{h,c}^{elec} = \dfrac{e_{h,c}^{imp}}{\sum_{g} Q_{h,g}^{elec}} \ \forall c$. We note here that the effect of energy network losses is not included in this expression.

3. Residential customer’s energy cost:

As explained in Chapter 3, the energy cost considers the total cost operational cost for the final customers of meeting their electricity and heat requirements:

- Variable costs derived from the operation of conventional heating systems and micro-CHPs.
- Electricity costs derived from power purchase to meet on-site electric requirements not met by micro-CHPs. Payments are based on the final retail

electricity price given to residential customers, which is derived from the system's short-term marginal price plus other additional charges[166].

The expression used for calculating customer's energy cost is given by:

$$EC_c^{Residentid}\ [\$/yr] = \sum_h e_{h,c}^{imp} \cdot SRMP_h^{UP+GC+NCE,iter-1} + \sum_{h,dms} Q_{h,dms,c}^{elec} \cdot VC_{h,dms,c} + \sum_{h,aux} Q_{h,aux,c}^{heat} \cdot VC_{h,aux,c} \quad \forall c$$

Where, $VC_{h,dms,c}$ and $VC_{h,aux,c}$ are the total variable cost of operating micro-CHPs and conventional heating systems respectively per hour h and customer class c. This term includes not only fuel costs and variable O&M, but also CO2 emissions costs for the year under analysis.

4. Residential customer's natural gas consumption:

Annual residential natural gas consumption is estimated taking into account fuel used to operate micro-CHPs and conventional heating devices. The expression used for calculating natural gas consumption per customer class is given by:

$$NG_c^{on-site\,residentid}\ [MWh/yr] = \sum_{h,dms} fuel_{h,dms} + \sum_{h,aux} fuel_{h,aux} \quad \forall c$$

These metrics are used to quantify and compare the impact of having a large number of micro-CHPs with the case of not having them within a particular energy system. As mentioned above, the same metrics help us to understand the value of this technology under different electricity retail schemes. In particular, we look at two different rates[167]:

- Flat rate, where residential customers received the same electricity rate for every hour of the day,
- Hourly rate where customers get a price of electricity that changes for every hour of the day.

In addition, we also look at the case where the retail electricity price includes generation capacity payments, and transportation and distribution charges in the form of additional energy charges. This case is of interest, as we want to explore the impact of additional energy charges (unrelated to the technologies variable costs) on the system dispatch's economic efficiency.

In the following sections we first show the results obtained from the short-term (ST) model for the case with micro-CHP (*CHP case*) against the case without micro-CHP (*AF0 case*), then the results for the different electricity retail rates. Both analyses will focus on the overall system's results and customer class' results.

---

[166] The SRMP includes an energy loss factor to represent the economic effect of network losses in the system. Other charges include uplift and generation capacity charges, and transmission and distribution costs. For details refer to Chapter 5 on the end-user electric tariff design.

[167] The case of time-of-use rate, where customers receive a differentiated rate per peak or off-peak hours of the day, has been left for future research.

6.2.2. Short-term results

From the long-term (LT) generation expansion model, we obtained the energy portfolio for the particular scenario of having 10% micro-CHP penetration at the end of the time horizon; under high CO2 price and high natural gas retail price conditions[168] (refer to section "Reference case"). Recall that the micro-CHP technology of choice under these particular conditions was the micro-CHP with medium HPR2.7 for both classes of customers.

As explained in Chapter 5 the electric system to be used in the ST model is constructed using the installed capacity and a typical unit size per conventional electric technology. Thus, the case without micro-CHP (AF0 case) has a total of 195 electric plants, while the case with micro-CHP (CHP case) has a system with 183 plants. Regarding the number of households using micro-CHPs, this is based on the installed capacity outcome provided by the LT model and the optimum size of the micro-CHP. The optimum micro-CHP size is given by the relationship between the residential on-site energy loads, energy operation costs and fixed capital costs. Thus, the results for each customer class are (for details see "Appendix C.12. Micro-CHP optimum size analysis for customer class C1 & C2")[169]:

- For customer class C1 the micro-CHP size is 0.8kWe with HPR 2.7. Since the installed capacity is 2,171[MW] for micro-CHP HPR2.7, the number of householders operating this technology is 2,713,113 customers.

- For customer class C2 the micro-CHP size is 1.3kWe with HPR 2.7. Since the installed capacity is 2,181[MW] for micro-CHP HPR2.7, the number of householders operating this technology is 1,678,000 customers.

With this data, we use the short-term model to analyze the hourly dispatch patterns for one typical week of every month of the year. Then we compare the case of not having micro-CHP as an energy alternative against the case of having 10% micro-CHP penetration, and we look at metrics such as CO2 emissions, energy efficiency, production and energy costs to understand the value of micro-CHPs for residential customers and the overall energy system.

6.2.2.1. System's results

Results show that, in a scenario with 10% penetration of micro-CHP in installed capacity, this technology contributes about 17% of total annual electric generation for year t20, with the lowest contribution during summer. When we compare the case with micro-CHP against the case without micro-CHP, we note that the operation

[168] The CO2 price is 98.74 [$/ton], while the natural gas retail price is 17.75[$/MMBtu] at the end of the time (refer to Chapter 5 for more details and references).
[169] We need to note that for the cases without micro-CHP (AF0 case), we will be looking at the same number of users that was estimated to have micro-CHPs for each class.

of micro-CHPs mostly impacts the operational pattern of the natural gas plants. In particular we see that GasCCs are used less all year round, while GasCTs increase their outputs during summer and some days during spring/fall. The operation for the different seasons is as follows:

- In winter, micro-CHP operation is quite constant as the residential heat component is high and the electricity prices are high enough to favor the production electricity as well. For *February* for example (see Figure 6.2.1), their electric capacity factor is over 95%, with about 20% of participation within the electric generation mix, and energy efficiency of about 72% at a system-level and over 85% at residential-level when considering both electricity and heat. Excess heat less than 0.2% of the micro-CHP production.

- In summer, the operation of micro-CHP is sometimes irregular especially during weekends or off-peak hours when electricity prices are lower and consumers prefer to buy power from the grid. Even though the heat component is quite low, as the electricity prices are so high during peak periods the residential customers prefer to operate their machines with the consequence of having excess heat that is not used to meet their on-site heat load. For *August* for example (see Figure 6.2.2), the micro-CHPs electric capacity factor is less than 65%, with about 13% of participation within the electric generation mix. The energy efficiency is only about 47% at system-level, and about 52% at residential-level when considering both electricity and heat. There are two reasons for having low energy efficiency: (i) As electricity is very high and heat low during summer, efficiency will be dominated by the efficiency of producing electricity by conventional power generators, and (ii) as micro-CHPs are inefficiently operated because of extremely high electricity prices, the efficiency gets worse because of the excess heat being produced but not used. Excess heat is about 23% of the micro-CHP heat production (see green areas in Figure 6.2.2c). *This inefficient operation from the economic point of view is analyzed below.*

- In spring & fall, the operation of micro-CHPs is quite irregular during the entire week. As the heat component can be important during some hours of the day, residential customers turn on their machines during some hours of the day to store heat in the tank when prices are high and use the heat later in the day[170]. For May for example (see Figure 6.2.3), the micro-CHPs electric capacity factor is around 60%, with about 14% of participation within the electric generation mix. The energy efficiency is only about 50% at system-level, and about 60% at residential-level when considering both electricity and heat. Excess heat is less than 0.3% of the micro-CHP heat production.

[170] As we pointed out in Chapter 4, this type of operation may cause an excessive wear and tear of the machine and it may not be optimal from the technical point of view.

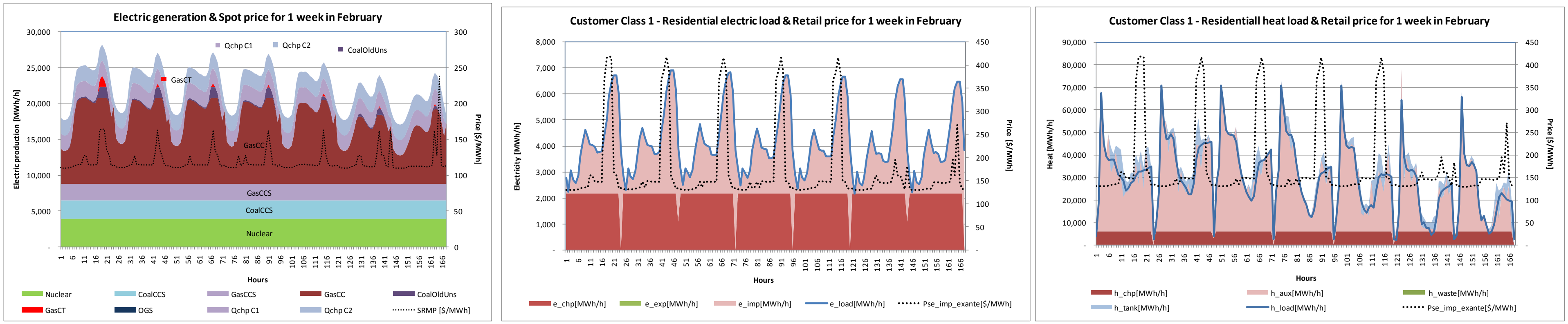


Figure 6.2.1: Micro-CHP operation during 1 week in winter (February) within electric system & residential customers

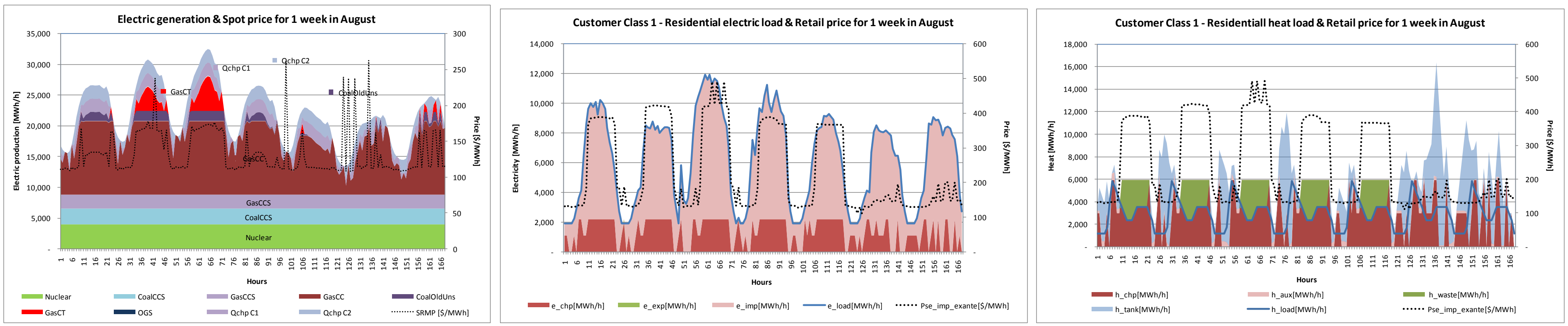


Figure 6.2.2: Micro-CHP operation during 1 week in summer (August) within electric system & residential customers

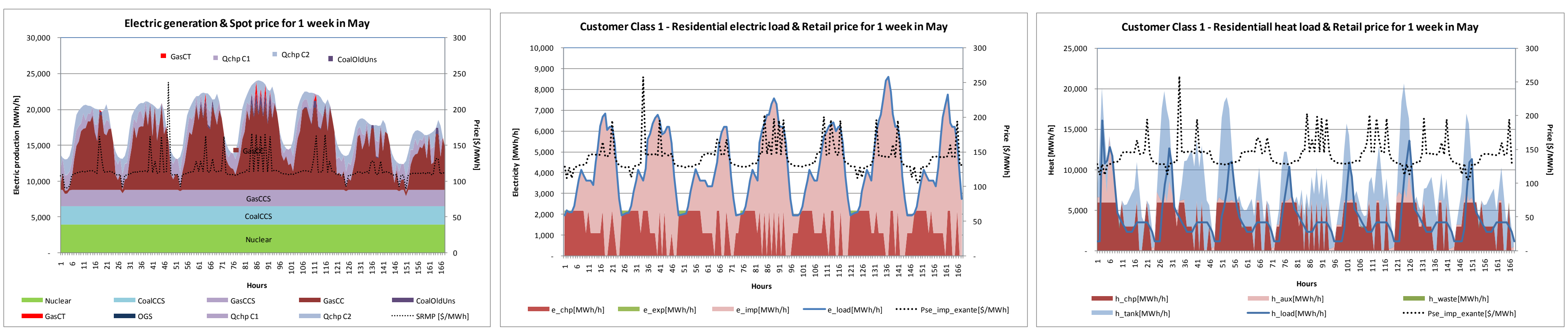


Figure 6.2.3: Micro-CHP operation during 1 week in spring (May) within electric system & residential customers

When we look at the system-wide metrics and compare them for the cases with and without micro-CHP (*CHP case* vs. *AF0 case* respectively), results show:

- In general we see that total system's CO2 emissions increase during winter because of the large heat component. When comparing CHP and AF0 cases we see that the system's CO2 emissions decrease every month of the year for the case with micro-CHP (see Figure 6.2.4), with the largest reductions during winter when the utilization of micro-CHPs is greater and the produced heat is fully used, i.e. no excess heat. *Annual CO2 emissions reduction is about 5.0% for a 10% micro-CHP HPR2.7 penetration*.

- We note that the total system's efficiency decreases substantially during summer because the heat demand is low and most of the efficiency comes from the electric power system's efficiency that supplies electricity. As the heat requirements are substantial in winter, energy efficiency considers not only fuel efficiency from electric power plants, but also fuel efficiency from conventional heating devices and micro-CHPs to supply heat and electricity. When comparing both cases we see that the system's energy efficiency is increased every month of the year (see Figure 6.2.5), with the biggest improvements mostly during winter. *Annual energy efficiency increment is about 3.5% for a 10% micro-CHP HPR2.7 penetration*.

- With the penetration of micro-CHPs we see that the system's energy production costs decreases almost every month of the year (see Figure 6.2.6), with the largest reductions during winter as micro-CHPs are used most of the time and the produced electricity and heat are fully used to meet on-site demands. We also note that the system's costs increase during summer as micro-CHPs are being used inefficiently because consumers prefer to produce electricity with the purpose to avoid the extremely high prices during peak hours (this effect is explained below). *Annual energy production costs reduction is about 1.4% for a 10% micro-CHP HPR2.7 penetration.*

- We also observe that micro-CHPs help to decrease the system's peak load every month of the year (see Figure 6.2.8). We note that for the months for which the electric system has the highest demand (summer) their contribution to load reduction is also important. However, as we will see at the residential level, this high electricity production comes coupled with a very inefficient operation of the micro-CHPs with high levels of excess heat. *Summer peak load reduction about 16.0% for a 10% micro-CHP HPR2.7 penetration, with about 22% excess heat of micro-CHP heat production.*

- Figure 6.2.7 shows the electric power technologies displaced by the operation of micro-CHPs. Annual results show that micro-CHPs compete mostly with GasCC, with some generation increment from GasCT. Looking at the monthly results we see in addition that the generation of other technologies - such as GasCT and Coal - increases during summer and fall:

  - During *winter*, as the heat component is very high, the operation of micro-CHPs is quite constant and operates at maximum capacity most of the time. We observe that micro-CHPs displace production from GasCC. Production from Coal is also displaced, although marginally, as their fixed operational costs (start-up & no-load costs) do not allow more displacement in the daily economic dispatch[171].

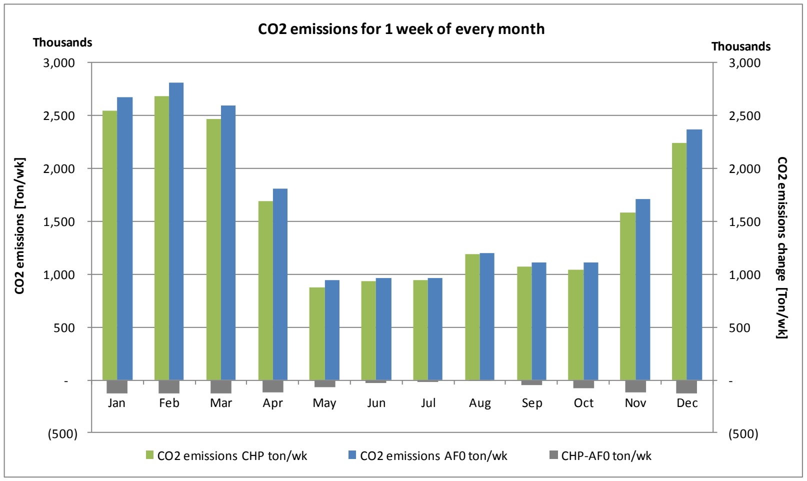
  - During *summer*, as the heat component is lower, the operation of micro-CHPs is more irregular and sensitive to the electricity prices received by residential customers. Under these conditions, micro-CHPs have a lower electric capacity factor, with a fluctuating operation especially during off-peak hours of the day. We observe that micro-CHP displaces GasCC while increases the production of GasCT and Coal. During off-peak hours, micro-CHPs displace production from GasCC. During peak hours, we observe less power from GasCC (as a result of the capacity expansion process) and, since the electricity production of micro-CHPs is lower than expected at some hours, Coal and GasCT increase their production to meet high demand.

Finally, the aggregated annual results for the overall energy system (heat & electricity) are summarized in Table 6.2-1:

Annual effects with 10% micro-CHP HPR2.7 penetration	**System-wide metrics**
CO2 emissions	~ 5.0% reduction
Energy efficiency[172]	~ 3.5% increment
System production cost	~ 1.4% reduction
Summer peak load reduction	~ 15.5% reduction
Contribution to system electric demand	~16.9% annual (~13.4% summer)
Micro-CHP capacity factor	~78% annual
Summer micro-CHP waste heat	~22% summer
Technology change	Mostly GasCC generation reduction all year round Some GasCT & Coal generation increment during summer

Table 6.2-1: Summary of annual system-wide effects with large-scale penetration of micro-CHPs

[171] Sometimes the UC model prefers to keep the Coal units on. Even though their variable cost are higher than GasCCs, their fixed operational costs are high enough that prevent the system to turn them on and off in a more flexible manner.
[172] Values are expressed as percentage change.



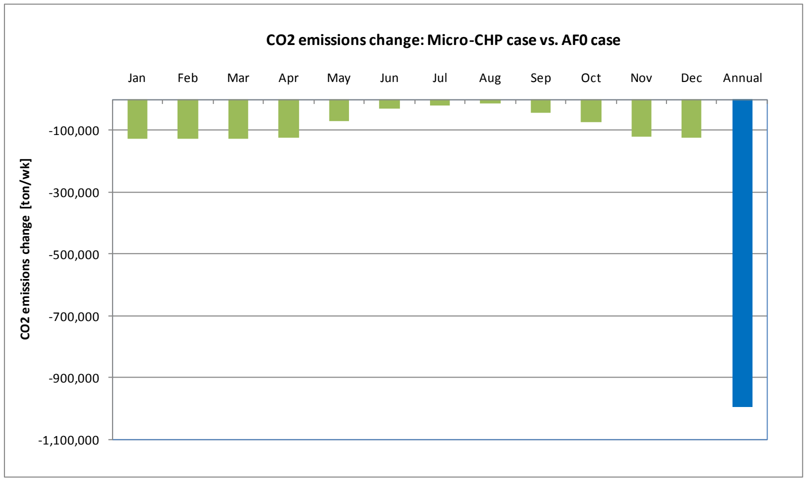
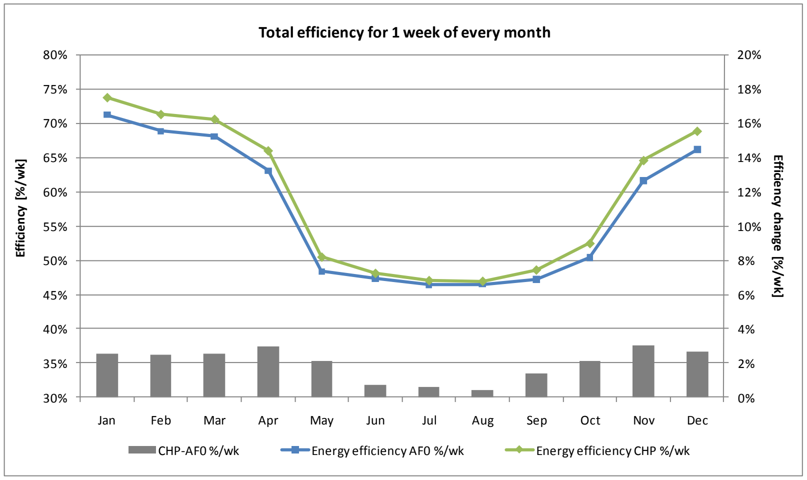


Figure 6.2.4: Comparative results for micro-CHP vs. no micro-CHP cases - System's CO2 emissions Total & Change per month



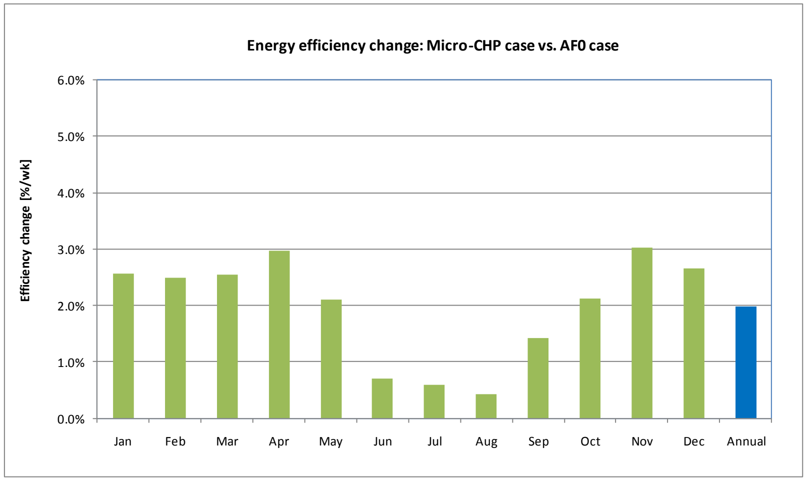


Figure 6.2.5: Comparative results for micro-CHP vs. no micro-CHP cases - System's energy efficiency Total & Change in percentage points per month

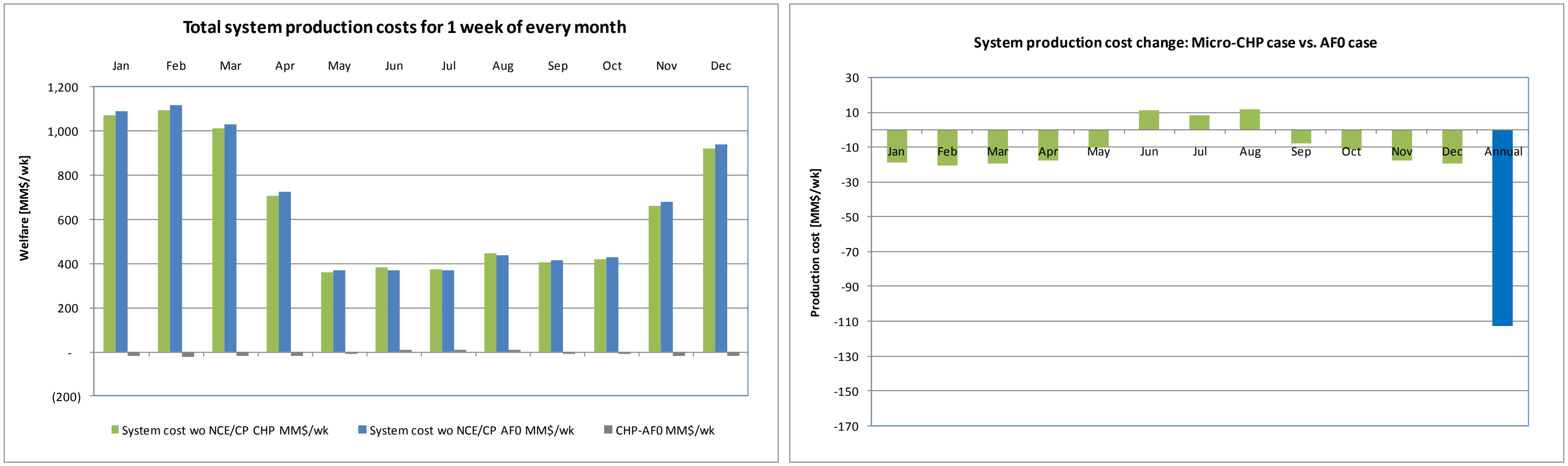


Figure 6.2.6: Comparative results for micro-CHP vs. no micro-CHP cases - System's production costs Total & Change per month

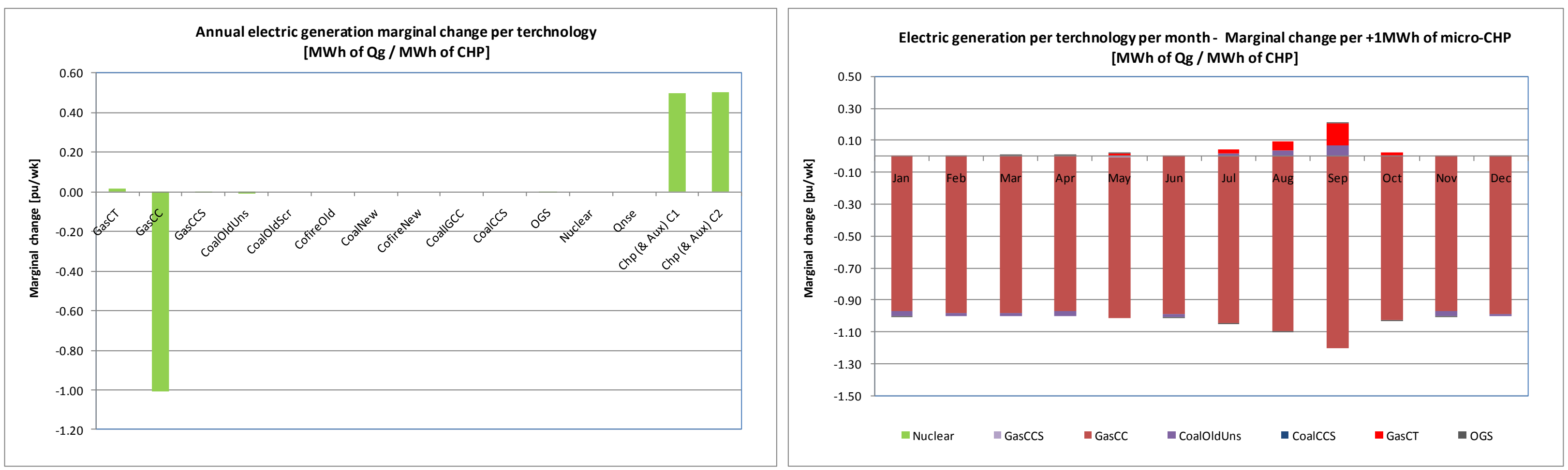


Figure 6.2.7: Electric generation marginal change per+1MWh of micro-CHP for the year & per month

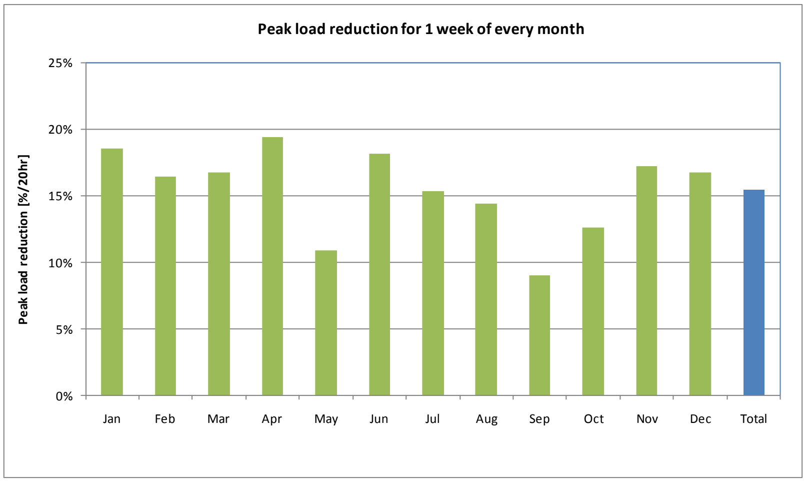


Figure 6.2.8: System's Peak load reduction per month for micro-CHP case

We mentioned that, particularly during summer, we saw an inefficient operation of micro-CHPs. According to the methodology explained in Chapter 5, the retail prices passed to customers include not only operating variable costs but also network & capacity payments costs in the form of energy charges during peak hours. These additional charges increase the electricity prices received by end-users to very high values during peak times, with the consequent incentive to produce electricity using micro-CHPs instead of buying it to the grid. However, this micro-CHP production pattern comes at the expense of *increasing the system's production costs and increasing levels of excess heat during summer*.

Thus, when we look at the results of the baseline CHP case (*CHP case*) and the modified CHP case without network costs and generation capacity payments (*CHP case w/o NC&GCP*), we observe the following:

- System's energy efficiency improves during summer months as micro-CHP heat waste is dramatically reduced (see June, July, and August in Figure 6.2.9).

- System's energy production costs decrease all year round, even during summer (see June, July, and August in Figure 6.2.10). Under the modified CHP case, micro-CHPs are being used more efficiently as now micro-CHPs compete with conventional power plants based only on their operational variables costs.

- Micro-CHP contribution to system's peak load reduction decreases during summer with respect to the baseline case (see June, July, and August in Figure 6.2.11). Micro-CHPs do not produce as much electricity during these months as the retail price that customers receive is lower in this modified case. We also see a more efficient micro-CHP operation as waste heat is dramatically reduced with the new retail prices (see results at residential level in Figure 6.2.13, Figure 6.2.14).

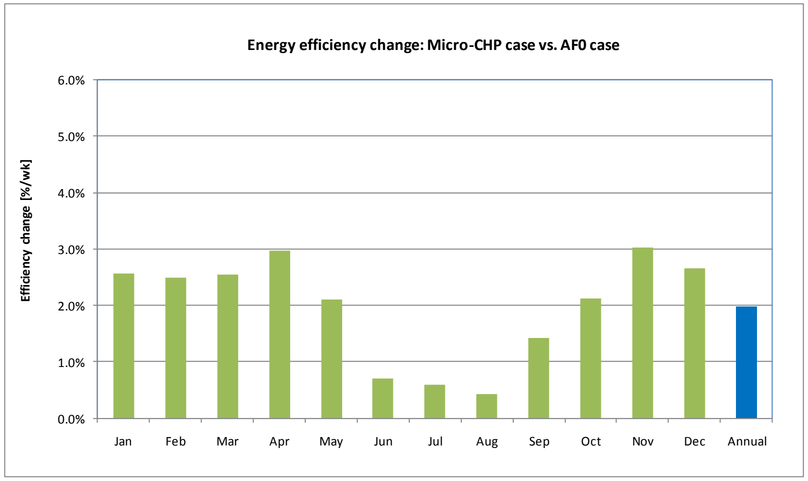
- Regarding the impact on the conventional electric power units, we observe that as micro-CHPs generate less electricity during summer, mostly GasCTs increase their production (see August in Figure 6.2.12). Generation increment from GasCC is not feasible as there is no more generation capacity available.

Finally, the aggregated annual results for the energy system for the case without NC & GCP charges are summarized in Table 6.2-2:

Annual effects with 10% micro-CHP HPR2.7 penetration	**System-wide metrics CHP case without NC & GCP**
CO_2 emissions	~ 5.1% reduction
Energy efficiency[173]	~ 3.7% increment
System production cost	~ 2.0% reduction
Summer peak load reduction	~ 9.5% reduction
Contribution to system electric demand	~15.8% annual (~10.4% summer)
Micro-CHP capacity factor	~73% annual
Summer micro-CHP waste heat	~0.13% summer
Technology change	Mostly GasCC generation reduction all year round Some GasCT & Coal generation increment during summer

Table 6.2-2: Summary of annual system-wide effects with large-scale penetration of micro-CHPs

[173] Values are expressed as percentage change.



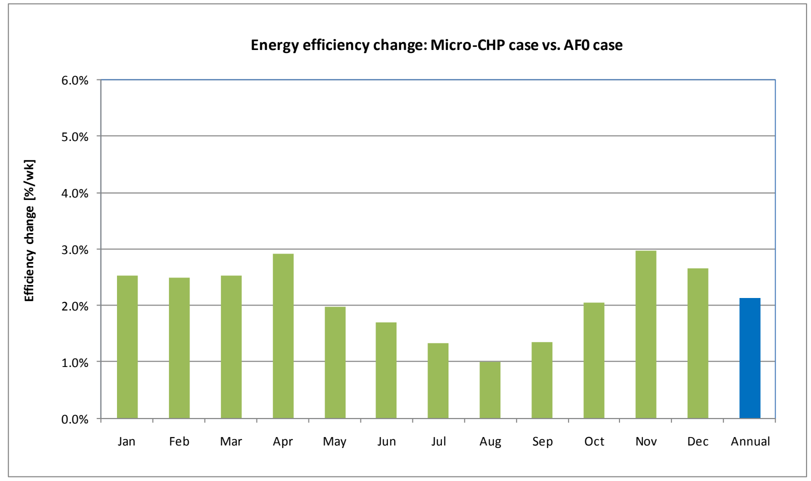
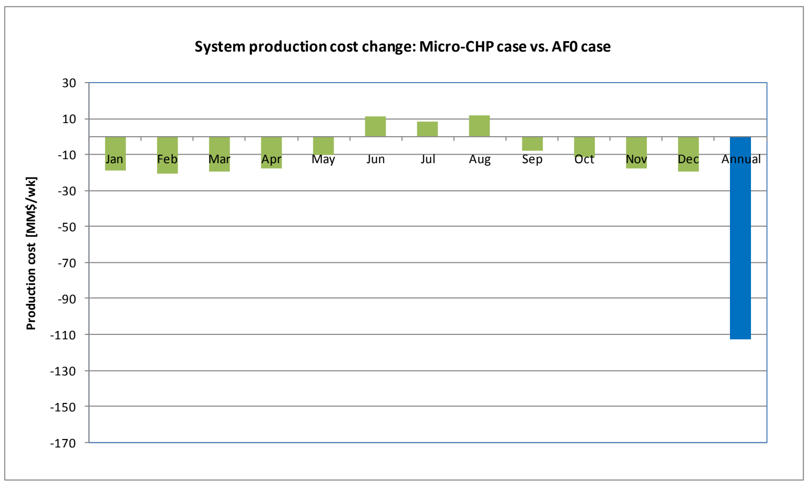


Figure 6.2.9: System's energy efficiency (percentage points) - CHP case &. CHP w/o NC&GCP case vs. AF0 case



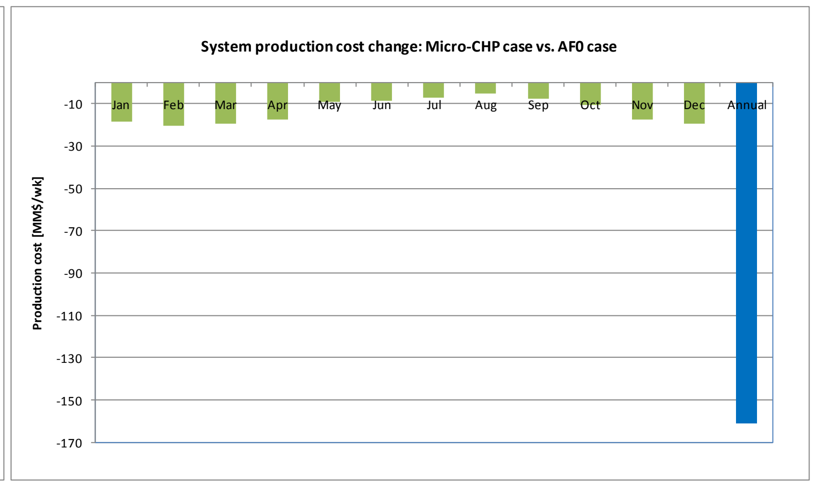
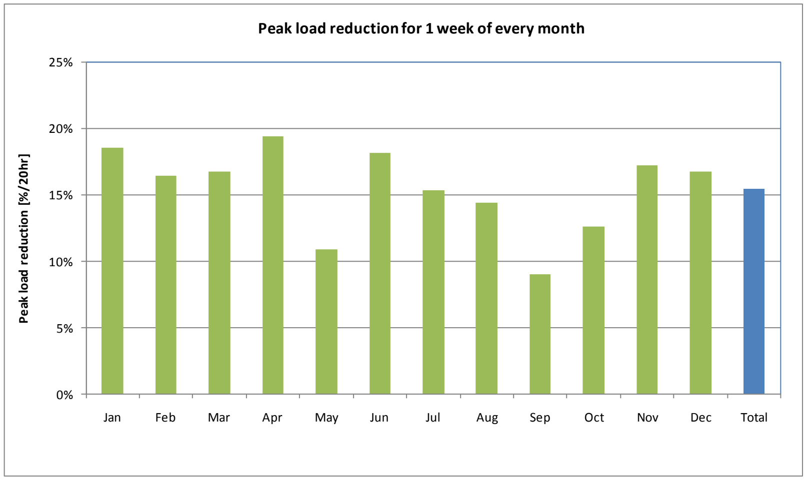


Figure 6.2.10: System's energy production costs - CHP case & CHP w/o NC&GCP case vs. AF0 case



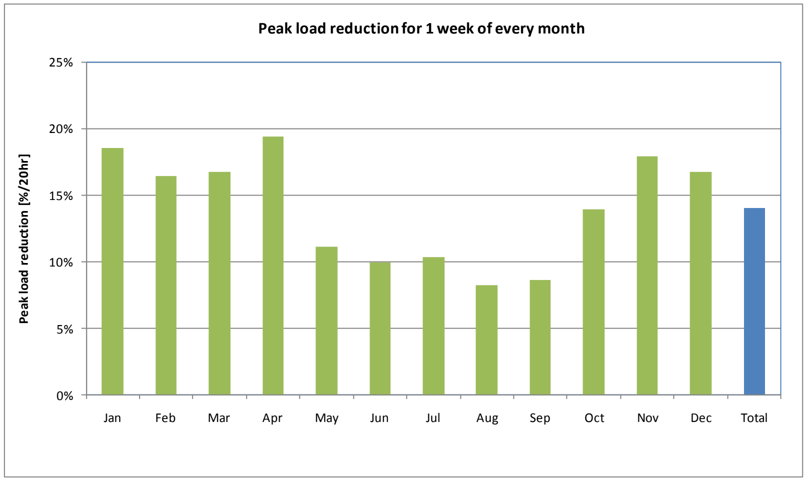
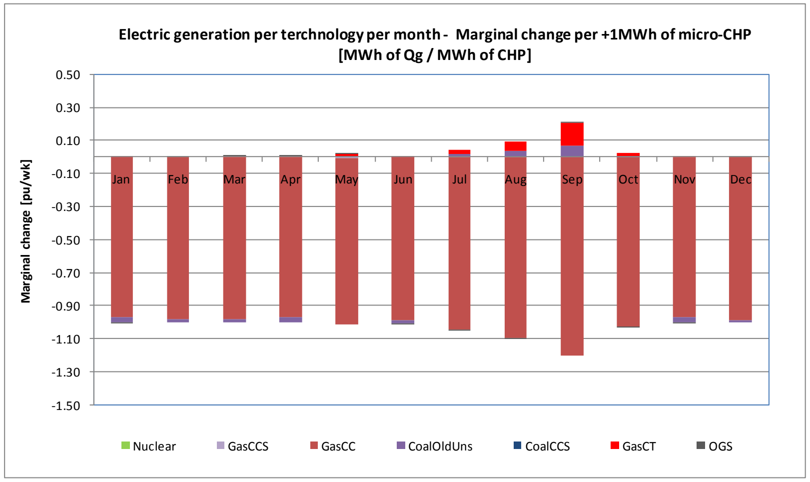


Figure 6.2.11: System's electric peak load reduction - CHP case & CHP w/o NC&GCP case vs. AF0 case



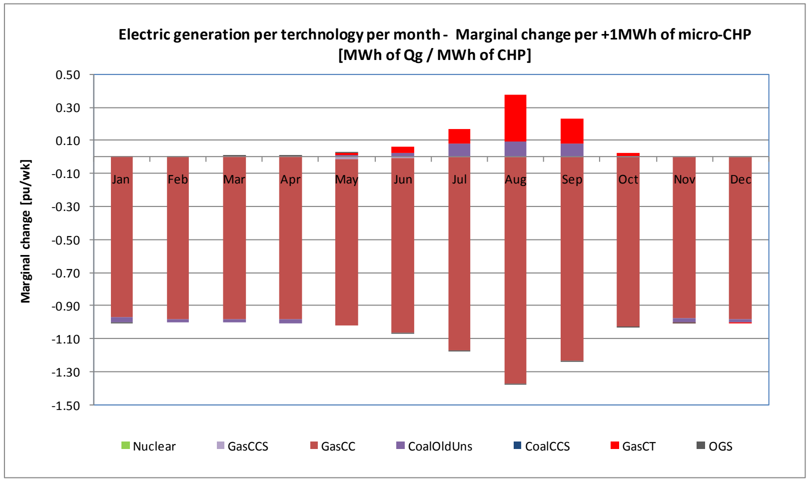


Figure 6.2.12: Electric generation marginal change per+1MWh of micro-CHP per month - CHP case & CHP w/o NC&GCP case vs. AF0 case

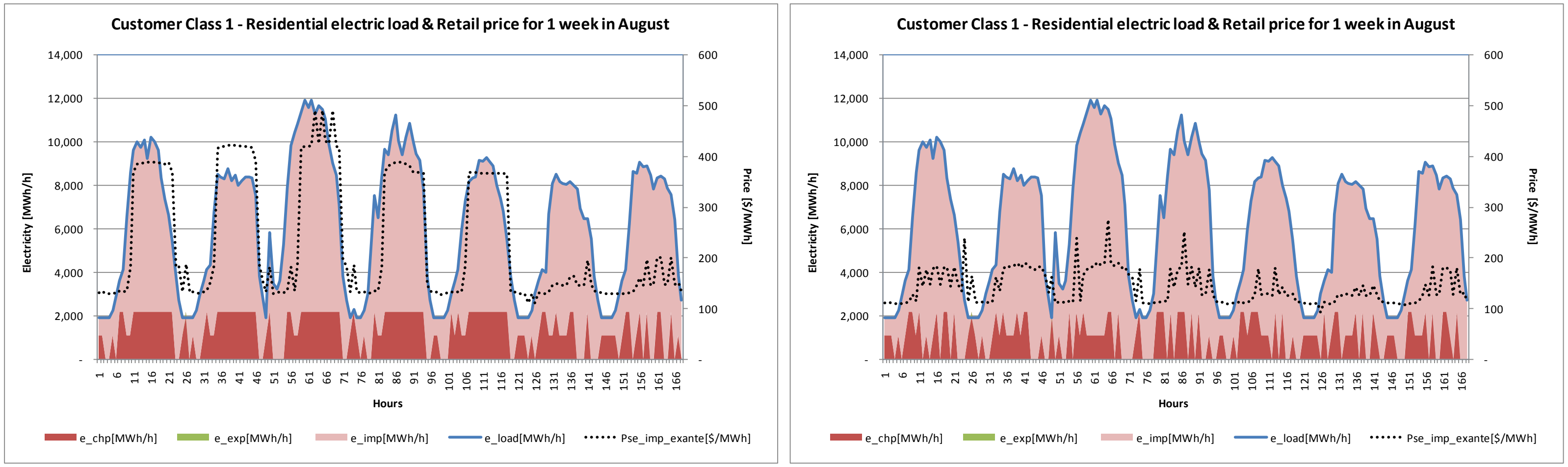


Figure 6.2.13: Micro-CHP electric generation during August - CHP case vs. CHP w/o NC&GCP case

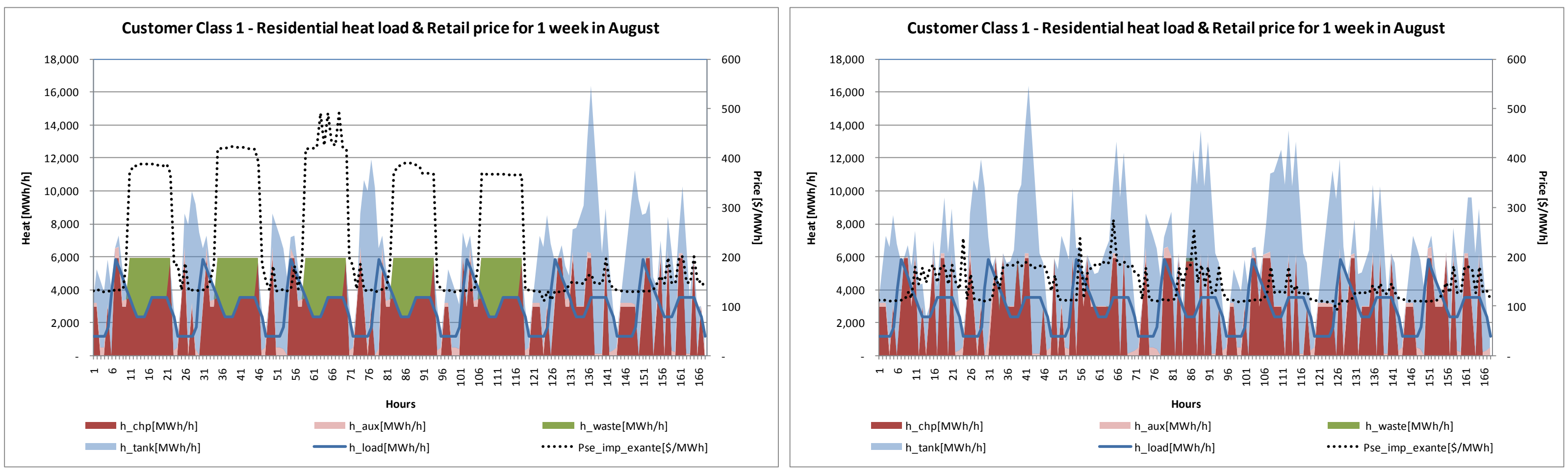


Figure 6.2.14: Micro-CHP heat generation during August - CHP case vs. CHP w/o NC&GCP case

6.2.2.2. *Residential customers' results*

The short term model analyzes two types of residential customers, customer class C1 and C2. Each class has micro-CHP units with a particular size that is optimal for their energy load requirements, according to their energy production and fixed costs. As we mentioned earlier, the electricity capacity determined by the capacity expansion decision and the size of the units, specify the number of residential customers within each class to be analyzed. In Table 6.2-3, we show some characteristics of the residential customers being analyzed are:

Residential customers characteristics	Customer class C1	Customer class C2
% system's electric demand	23%	25%
Number users	2,713,113	1,678,000
Micro-CHP technology	HPR2.7	HPR2.7
Micro-CHP unit size	0.8kWe	1.3kWe

Table 6.2-3: Residential customers' characteristics

Results show that residential energy requirements (electricity & heat) are not fully supplied by micro-CHPs. Residential customers need to buy additional electricity from the grid and fuel to operate auxiliary heating equipment. Table 6.2-4 shows the contribution by micro-CHPs to meet on-site residential energy requirements:

Micro-CHP contribution to energy demand	Customer class C1	Customer class C2
% electric demand	36%	34%
% heat demand	31%	38%

Table 6.2-4: Percentage of residential electric & heat loads supplied by micro-CHPs (numbers consider only useful energy used for on-site demand)

The monthly operation of micro-CHPs is shown in Figure 6.2.15 and Figure 6.2.16 for each customer class. We see that heat requirements are significant during winter and much lower in summer, and consequently micro-CHP production is higher in *winter* than in summer. We note that micro-CHP generation is limited by the size of the unit, so the production in winter cannot be more as it is working at full capacity. During *summer* we still see an important operation of the micro-CHPs units as they try to cover the heat demand (given mostly by hot water requirements). We also see excess heat (green bars in the figures) mostly given by the inefficient operation of the micro-CHP units in response to the high prices during summer (effect above discussed).

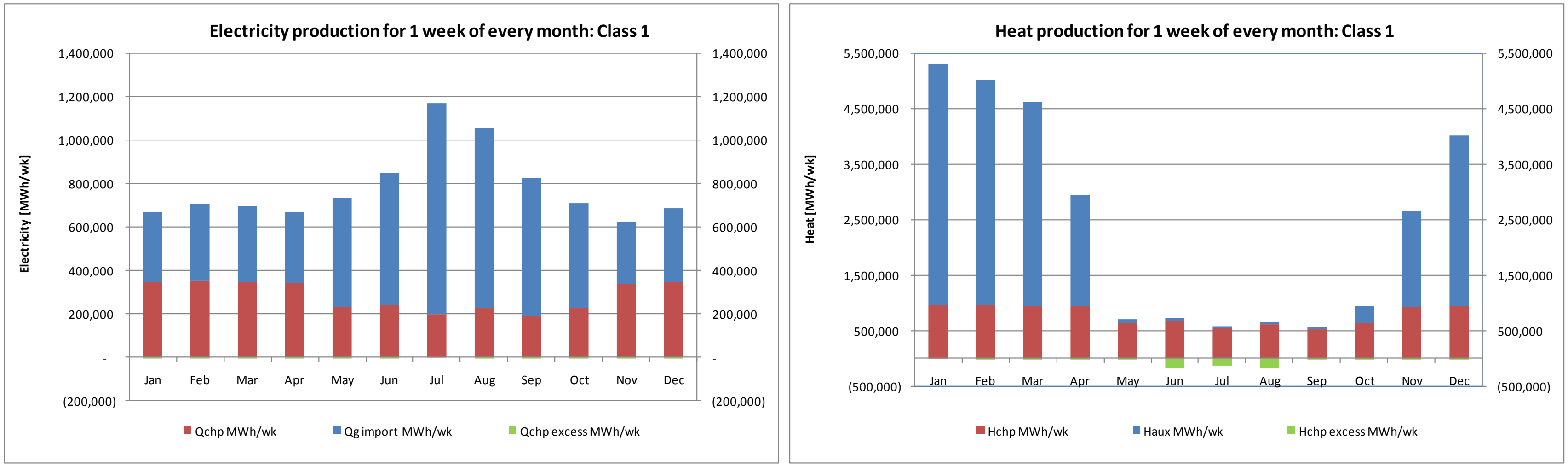


Figure 6.2.15: Total energy load supplied by conventional and micro-CHP technologies for Customers Class C1

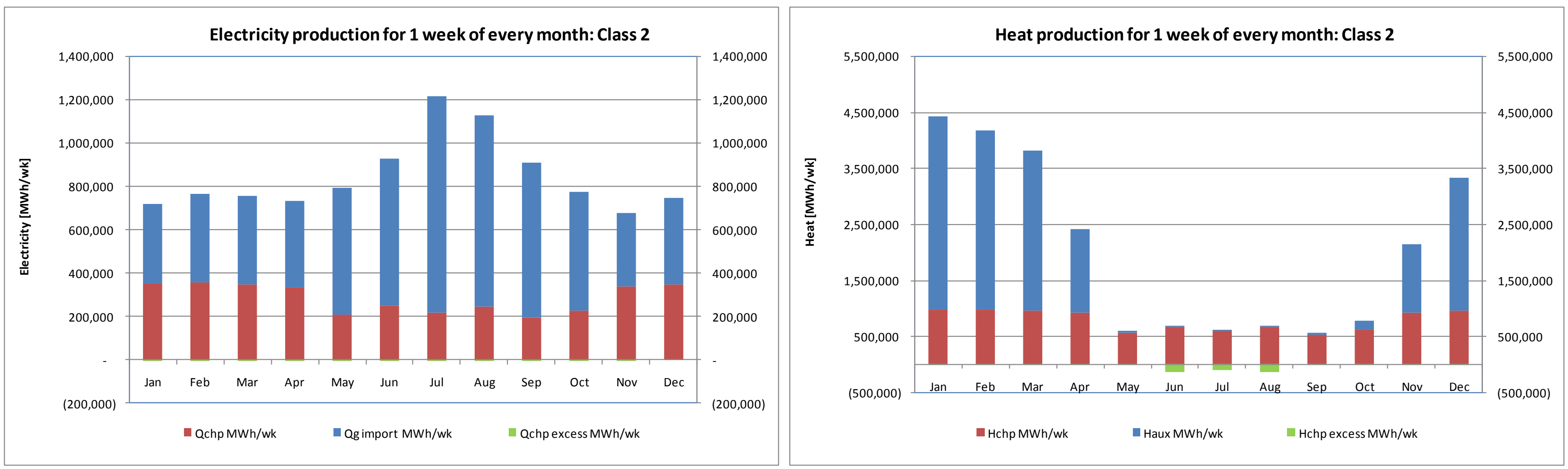


Figure 6.2.16: Total energy load supplied by conventional and micro-CHP technologies for Customers Class C2

When we look at the residential metrics and compare them for the cases with and without micro-CHP (CHP vs. AF0 cases respectively), results show:

- Total residential CO2 emissions - in both cases - increase during winter because of the heat requirements. However, the operation of micro-CHPs reduces emissions in almost every month of the year for both classes of customers (see Figure 6.2.17) with the largest reductions during winter. As we mentioned, in this case where retail prices include network and capacity payments costs in the form of energy charges, we observe very few emissions savings during summer due to heat being produced but not used for meeting on-site requirement (excess heat because of inefficient operation). *Annual CO2 emission reductions are 6.0% and 7.2% for customer class C1 and C2 respectively.*

- The operation of micro-CHPs increases the energy efficiency in every month of the year for both classes of customers, with the lowest improvements during summer (see Figure 6.2.18). *Annual energy efficiency improvements are about 7.5% for both customer class C1 and C2 respectively*.

- In general, residential energy costs are higher in winter as they include the additional costs of supplying heat during those months. In summer, costs increase due to air conditioning requirements (for both CHP and AF0 cases). The operation of micro-CHPs, as we saw in Chapters 3 and 4, helps to reduce the energy costs for residential customers in every month of the year for both classes. The largest costs reductions occur in winter, while in summer we still see important cost reductions. As in this CHP case electricity prices are high because of NC & GCDP costs, users operate their micro-CHPs to avoid buying the expensive electricity from the grid (see Figure 6.2.19). *Annual energy cost reductions are about 5.9% and 6.4% for customer class C1 and C2 respectively, including savings related to network and capacity payment costs.*

- Finally, we see that the operation of micro-CHP considerably increases on-site consumption of natural gas every month (see Figure 6.2.20). Even during summer we see a fuel increase as micro-CHP owners operate the units to avoid buying expensive electricity from the grid because of the high electricity prices. *Annual natural gas fuel consumption increases about 15% and 18% for customer class C1 and C2 respectively*.

Results for customer class C2 can be found in “Appendix C.13. Comparative results for CHP vs. AF0 cases – Customer class C2”.

Finally, the aggregated results for each customer class are summarized in Table 6.2-5:

Annual effects with 10% micro-CHP HPR2.7 penetration	Residential metrics for C1	Residential metrics for C2
CO2 emissions	~ 6.0% reduction	~ 7.2% reduction
Energy efficiency[174]	~ 7.2% increment	~ 7.7% increment
Energy cost	~ 5.9% reduction	~ 6.4% reduction
NG consumption	~ 15.5% increment	~ 18.3% increment
Summer micro-CHP excess heat	~ 24.4% summer	~ 19.4% summer
Contribution to electric demand	36% annual	34%
Contribution to heat demand	31% annual	38%

Table 6.2-5: Summary of annual effects per customer class with large-scale penetration of micro-CHPs

[174] Values are expressed as percentage change.

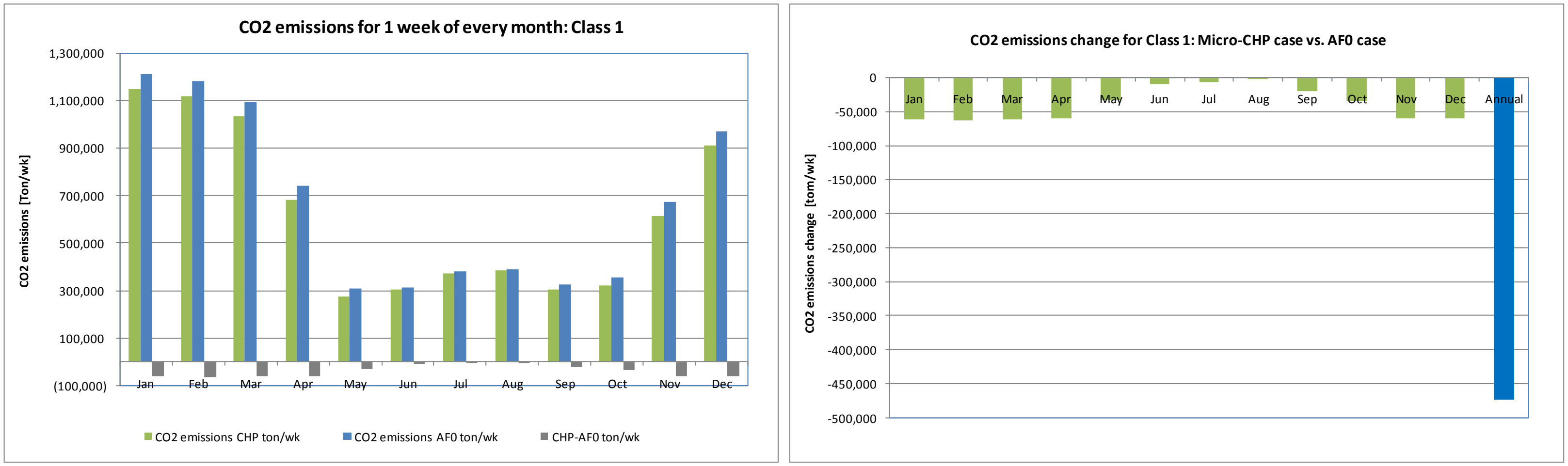


Figure 6.2.17: Comparative results for micro-CHP vs. no micro-CHP cases – Customer Class C1's CO2 emissions Total & Change per month

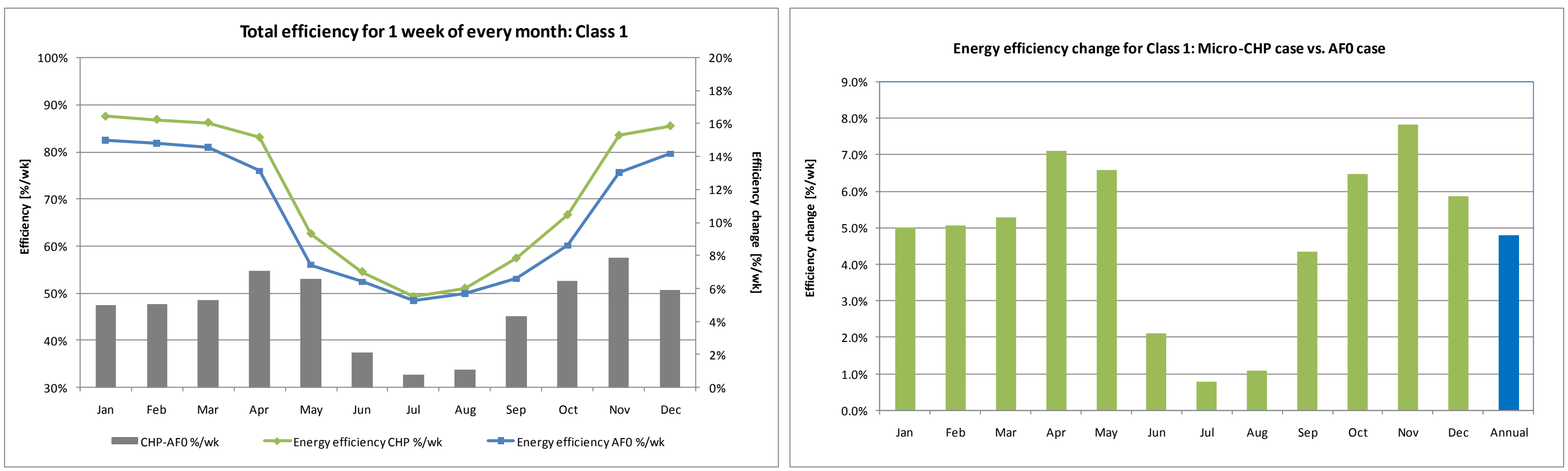


Figure 6.2.18: Comparative results for micro-CHP vs. no micro-CHP cases – Customer Class C1's energy efficiency Total & Change in percentage points per month

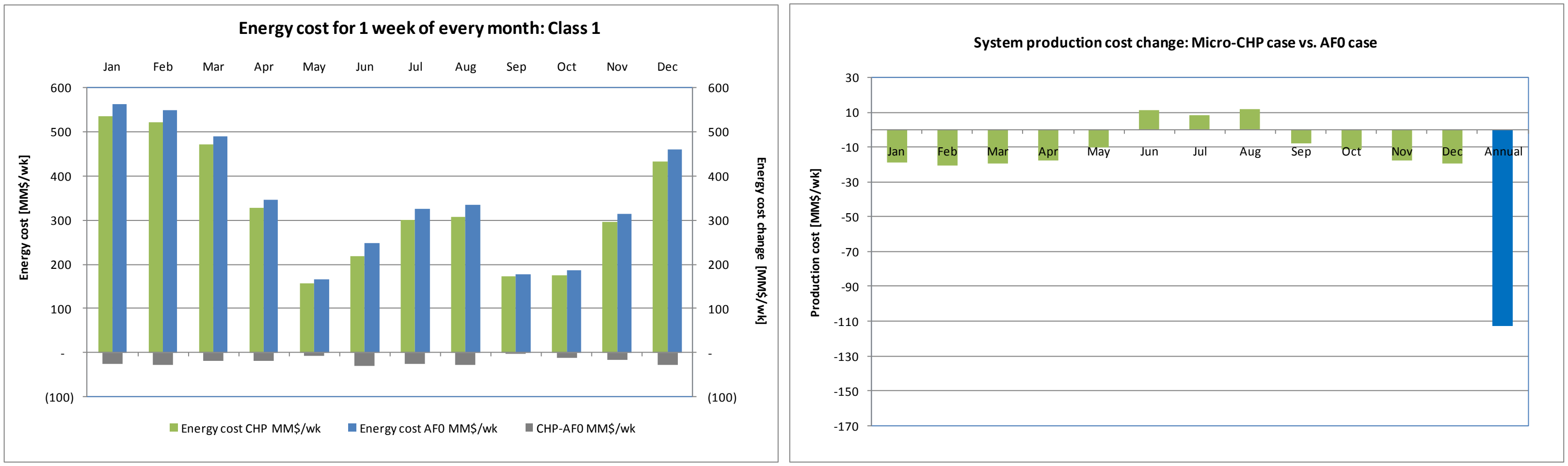


Figure 6.2.19: Comparative results for micro-CHP vs. no micro-CHP cases – Customer Class C1's energy cost Total & Change per month

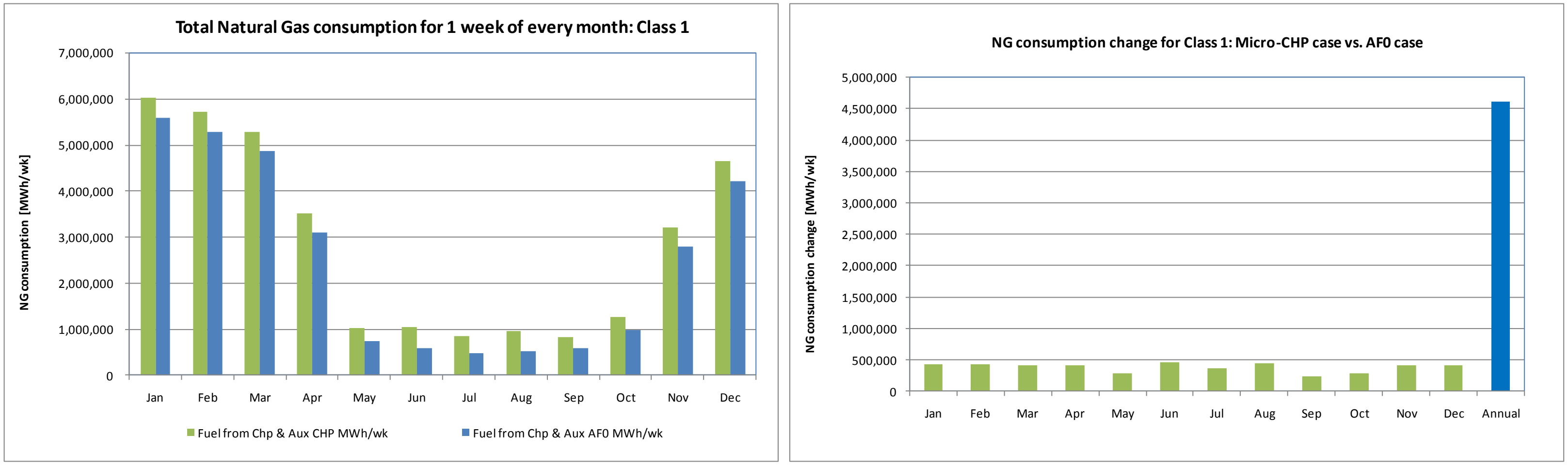


Figure 6.2.20: Comparative results for micro-CHP vs. no micro-CHP cases – Customer Class C1's NG consumption Total & Change per month

As mentioned in the previous section of results at the system-level, the micro-CHP's operational pattern changes according to the retail price level that end-customers receive. In the case of including network & capacity payments costs in the form of energy charges (*CHP case* just described above), the operation of micro-CHPs and the system in general is inefficient, *increasing the productions costs of the energy system*. *At residential level, we observe the negative effects for the system with increasing levels of excess heat, worse efficiency and more CO2 emissions.*

Again, we looked at the results of the baseline CHP case (*CHP case*) and the modified CHP case without NC & GCP (*CHP w/o NC&GCP case*), but at the residential level. We observed the following effects for customer class C1 (similar trends were found for customer class C2):

- Since micro-CHP heat waste is dramatically reduced, residential CO2 emissions decrease and energy efficiency improves during summer months (see June, July, and August in Figure 6.2.21, Figure 6.2.22).

- Under the modified CHP case, micro-CHPs are used more efficiently and residential energy costs decrease all year round including summer season (see June, July, and August in Figure 6.2.23). We also observe that the cost reduction at the residential level is much lower in the *CHP w/o NC&GCP case,* as savings for those additional charges are not considered in this particular case.

Finally, the aggregated results for each customer class for the case without NC & GCP charges are summarized in Table 6.2-6:

Annual effects with 10% micro-CHP HPR2.7 penetration	**Residential metrics for C1**	**Residential metrics for C2**
CO2 emissions	~ 6.3% reduction	~ 7.3% reduction
Energy efficiency[175]	~ 7.5% increment	~ 8.0% increment
Energy cost	~ 2.2% reduction	~ 2.5% reduction
NG consumption	~ 12.9% increment	~ 15.7% increment
Summer micro-CHP excess heat	~ 0.2% summer	~ 0.06% summer
Contribution to electric demand	34% annual	32%
Contribution to heat demand	30% annual	37%

Table 6.2-6: Summary of annual effects per customer class with large-scale penetration of micro-CHPs

[175] Values are expressed as percentage change.

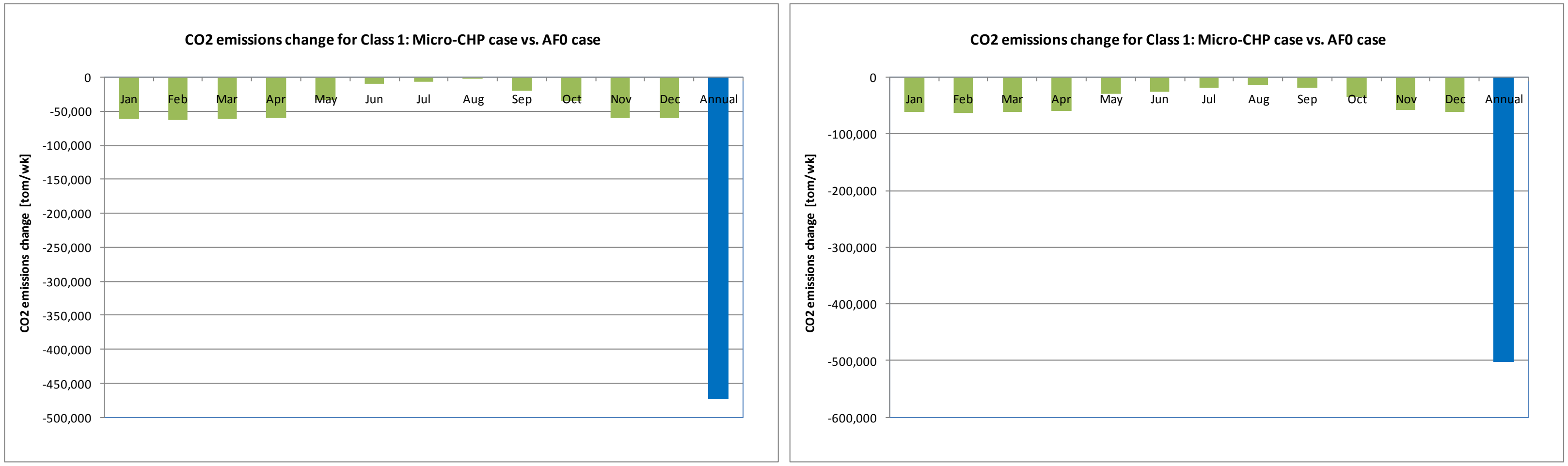


Figure 6.2.21: Customer class C1 CO2 emissions - CHP case &. CHP without NC&GCP case vs. AF0 case

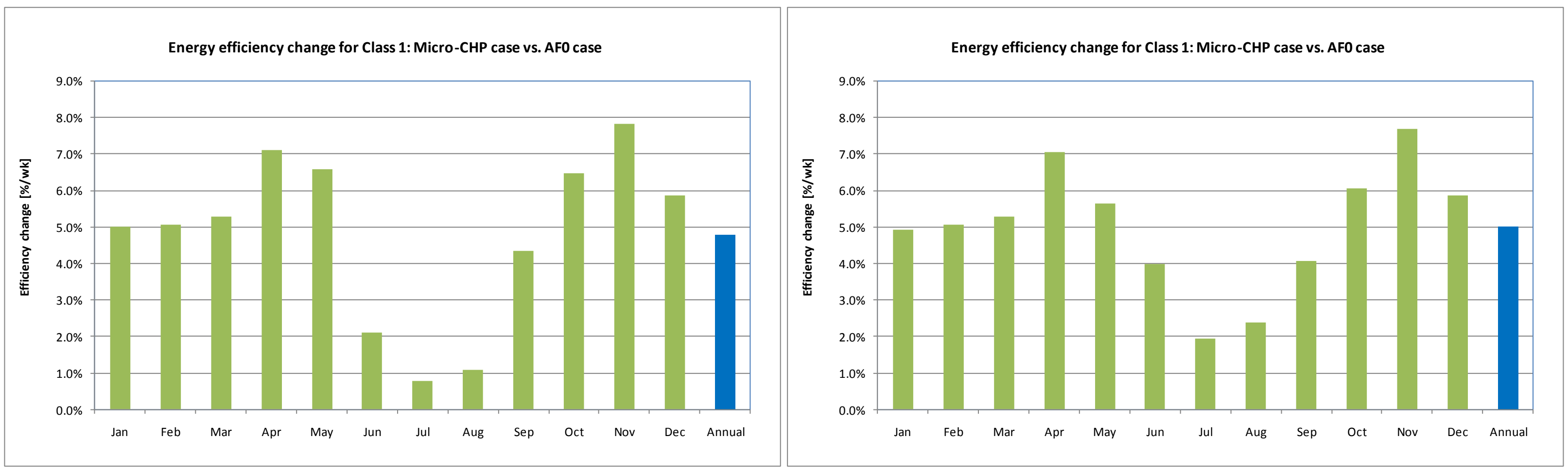
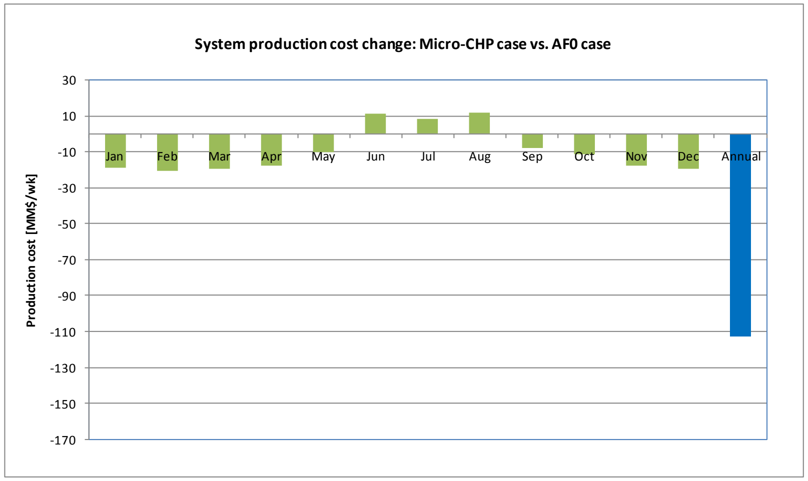


Figure 6.2.22: Customer class C1 energy efficiency (percentage points) - CHP case & CHP without NC&GCP case vs. AF0 case



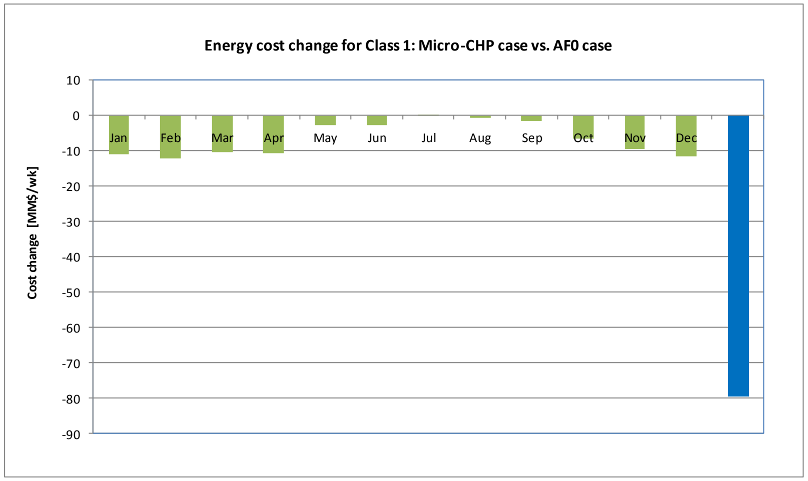


Figure 6.2.23: Customer class C1 energy costs - CHP case & CHP without NC&GCP case vs. AF0 case

In Appendix C.14 we have included a sample set of results for 1 particular month – February/Winter. We need to recall that the ST model was done for one week of every month of the year, but in the appendixes we only include 1 out of 12 simulation outcomes per case.

6.2.3. Sensitivity analysis to retail rates

This section explores how sensitive the operation of a large number of micro-CHPs is to different electricity retail rates passed to customers owning this technology. Based on three electricity retail pricing schemed (hourly, flat, and time-of-use rates) we look at the operation of micro-CHPs and their impact on the overall electricity system production costs.

6.2.3.1. Methodology

Here we use a methodology similar to that used by electric system operators in the day to day operation. Generally speaking, first we determine the day-ahead energy market conditions - i.e. electric load and short-run marginal prices. Second, we determine the conditions for each operating day in the system according to the actual load requirements after the final response of micro-CHPs to the retail electricity prices. The following diagram illustrates this:

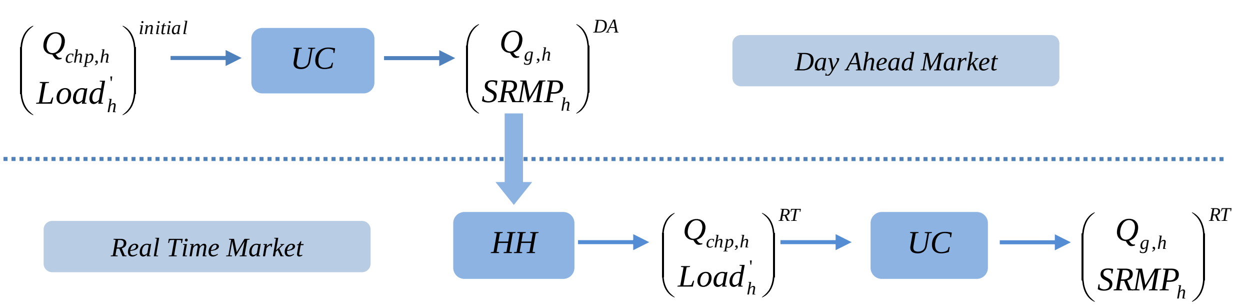


Figure C. 1: Methodology used for passing electricity prices to residential customers

The same methodology is applied for the three electricity rates under analysis. The only difference is the way prices are passed onto final customers:

- *Hourly rate* is based on the short-run marginal prices calculated in the day-ahead market (*SRMP*). These hourly prices are passed the next day to final customers who operate their micro-CHPs according to these signals. A residential household model (*HH*) is used to get the total electric production from micro-CHPs (*Qchp*) that is later used to estimate the residual system's load for the day (*Load'*). Then, a unit commitment model (*UC*) calculates the final production for conventional generators (*Qg*) and the final hourly prices for the real time market.

- *Flat rate* is also based on the day-ahead SRMPs. However, in this case the DA prices passed to customers for next day's operation are flat prices, based on the load weighted average of the 24 SRMPs of the day. Therefore, the same price is given every hour of the day for customers who decide the micro-CHP operation according to these price signals.

- Similarly to flat rate, *time-of-use rate* is based on the day-ahead SRMPs with the difference that, in this case, the DA prices passed to customers for next day's operation are flat prices for peak and off-peak hours. Thus, for summer season, we estimate a peak rate based on the load weighted average of the SRMPs for the peak hours of the day (11am to 22pm for weekdays), and an off-peak rate for the other hours of the day.

In Figure 6.2.24 we show the electricity retail rates being calculated for one particular week in summer. Similarly, for the other summer weeks we estimated the different retail rates to be passed to final customers.

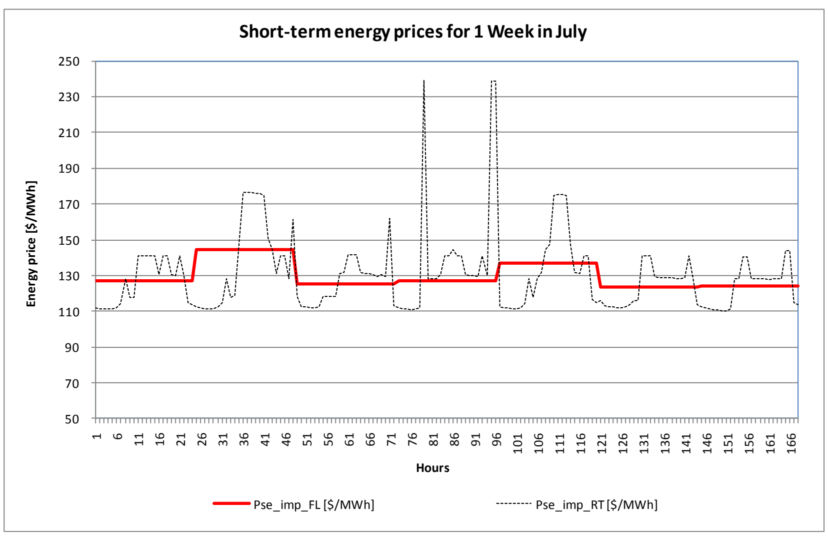


Figure 6.2.24: Electricity retail rates - Sample for 1 week in July

6.2.3.2. Analysis and results

To show the effects of different retail pricing schemes on micro-CHP operation, we focus the analysis on summer months. In general we see that micro-CHP technology is not very sensitive to electricity prices, in particular for those technologies with high heat-to-power ratio (HPR).

Recalling what we observed in Chapter 4, we noted that the operation output of micro-CHPs capable to react to energy price signals changes depending on the load (electricity & heat) and electricity price conditions. Figure 6.2.25 shows the possible micro-CHP operational outputs[176]:

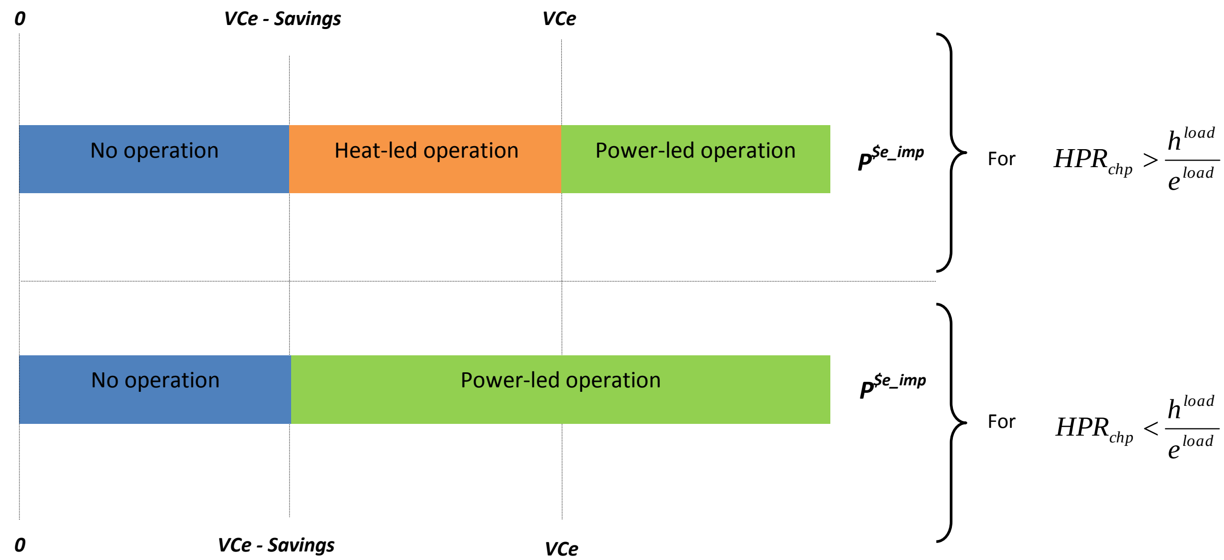


Figure 6.2.25: Micro-CHP operational outputs under different prices & load conditions

From here we see that, depending on the load conditions, the operation of micro-CHPs will change whether the electricity retail price is or isn't within their variable cost range. This range is given by the electric-only variable cost (*VCe*) and the variable cost considering the savings from producing heat simultaneously (*VCe-Savings*). These components are given by the following expressions:

$$VCe = \left(f_{chp} \times hr_{chp}^{elec} + vom_{chp} + p^{co2} \times ef_{chp} \times hr_{dms}^{elec} \right)$$

$$Savings = HPR_{chp} \times \left(f_{aux} \times hr_{aux}^{heat} + vom_{aux} + p^{co2} \times ef_{aux} \times hr_{dms}^{heat} \right)$$

For example, for high heat load conditions like in winter, most of the time we see that the ratio between heat and electric load will be higher than the micro-CHP heat-to-power ratio, i.e. $\left(HPR_{chp} \leq \frac{h^{load}}{e^{load}} \right)$. Thus, if the retail electricity price is above (*VCe-Savings*), the machine will follow the electric load. On the other hand, for low heat load conditions and high electric load like in summer, we see that $\left(HPR_{chp} \geq \frac{h^{load}}{e^{load}} \right)$ particularly during peak hours, and for micro-CHPs with low or

[176] These results are for the case of not having a buy-back rate. For details on this, refer to Chapter 4.

medium HPR. In this case, if the retail electricity price falls between $(VC_e - Savings, VC_e)$ the machine will follow the heat load. But if the price is above (VC_e) the machine will follow the electric load[177].

Under the particular price conditions for the year under analysis (year t20), the variables costs for micro-CHP technologies are (see Table 6.2-7):

Micro-CHP technologies year t20	VCe [$/kWhe]	VCe-Savings [$/kWhe]
Micro-CHP0.6	0.158	0.108
Micro-CHP2.7	0.325	0.096
Micro-CHP7.0	0.720	0.129

Table 6.2-7: Micro-CHP electricity-only variable costs (VCe) and with savings for producing heat (VCe-Savings)

As we can see, this price range is quite large for micro-CHP technologies with medium and high HPR. Therefore, if the retail electricity price given to residential customers is between these ranges, the micro-CHP operation will be the same even if the rate is hourly, flat or time-of-use. For example, if the electricity prices are those shown in Figure 6.2.24, we see that:

- For Monday the hourly SRMPs fall between 0.110-0.140[$/kWh] and the flat rate is about 0.135[$/kWh]. Under these conditions the operation of micro-CHP will be the same for the hourly and flat rates for a micro-CHP with HPR0.6 and HPR2.7.

- For Friday the hourly SRMPs fall between 0.110-0.180[$/kWh], with a flat average of about 0.140[$/kWh]. According to the variable cost range, a micro-CHP with HPR0.6 would have a different operation for a flat rate or an hourly rate[178]. However, a micro-CHP with HPR2.7 would not vary its operation.

[177] In either load condition cases, if the electricity price is below (VCe-Savings) the consumer would prefer to buy all from the grid, i.e. not operate the micro-CHP.
[178] The micro-CHP HPR7.0 technology is not considered in these analyses as we saw that is not a competitive technology when compared to the other two. However, it is worthwhile to note that when the electricity price is low, it gives no incentive for this technology to operate. Thus, this technology could have different operation if consumers receive flat or hourly rate.

For illustration purposes only, in the following figures we show the micro-CHP operation with HPR2.7 and HPR0.6 under hourly and flat electricity rates. This simple example is done for one customer, one day in summer, with micro-CHPs with enough electric capacity to cover peak demand:

- In Figure 6.2.26 and Figure 6.2.27 we see the operation of a micro-CHP HPR2.7 under hourly and flat rate respectively, and its contribution to meet the residential electric and heat load during 1 day in summer. In this case we have that $\left(HPR_{chp} \geq \frac{h^{load}}{e^{load}} \right)$ in every hour of the day. In both rate cases we see that the electricity prices are between $\left(VC_e - Savings, VC_e \right)$. Thus, according to these conditions, the micro-CHP follows the heat load under both pricing schemes.

- In Figure 6.2.28 and Figure 6.2.29 we see the operation of a micro-CHP HPR0.6 under hourly & flat rate, and its contribution to meet the residential electric and heat load during 1 day in summer. In this case we have that $\left(HPR_{chp} \geq \frac{h^{load}}{e^{load}} \right)$ and SRMP prices are above *VCe* during peak hours. Therefore, for the hourly pricing scheme, micro-CHP follows the power load regardless of the heat load level. In fact, we observe that some of the produced heat is not used on-site and it is expelled into the atmosphere (see orange area in Figure 6.2.29). For the flat rate case, we note that flat prices are between $\left(VC_e - Savings, VC_e \right)$. Thus the micro-CHP operation differs from the hourly rate case as in the flat case micro-CHPs follow the heat load. Now there is no excess heat and users need to buy additional electricity to meet total power load.

According to what we have explained, in this section we will focus the analyses on a particular week in summer and for a micro-CHP with low HPR. *It is under this scenario that we expect to see most of the micro-CHP operational patterns variations when subjected to varied electricity retail pricing schemes.*

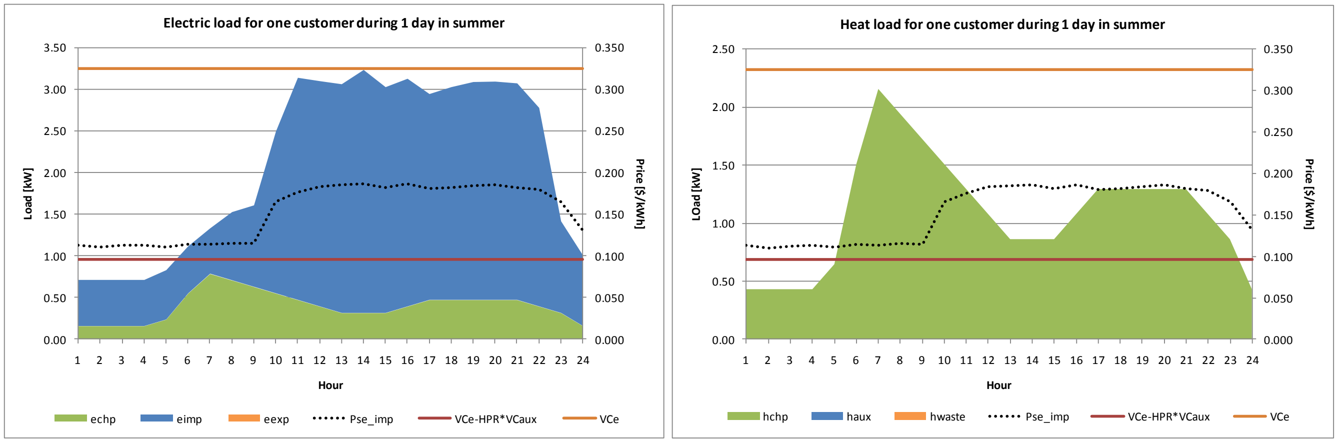


Figure 6.2.26: Micro-CHP operation with HPR2.7 for one customer, 1 day in summer under hourly (HR) rate

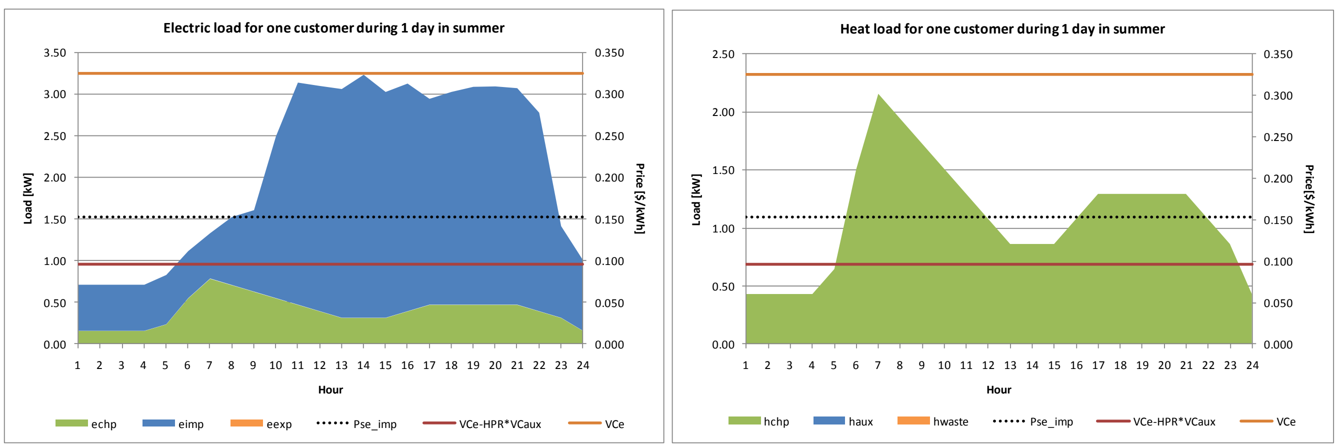


Figure 6.2.27: Micro-CHP operation with HPR2.7 for one customer, 1 day in summer under flat (FL) rate

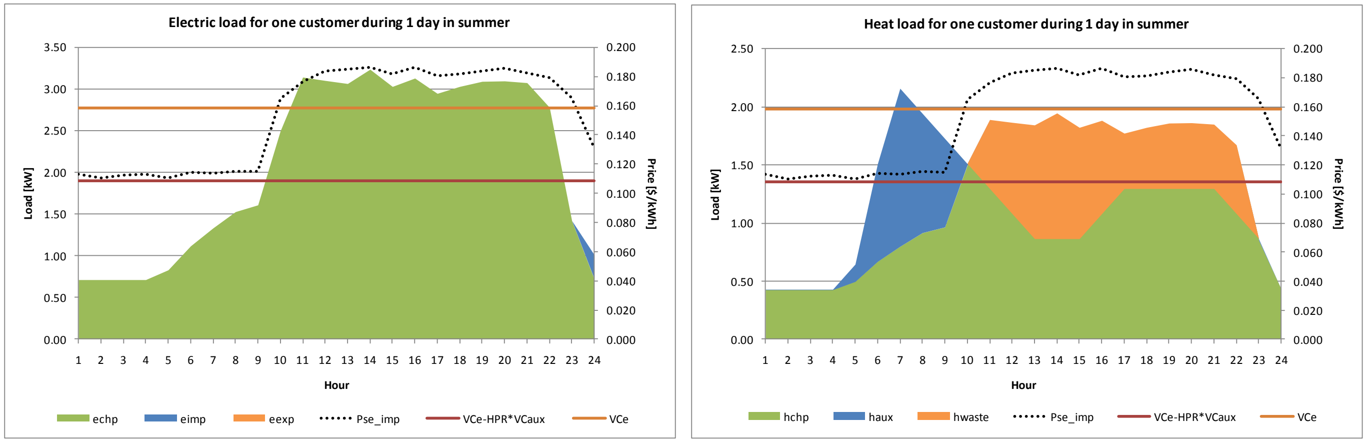


Figure 6.2.28: Micro-CHP operation with HPR0.6 for one customer, 1 day in summer under hourly (HR) rate

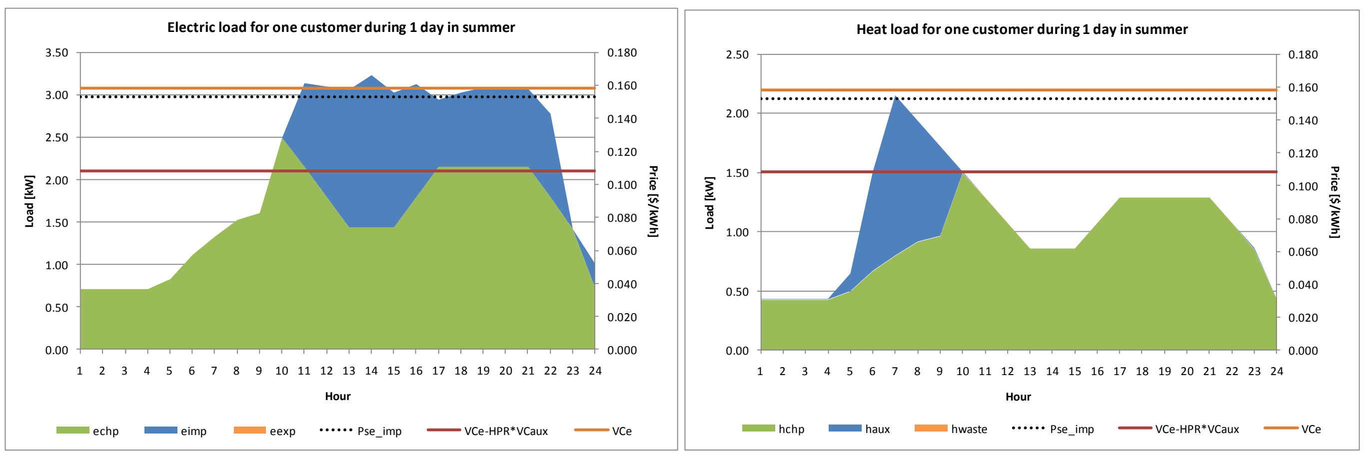


Figure 6.2.29: Micro-CHP operation with HPR0.6 for one customer, 1 day in summer under flat (FL) rate

Results for summer season

Results show that, mostly during summer, the operation of micro-CHPs differs when residential customers are subjected to different electricity retail rates. In general we note that the *system's energy production costs* are higher with a flat rate than with an hourly rate, and the electric production of micro-CHPs increases a bit. However, as we explained above, the cost increment and production variations are quite small because of the characteristics of the micro-CHP technology, and its sensitivity to energy prices and energy load conditions.

Looking at the results, we also note that the size of the micro-CHP units has certain impact on the outcomes. In particular, if the size is the relatively small, we observe the same micro-CHP operation under different rates as the operation would be limited by the size of the machine. For example, in the case of a micro-CHP HPR0.6 with an electric size is 1.8kWe and heat output of only about 1kWth, the operation is as follows:

- Under a flat rate, the micro-CHP tends to follow the heat load. The machine operates at maximum capacity since heat is bit larger than 1 kWth during summer in the evenings.

- Under an hourly rate, the micro-CHP tends to follow the electric load. The machine again operates at maximum capacity since the electric load is much higher than 1kWe during summer in the evenings

If the micro-CHP unit size were larger, the operation would not be limited by the size of the unit. Under an hourly rate, the micro-CHP could be able follow the electric load and we could see a different operation than under a flat rate. The impact of micro-CHP unit size can be more clearly seen in Figure 6.2.28 and Figure 6.2.29 shown above. *Taking into account this, we also worked on a case where the size of the micro-CHP units is larger and not necessarily optimum to the customers' size*[179].

In summary, to show the effects of having different electricity retail pricing schemes, we worked on two new cases[180] with the following main modifications:

- Micro-CHP technology with HPR0.6 instead of HPR2.7. As its variable costs range is narrower than that for micro-CHPs HPR2.7, we expect to have more operational variations with micro-CHPs HPR0.6 and to see greater impacts on the system's productions costs under varied electricity retail rates.

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[179] Recall that the optimum micro-CHP unit size was obtained through a simplified payback analysis. For the case micro-CHP with HPR0.6, the optimum size for customer class C1 was 1.8kWe and for customer class C2 was 3.2kWe.

[180] These cases are different from the cases of the previous section which showed the effects of having a large penetration of micro-CHPs within an energy system when compared to the scenario of not having this technology.

- For the case of adopting micro-CHP HPR0.6, the optimum unit size for customer classes C1 and C2 is 1.8kWe and 3.2kWe respectively. For the alternative case where users adopt bigger units, we assumed micro-CHPs of 4kWe for both classes of customers.

- Accordingly, the number of users within each customer class is adjusted considering the micro-CHP unit size assumed in each case and the system electric capacity. For the optimum case, the number of users is 953,367 and 483,994 for C2 & C2 respectively. For the alternative case, the number of users is 429,015 and 387,195 for C2 & C2 respectively.

- The simulations and analyses are focused during summer, as energy price conditions and energy load conditions seem to favor a more varied micro-CHP operational pattern when subjected to different retail rates.

- Both cases include fixed operational costs of conventional electric power plants, such as start-up costs. However, we have not included in the simulation neither network costs nor generation capacity payments with the purpose of not distorting the outcomes.

Finally, Table 6.2-8 shows the results for one month during summer (August), where "+" sign indicates an increase of the metric in the Flat case (FL) with respect to the Hourly case (HR):

Comparative results *(FL-HR)/HR*	**Case Optimum** *FL vs. HR*	**Case Alternative** *FL vs. HR*
System production cost	+ 0.02%	+ 0.17%
System micro-CHP electric production	+ 0.42%	- 3.86%
Residential energy cost C1	+ 0.01%	+ 1.89%
Residential energy cost C2	+ 0.07%	+ 0.96%

Table 6.2-8: Comparative results for 1 month during summer - Flat rate vs. Hourly rate cases.

From this, we see that a *Flat rate increases the energy production costs for both the system and each residential customer class*. In the case with optimum micro-CHP unit size, we see that the electric production does not change substantially between the Hourly case (HR) and the Flat case (FL). Under this scenario, the costs increments are very small. However, in the case where we assume a much larger unit size we see a different micro-CHP production pattern and a bit more significant cost increase in the flat rate case[181].

[181] The case of time-of-use rate has been left for future research.

6.2.4. Summary

In this section we studied the short-term operational impacts of a wide-scale deployment of micro-CHPs within a particular energy system. Based on quantitative metrics, such as energy productions costs, CO2 emissions, energy efficiency and peak load reduction, we used a short-term operational model that simulated the operation of an electric system integrated with the operation of a large number of micro-CHPs at the residential level.

In the first part of the analysis, we focused on the comparative effects of having a large number of micro-CHPs against the case of not having them as part of the energy portfolio. Results showed that:

- The operation of micro-CHP brings positive effects, such as CO2 emissions reductions, energy efficiency improvements, systems' energy production costs decrease, and summer peak load reduction at both system and residential levels.

- The operation of a large number of micro-CHPs increases considerably on-site natural gas fuel consumption all year round at residential level.

- Seasonal variations are also important. During winter, micro-CHP's capacity factor is quite high and most of the positive effects occur during this season as both electricity and heat are fully used by residential customers. In summer, micro-CHP's production seems more volatile and more dependent on the electricity prices sent to end-users. Thus its effects will depend on the energy price signals consumers receive, as well as energy load conditions.

- Micro-CHPs compete mostly with Gas Combined Cycles, with some generation increment from Gas Combustion Turbines in particular during summer when micro-CHP production is low.

In the second part, we looked at the micro-CHP's sensitivity to varied electricity retail pricing schemes. Results showed that:

- Micro-CHP technology is not very sensitive to electricity prices, in particular for those technologies with very high heat-to-power ratio (HPR). Depending on the load conditions, the micro-CHP operation will change depending on whether the electricity retail price is within the machine's variable cost range. This range is given by the micro-CHP's electric-only variable cost (VCe) and its variable cost considering those savings from producing heat simultaneously (VCe-Savings).

- Most of the micro-CHP operational patterns variations occur for a technology with low HPR, and during summer when electricity retail prices are higher and heat load requirements lower.

- A flat rate increases energy production costs for the system and residential customers (when compared to an hourly rate). However, these cost increments and production variations are quite small because of the particular micro-CHP technology's characteristics, and its sensitivity to energy prices and energy load conditions.

In addition, we looked at how micro-CHP's operational patterns change in response to electricity price signals intended to give the appropriate incentives to efficiently operate within an energy system. We observed that:

- Additional energy charges included in the retail price, like network and capacity payment costs, considerably increase the prices received by end-users during peak times in summer. As a consequence, users have an incentive to produce electricity using micro-CHPs instead of buying it to the grid. Micro-CHP's production is quite high as the units try to cover electric load requirement regardless of the low heat load. This micro-CHP production pattern comes at the expense of increasing the system's production costs, growing excess heat during summer, and deterioration of the efficiency in the system.

- When prices reflect variable operational costs only, micro-CHPs production is low but enough to try to cover summer heat requirements. The operation of the micro-CHPs is more efficient and with no excess heat.

CHAPTER 7

CONCLUSIONS

7.1. Summary and contributions

This thesis introduces a methodology to assess the contribution of a large-scale penetration of distributed generation towards using existing resources more effectively and improving the energy conditions in the near and long terms. Micro-CHP or the co-generation of electricity and heat at the residential level is chosen because of its potential for enhancing energy efficiency and reducing GHG emissions, improving the utilization of primary energy sources.

The general approach throughout this thesis is first, to define an energy system without the presence of micro-CHPs and second, to formulate the same system with significant amounts of micro-CHPs at the residential level. Then, the value of micro-CHPs is assessed considering varied system-wide and residential metrics, considering the evolution of the energy system in the long-term and the operation of the system for the last year of the timeframe. In particular, the contributions of this thesis are:

- The development of a methodology that focuses on integrating a large number of micro-CHPs into an electric system's generation capacity expansion process, and integrating the daily operation of electric power plants with a significant volume of micro-CHPs on the customer's side. This methodology explicitly includes energy demand in the form of electricity and heat, incorporating large amounts micro-CHPs able to simultaneously produce on-site electricity and heat, and looking at the system's optimal decisions while reacting to varied energy price signals.
- A quantitative assessment of the value of micro-CHPs not only to residential customers, but also to the overall energy system, with the purpose of understanding whether this technology is a valuable contribution to social welfare. This thesis explores the effects of a large-scale penetration of micro-CHPs in terms of efficiency, CO2 emissions, peak load reductions, and energy costs.
- A better understanding of the conditions that may encourage a larger penetration of micro-CHPs, the role of economic signals and a more transparent information on the operation of micro-CHPs, and the complexities that a widespread penetration of this technology brings to energy systems.

This research aims at informing policymakers and regulators on the contributions of micro-CHPs as one more helpful measure in a carbon constrained world. The findings of this thesis are discussed below, along with future research directions.

7.2. Findings and discussion

We observed that when micro-CHPs are analyzed from the customer-only perspective, it is clear what the costs, efficiency and environmental benefits are. However, when this technology is analyzed in a broader context - particularly under a large deployment and from the energy system regulator's point of view – the benefits may be less apparent, as now they need to include the overall impact on the system.

7.2.1. Long-term effects

In order to have an important amount of micro-CHPs over a period of time, we found that it is required to have certain economic conditions to favor such penetration. We looked into varied investment cost, natural gas retail price and carbon price conditions to understand their impact on future micro-CHP penetration within an energy system (refer to Chapter 6 for details). Results showed that:

- Lower micro-CHP capital cost and lower natural gas retail price for residential customers increase the penetration of micro-CHPs. High capital costs or high gas retail prices make the technology uncompetitive, leaving micro-CHP out of the energy portfolio with the system preferring conventional heating units for the supply of heat requirements, despite the system efficiency advantage of micro-CHPs.
- Higher CO2 price seems to favor the development of micro-CHPs. However, further research is required to better understand the competition of micro-CHP with cleaner electric power technologies.

The long-term effects of having a micro-CHP penetration of 10% of the total electric installed capacity at the end of the 20-year timeframe included:

- Cumulative CO2 emissions reduction over the 20-year time period. For scenarios with medium to high CO2 price, the reduction was between 4%-5% of the total emissions in the energy system, with respect to a scenario without micro-CHP.
- Displaced installed capacity from gas-based technologies. For high to medium carbon price scenarios, micro-CHPs displaced mostly natural gas combined cycle units.

We see that micro-CHPs help to reduce cumulative CO2 emissions, where a larger penetration could be encouraged through economic incentives such as micro-CHPs capital costs reduction, and/or lower micro-CHP production costs. However, if a larger penetration is promoted, it is required to further understand the impacts of the direct competition of micro-CHPs with gas-based technologies, such as its potential impact on the power system operating reserves. For example, we noted that the decline of generating capability by gas combined cycles impacted the operation of the system. During summer, sometimes the system required additional operation of gas combustion turbines because of the low micro-CHP electric production and the lack of additional gas combined cycle units to supply peak demand.

In addition we observed that, under varied market conditions, conventional heating and micro-CHP technologies compete among themselves to supply residential heat requirements depending on outputs characteristics. Results showed that:

- For high micro-CHP costs or fuel price, the energy system prefers conventional heating units to micro-CHPs to supply heat. Conventional systems are more competitive than micro-CHP technologies, since on-site production of electricity is not cost-effective for residential customers.
- As the costs of micro-CHPs or fuel price decrease, the energy system chooses a combination of micro-CHPs with medium heat-to-power ratio (HPR) and conventional heating systems to supply residential heat requirements.
- For low micro-CHP costs or fuel price, the system clearly favors the deployment of low HPR micro-CHPs in combination with conventional heating systems.

Clearly, economic conditions may favor one micro-CHP technology over another, but micro-CHPs with very high HPR do not seem a competitive alternative. This type of technology generates very little electricity per every unit of produced heat, so the savings from electricity are marginal when compared to other micro-CHP technologies. Moreover, the cost of producing heat-only is more expensive than with conventional heating units. Regarding micro-CHPs with low HPR, better economic conditions, such as low capital cost or fuel price, favor the deployment of this alternative. As this technology is able to produce more electricity per unit of heat, it becomes competitive in electricity production.

Although these findings provide information on the energy system's technology of choice from an economic point of view, additional research is required in order to understand their competitiveness under varied residential energy load conditions, a different electric energy portfolio, and a different regulatory structure that may impact the value of the electricity being produced by micro-CHPs.

7.2.2. Short-term effects

Results of an individual analysis, from a customer-only point of view, showed that micro-CHPs bring benefits compared to the traditional model of buying electricity from the grid and producing heat separately (see Chapter 3). In particular, we observed energy cost savings, energy efficiency improvements and CO2 emissions reductions, with the most positive contributions during winter.

We also found that these benefits can increase with the incorporation of additional features such as a hot water storage unit integrated to the heating system, micro-CHP modulating capability, and a micro-CHP price-based control strategy (see Chapter 4):

- The heat storage unit gives the micro-CHP system more flexibility in meeting local thermal demands, and there is a more efficient use of the produced heat by micro-CHPs. The increments in benefits are more perceptible for those technologies able to produce more heat per every unit of electricity.

- A continuous micro-CHP electric output, as opposed to a discrete one, allows the micro-CHP to operate more closely to the energy load, increasing the micro-CHP capacity factor and minimizing any excess of heat.
- An intelligent price-based control strategy, as opposed to a heat-led operation, allows the micro-CHP unit to respond to electricity prices and load conditions. Under this strategy, the operation is optimum from the economic point of view and, depending on the technology and price signals, it can also result in additional CO_2 emissions reductions and efficiency.

Although micro-CHP is still an immature technology, with very high capital costs, a major cost reduction is expected if production volumes increase. These potential lower costs, along with the above mentioned positive operational results, may make micro-CHPs more appealing for potential new customers seeking to buy or upgrade their heating systems.

Results from the short-term analysis, derived from the operation of the energy system during one particular year, showed that a widespread operation of micro-CHPs also results in positive effects such as CO_2 emissions reductions, energy efficiency improvements, lower systems' energy production costs, and summer peak load reduction at both system and residential levels. For the case of having an optimally adapted electric system to an important volume of micro-CHPs, i.e. 10% of total electric capacity by year 20, we looked into the operation of the system. Comparative annual results with respect to the case without micro-CHP showed (refer to Chapter 6 for details):

- CO_2 emissions reduction of about 5% for the energy system, and between 6% and 7% for residential customers.
- Energy efficiency improvements of about 3.5% for the energy system, and between 7% - 8% for residential customers.
- Operation production costs reduction of about 1.4% - 2% for the system, and energy costs savings between 2.5% - 6.5% for residential customers.
- Peak electric demand reduction of about 10% - 15% during summer, even when the operation of micro-CHPs drops during this season.
- On-site natural gas consumption increment of over 10% for residential customers.

In addition, we examined seasonal variations. During winter, the micro-CHP's capacity factor is quite high and most of the positive effects occur during this season as both electricity and heat are fully used by residential customers. Also, the electricity produced by micro-CHPs displaces mostly gas combined cycle generation all year round, while generation from combustion turbine units and coal plants increases somewhat during summer. This effect is the consequence of a lower micro-CHP capacity factor, and the lack of cheaper resources - such as combined cycle units - to produce power during these peak hours.

Finally, the benefits found at system level seem to be relatively low for the high penetration level of micro-CHPs. Moreover, the operation of a large number of these units increases considerably on-site natural gas fuel consumption all year round. To support this important volume of micro-CHPs, it is required to have an adequate natural gas infrastructure in place. Also, additional research is required to better understand the impact of having increasing levels of on-site emissions in residential areas, as opposed to distant sources of emissions.

7.2.3. The role of electricity prices

This thesis assumed a price-based control strategy for micro-CHPs, where users operate their micro-CHPs if it is more cost-effective to turn the machine on than buying electricity and fuel separately from the local utility. We found that micro-CHPs can react in different ways depending on the electricity prices passed to residential customers, as well as the energy load conditions, and the micro-CHP technology itself.

First we looked into the sensitivity of micro-CHPs to varied electricity retail pricing schemes (see Chapter 6). Results showed that:

- When compared to an hourly rate, a flat rate increases energy production costs for the system and residential customers. Because of the particular micro-CHP technology characteristics, energy prices and energy load conditions; the cost increments and production variations are small. However, most of the differences occur for a micro-CHP technology with low HPR and during summer, when electricity retail prices are higher and heat load requirements are lower.

- Micro-CHP technology is not very sensitive to electricity prices. Depending on the load conditions, the micro-CHP operation changes depending on whether the electricity retail price is within the machine's variable cost range given by its electric-only variable cost and its variable cost considering the savings from producing heat. In the particular case of technologies with medium to high heat-to-power ratio, this cost range is quite large and the micro-CHP response is similar for either tariff rate, especially in an electric system with smooth marginal prices. In the case of micro-CHPs with low HPR, they seem more sensitive to prices and they tend to operate following the electric load with the purpose of avoiding expensive electricity from the grid.

A better tariff design improves the economic efficiency of the system. It is able to better reflect the system conditions, and allows users to decide the most efficient operation of their micro-CHPs. However, the improvements are small as the technology may not be very sensitive to electricity prices. Therefore, depending on the technology and marginal prices, a well designed time-differentiated tariff rate may result in similar on-site generation response as with an hourly retail rate, although further research is required.

Then, we looked into the operational and costs effects of incorporating additional charges into the retail price (see Chapter 6). We observed that:

- Network and capacity payment costs, included as energy charges in the retail price, considerably increase the price received by end-users during peak times. The consequence is high micro-CHP production at times when the heat load is low, as users prefer to produce electricity and avoid buying expensive electricity to the grid. This production pattern comes at the expense of increasing the system's production costs, growing excess heat during summer, and deterioration of the efficiency in the system.

Clearly, appropriate electricity price signals encourage an efficient operation of micro-CHPs within the energy system. When the price signal sent to micro-CHPs reflects the system's short-term marginal price, the operation of the micro-CHPs is more efficient and with no excess of heat at times of low heat demand. Therefore, it is necessary to implement a tariff structure that gives the right economic signals to micro-CHP customers, in order to make an efficient use of the service while recovering the total network and reflecting the electricity production costs or market prices.

Finally, we briefly looked into the effects of having buy-back rates for potential excess of electricity (see Chapter 4). Results from a consumer-only perspective showed that:

- Buy-back rate may distort the economic efficiency of the energy system, resulting in an inefficient operation of micro-CHPs and electric power units. When the rate is high, the production of electricity by micro-CHP becomes very attractive to residential customers because of the potential revenues for the sale of electricity, regardless of the local heat requirements.

A production subsidy in the form of a buy-back rate impacts the operation of micro-CHPs which, depending on its value, may distort the short-term marginal price signal. Micro-CHPs may favor electricity-only production, resulting in increased costs, increased excess heat, and decreased efficiency. Additional research is required to better understand these effects in an energy system with large amounts of micro-CHPs.

The inclusion in this thesis of micro-CHP's response to energy price signals helped to better understand the operation of this technology to electricity retail prices and buy-back rates. Therefore, it is assumed that consumers have some form of metering system able to register consumption levels and generation of electricity, as well as a communication system that allows consumers to get information about the system. We see that more accurate information requires a more sophisticated and expensive metering infrastructure. However, this infrastructure would make possible a better tariff design, increasing the economic efficiency of the energy system. We did not investigate the particular measurement, control and communications systems required to support the response of an important volume of micro-CHPs.

7.3. Future research

We have classed the further areas of research as improvements to the methodology and applications of other areas of interest.

7.3.1. Areas of improvement

In Section 5.2 we explained the long-term capacity expansion model used to derive the energy portfolio of a system that has been adapting to increasing levels of micro-CHPs during a timeframe of 20 years. The electric energy portfolio used in the model at the beginning of the time period considered a mix of fossil fueled power plants and nuclear power plants, similar to what can be found in the New England region. Renewable energy sources were not included because of the difficulty in estimating their future share in the resource mix. However, given the wind resource potential in the region and the interest of policy makers, it is reasonable to believe a larger participation of these resources. Therefore, the incorporation of renewables into the model energy portfolio should help to further understand the effects of micro-CHPs and assess their environmental benefits in this new scenario.

In Chapter 5 we introduced the concept of class of customers and the methodology used to integrate residential-level results into the operation of the electric power system:

- A customer class is a simplification used to recognize different residential energy loads within the energy system. These classes combine a large number of the same type of residential customers, characterized by their simulated electric and heat load profiles. In this work, we included only two types of residential customers located in a Boston-like area. Therefore, although the model run-time increases with the number of classes, it is advised to include more classes of customers in order to get a more diverse energy system.
- Once defined the customer classes, a micro-CHP technology is assigned to each class, with a size optimum to its particular energy requirements. Using the household model for each class (introduced in Chapter 3), results such as micro-CHP electric production and energy costs are aggregated according to the number of customers in each class. Then, they are integrated with the operation of the electric power system. The methodology used to aggregate results is a very simple approach that could be improved with the purpose of obtaining a smoother micro-CHP response.

Finally, as noted in Section 6.2, the aggregation and the customer class approach, as well as the discrete operation of micro-CHPs, resulted sometimes in an irregular operation of the system in the short-term. As we mentioned above, the operation of micro-CHPs is seen by the electric system as a massive and coordinated response that - depending on load or price conditions - may abruptly change, impacting the operation of the electric system. Ways to smooth simulations results could be achieved by including more classes of customers in order to diversify the residential energy load, including micro-CHP technologies of different sizes and heat-to-power ratios, and adopting a continuous operation of micro-CHPs instead of a discrete one.

7.3.2. Areas for additional research

The methodology developed in this thesis could be used to explore other questions of interest. In particular, understand the suitability and competitiveness of various micro-CHP technologies under different energy load conditions. This research used energy loads based on the profile of residential customers located in a Boston weather-like area. Thus, a region with higher heat requirements could be used for this purpose.

The analyses of the role of electricity energy prices showed that an adequate price signal, such as the short-term marginal price, encourages an economic efficient operation of the energy system. We observed that the incorporation of additional costs in the form of energy charges or buy-back rates for potential electricity surplus may distort the operation of the system. Therefore, an interesting research extension could be to identify the most appropriate electric tariff structure for customers with micro-CHPs, as well as the proper economic value to give to excess of electricity without changing the efficiency of the energy system.

Further research could be done on the coordination and integration of a large number of micro-CHPs into the operation of energy systems. For example, understand their role on the systems short-term reserve margins, as well as the viability for this technology to help at times when the system is constrained, particularly during periods of low heat requirements. Their reserve contribution could be very different depending on the type of technology. A machine with low HPR could be more attractive for the electric system, since it is able to produce more electricity per unit of produced heat and, depending on the unit size, excess of heat could be minimum. Also, a different heating system configuration could increase the contribution of micro-CHPs, where technologies with higher HPR could be also used for reserve purposes. Any surplus of heat could be distributed and used by other customers, instead of dissipating it.

Finally, we observe that this technology lends itself to qualitatively different ways of providing electricity service at value as seen by the customers. In particular, it is very applicable to providing energy in stand-alone micro-grids. New metrics for assessing the impact on distributed reliability and choice for types of energy services will be needed.

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APPENDIX A

HOUSEHOLD MODEL

A.1. Glossary of terms

e_t^{load}	Electric power load during hour t [kWhe]
$h_t^{DHW\_load}$	Domestic hot water load during hour t [kWhth]
$h_t^{SH\_load}$	Space heating load during hour t [kWhth]
$P_t^{\$e\_imp}$	Import electricity price during hour t [$/kWh]
$P_t^{\$e\_\exp}$	Export electricity price during hour t [$/kWh]
$P_t^{\$f}$	Natural gas price during hour t [$/kWh]
η_e^{chp}	CHP electric efficiency [%]
η_{th}^{chp}	CHP thermal efficiency [%]
η_{th}^{aux}	Boiler thermal efficiency [%]
$E^{chp\,i}$	Power output for i possible micro-CHP engine speeds [kWhe]
$H^{chp\,i}$	Heat output for i possible micro-CHP engine speeds [kWhth]
HPR	CHP heat-to-power ratio, constant for operational range [p.u]
H^{aux}	Maximum boiler heat capacity [kWhth]
H^{tank}	Maximum tank heat capacity [kWhth]
e_t^{chp}	CHP power output during hour t [kWhe]
h_t^{chp}	CHP heat output during hour t [kWhth]
h_t^{aux}	Boiler heat output during hour t [kWhth]
h_t^{waste}	Excess heat beyond heat load during hour t [kWhth]
h_t^{in}	Incoming heat to the tank during hour t [kWhth]
h_t^{tank}	Stored heat in the tank during hour t [kWhth]
u	Binary decision variable for micro-CHP to produce 0kWhe
x	Binary decision variable for micro-CHP to produce 1.37kWhe
y	Binary decision variable for micro-CHP to produce 2.37kWhe
z	Binary decision variable for micro-CHP to produce 4.70kWhe

A.2. Retail electricity rates

	Supplier Service (data for 2007)	Delivery Service (data for 2008)						Total	
	Electricity default service* c/kWh	Customer $/month	Distribution c/kWh	Transition c/kWh	Transmission c/kWh	Energy Conservation c/kWh	Renewable Energy c/kWh	***Variable* $/kWh**	***Fixed*** $/month
Jan-07	13.827	4.542	1.257	0.707	0.25	0.25	0.05	**0.16341**	4.542
Feb-07	13.806	4.542	1.257	0.707	0.25	0.25	0.05	**0.16320**	4.542
Mar-07	11.691	4.542	1.257	0.707	0.25	0.25	0.05	**0.14205**	4.542
Apr-07	10.292	4.542	1.257	0.707	0.25	0.25	0.05	**0.12806**	4.542
May-07	9.989	4.542	1.257	0.707	0.25	0.25	0.05	**0.12503**	4.542
Jun-07	10.469	4.542	1.257	0.707	0.25	0.25	0.05	**0.12983**	4.542
Jul-07	10.855	4.542	1.257	0.707	0.25	0.25	0.05	**0.13369**	4.542
Aug-07	11.216	4.542	1.257	0.707	0.25	0.25	0.05	**0.13730**	4.542
Sep-07	9.993	4.542	1.257	0.707	0.25	0.25	0.05	**0.12507**	4.542
Oct-07	10.386	4.542	1.257	0.707	0.25	0.25	0.05	**0.12900**	4.542
Nov-07	10.814	4.542	1.257	0.707	0.25	0.25	0.05	**0.13328**	4.542
Dec-07	11.433	4.542	1.257	0.707	0.25	0.25	0.05	**0.13947**	4.542

Table A- 1: Electricity rates used in the models for Import Electricity Prices - Variable pricing option

Source: NSTAR rates for Boston (http://www.nstaronline.com/ss3/residential/account_services/rates_tariffs/rates/rates.asp)

A.3. Retail gas rates

	Supplier Service (data for 2007)	*Delivery Service (data for 2007)*				*Total*	
	Cost of Gas Adjustment $/therm	Customer $/month	Distribution first 20 therms $/therm	Distribution over 20 therms $/therm	Local Distr. Adjustment Charge $/therm	**Variable first 20 therms** $/kWh	**Fixed** $/month
Jan-07	1.36	10.33	0.5933	0.1469	0.0564	0.0686	10.33
Feb-07	1.2413	10.34	0.5933	0.1469	0.0564	0.0645	10.34
Mar-07	1.2413	10.34	0.5933	0.1469	0.0564	0.0645	10.34
Apr-07	1.2413	10.34	0.5933	0.1469	0.0564	0.0645	10.34
May-07	0.9076	10.34	0.5933	0.1469	0.057	0.0532	10.34
Jun-07	0.9937	10.34	0.5933	0.1469	0.057	0.0561	10.34
Jul-07	0.9937	10.34	0.5933	0.1469	0.057	0.0561	10.34
Aug-07	0.9937	10.34	0.5933	0.1469	0.057	0.0561	10.34
Sep-07	0.9454	10.34	0.5933	0.1469	0.057	0.0545	10.34
Oct-07	0.9454	10.34	0.5933	0.1469	0.057	0.0545	10.34
Nov-07	1.1995	10.63	0.6057	0.1482	0.0455	0.0632	10.63
Dec-07	1.1995	10.63	0.6057	0.1482	0.0455	0.0632	10.63

Table A- 2: Gas rates used in the models for Natural Gas Prices

Sources:

(1) KeySpan rates for Boston - Customer & distributions charges (http://gasrates.keyspanenergy.com/ne/NEGasrates/NEGasratesController)

(2) DPU Mass - GAF & LDAF for KeySpan Boston

(http://www.mass.gov/?pageID=ocasubtopic&L=7&L0=Home&L1=Government&L2=Our+Agencies+and+Divisions&L3=Department+of+Public+Utilities&L4=DPU+Divisions&L5=Gas+Division&L6=Cost+of+Gas+Adjustment+Information&sid=Eoca')

A.4. Micro-CHP efficiency and HPR

Thermal efficiency

For the definition of thermal efficiency in the micro-CHP unit, we are assuming that it is the difference between the overall efficiency and the electric efficiency of the machine:

$$\eta_{th}^{chp} = \eta^{chp} - \eta_e^{chp}$$

Where, η_e^{chp} is the micro-CHP electric efficiency, η_{th}^{chp} is the micro-CHP thermal efficiency, and η^{chp} is the micro-CHP overall efficiency [%].

In Figure A. 1 we see that electricity (e^{chp}) and heat (h^{chp}) outputs from the micro-CHP will depend on the electric and thermal efficiencies of the unit, and the amount of fuel being consumed by the machine (f^{chp}):

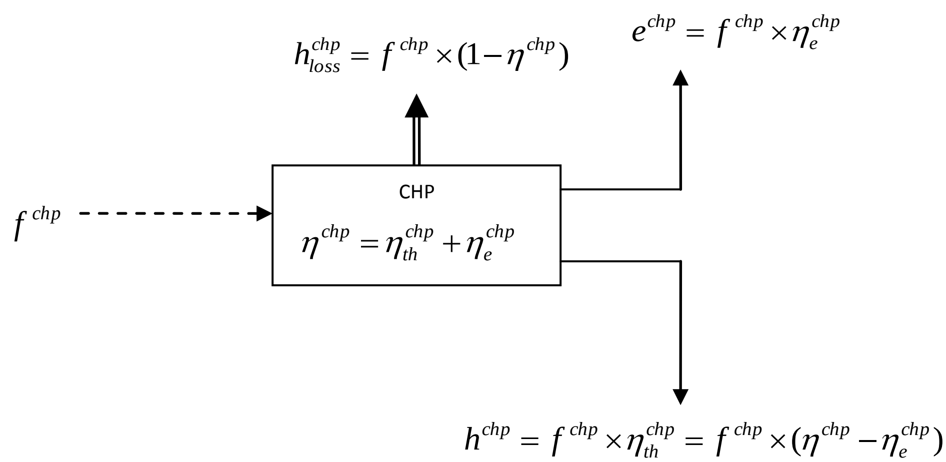

Figure A. 1 Micro-CHP energy outputs

Alternatively, we can think that the thermal efficiency can also be defined as $\eta_{th}^{chp} = \hat{\eta}_{th}^{chp} \times \left(1 - \eta_e^{chp}\right)$, where $\hat{\eta}_{th}^{chp}$ is the thermal efficiency of the heat recovery process after passing the electric generator.

Now, the overall efficiency of the micro-CHP unit will be defined as:

$$\eta^{chp} = \eta_e^{chp} + \hat{\eta}_{th}^{chp} \times (1 - \eta_e^{chp})$$

Which it is equivalent to our previous definition $\eta^{chp} = \eta_e^{chp} + \eta_{th}^{chp}$

In Figure A. 2 we see that electricity and heat outputs from the micro-CHP using this alternative definition:

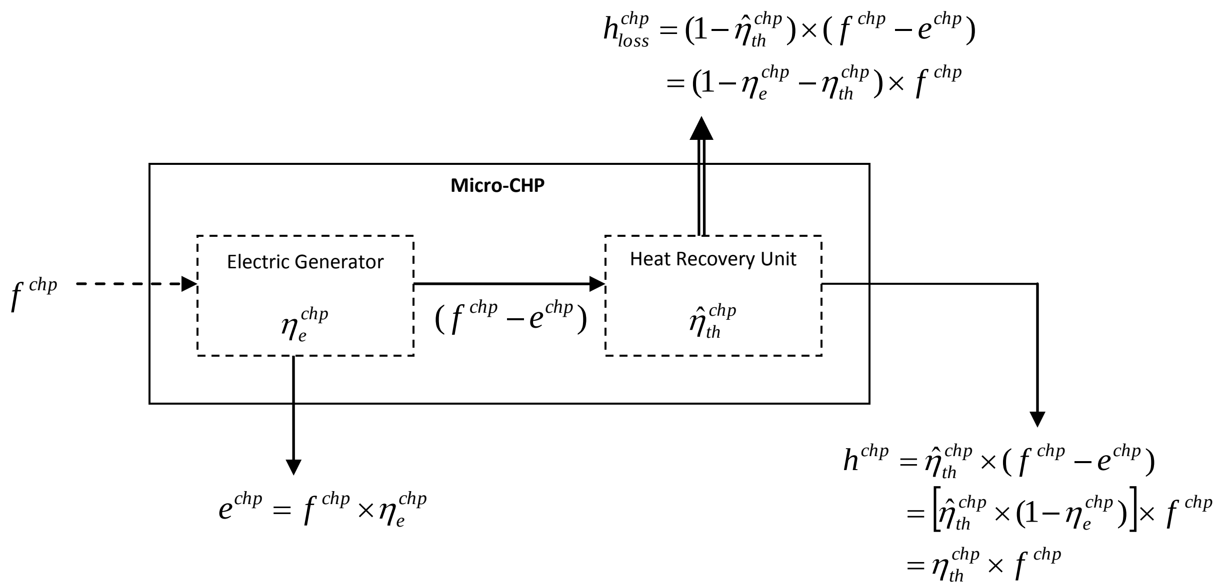

Figure A. 2: Micro-CHP energy outputs using alternative definition of thermal efficiency

Taking as an example the ICE-based micro-CHP we are using in the models, we have the following values:

$$\eta_{th}^{chp} = 66.8\%$$

$$\eta_e^{chp} = 24.4\%$$

$$\eta^{chp} = 91.2\%$$

Using the alternative definition we have that the thermal efficiency of the heat recovery process would be:

$$\hat{\eta}_{th}^{chp} = \frac{\eta_{th}^{chp}}{\left(1-\eta_e^{chp}\right)} = 88.4\%$$

Heat-to-power ratio

Ratio of heat to electricity generated by the micro-CHP unit is called Heat-to-Power Ratio (HPR). This relationship indicates that for each 1kWe of power generated, the micro-CHP will produce HPR units of heat. Therefore, it is defined as:

$$HPR = \frac{h^{chp}}{e^{chp}} \quad \text{(Eq. A1)}$$

Alternatively, as we have assumed the efficiency values to be constant throughout the entire micro-CHP operational range, the HPR may also be calculated using the efficiencies of the machine as follows:

$$HPR = \frac{\eta_{th}^{chp}}{\eta_e^{chp}} \quad \text{(Eq. A2)}$$

As shown below, this definition is equivalent to Eq. A1:

$$HPR = \frac{h^{chp}}{e^{chp}} = \frac{\eta_{th}^{chp} \times f^{chp}}{\eta_e^{chp} \times f^{chp}} = \frac{\eta_{th}^{chp}}{\eta_e^{chp}}$$

Alternatively, using the thermal efficiency of the heat recovery process we get the same relationship:

$$HPR = \frac{h^{chp}}{e^{chp}} = \frac{\left[\hat{\eta}_{th}^{chp} \times (1-\eta_e^{chp})\right] \times f^{chp}}{\eta_e^{chp} \times f^{chp}} = \frac{\hat{\eta}_{th}^{chp} \times (1-\eta_e^{chp})}{\eta_e^{chp}} = \frac{\eta_{th}^{chp}}{\eta_e^{chp}}$$

APPENDIX B

LARGE-SCALE DEPLOYMENT MODEL

B.1. Glossary of terms

af_g	Availability factor of generator g [p.u.]
$af_{p,dms}$	Availability factor of distributed technology dms, per season p [p.u.]
$af_{p,h}$	Availability factor of heating technology h, per season p [p.u.]
aux	Index for each type of conventional heating technology
b	Index for each energy block en the season p
c	Index for each type of customer class
$CO2_{year0}^{elec\&heat}$	Initial system CO2 emissions (year 0) from production electricity & heat
d	Index for each day of the year y
d_h	System electric demand per hour h for initial year t0 [MW]
$d_{d,h}$	System electric demand for every day d and hour h [MW]
$d'_{d,h}$	Residual system electric demand for day d and hour h [MW]
$d_{p,b}^{elec}$	System electric demand per season p and block b [GW]
$d_{p,b,c}^{heat}$	Heat demand per customer class c per season p and block b [GW]
DC	Annual system distribution costs [$]
dce_b	Micro-CHP owners network costs savings – in the form of energy component – per energy block b [$/kWh]
dms	Index for each type of electric distributed technology, i.e. micro-CHP
dr	Real discount rate [%]
$du_{p,b}$	Time duration of energy block b of season p [hr]
$e_{h,c}^{imp}$	Electricity purchased from the grid every hour h by customer class c [MWe]
$eclf_g$	Economic lifetime per generator g [yr]
$eclf_{dms}$	Economic lifetime per distributed technology dms [yr]

$eclf_h$	Economic lifetime per heating technology h [yr]
$ef_{aux,c}$	CO2 emission rate per heating technology aux used by customer class c [ton/MMBtu]
ef_g	CO2 emission rate per generator g [ton/MMBtu]
$ef_{dms,c}$	CO2 emission rate per distributed technology dms used by customer class c [ton/MMBtu]
ef_h	CO2 emission rate per heating technology h [ton/MMBtu]
$Error\_SRMP_d^{iter}$	Electricity marginal price error for day d and iteration $iter$
esc_y	Annual escalation factor [%/yr]
exc^{cost}	Cost of excess energy [$/kWh]
f_g	Fuel cost for generator g [$/MMBtu]
f_{dms}	Fuel cost for distributed technology dms [$/MMBtu]
f_h	Fuel cost for heating technology h [$/MMBtu]
fca_g	Annual investment cost per generator g [$/kWyr]
fca_{dms}	Annual investment cost per distributed technology dms [$/kWyr]
fca_h	Annual investment cost per heating technology h [$/kWyr]
$fuel_{h,g}$	Fuel consumption by generator g, per hour h [MW]
$fuel_{h,dms,c}$	Fuel consumption by distributed technology dms, per hour h, per customer class c [MW]
$fuel_{h,aux,c}$	Fuel consumption for heating technology aux, per hour h, per customer class c [MW]
g	Index for each type of thermo-electric generator
GC	Annual system generation costs [$]
gr_y	Electric demand growth rate per year y [p.u.]
h	Index for each hour of the day d
hr_g	Electric heat rate of generator g [MMBtu/MWh]
hr_g^{elec}	Electric heat rate of generator g [MMBtu/kWhe] or [MMBtu/MWhe]
hr_{dms}^{elec}	Electric heat rate of distributed technology dms [MMBtu/kWhe]
$hr_{dms,c}^{elec}$	Electric heat rate of distributed technology dms per customer class c [MMBtu/MWhe]
hr_h^{heat}	Thermal heat rate of heating technology h [MMBtu/kWhth]
$hr_{h,c}^{heat}$	Thermal heat rate of heating technology h per customer class c [MMBtu/kWhth]
$IC_{y,g}^{elec}$	Installed electric capacity of generator g, per year y [GW]

$IC_{y,dms}^{elec}$	Installed electric capacity of distributed technology dms, per year y [GW]
$IC_{y,h}^{heat}$	Installed heat capacity of heating technology h, per year y [GW]
$Income_{d,g}^{extra}$	Extra income received by generator g on day d [$/day]
$Income_{d,g}^{total}$	Total income received by generator g on day d [$/day]
$IT_{dms,c}$	Connection decision of micro-CHP dms per customer class c [0/1]
$iter$	Index for each iteration
lf	Network energy loss factor [%]
NCE_h	Energy component of the network costs for hour h [$/MWh]
nl_g	No-load fuel cost for generator g [$/h]
nse^{cost}	Cost of non-served energy [$/kWh]
nsp^{cost}	Cost of non-served or excess of electric power reserve [$/kW]
$OFF_{d,h,g}$	Shutdown decision for thermal unit g, day d and hour h [p.u.]
$ON_{d,h,g}$	Startup decision for thermal unit g, day d and hour h [p.u.]
opr	Long-term demand reserve requirement [%]
p	Index for each season en the year y
$\overline{p}_g$	Maximum electric output for thermo-electric generator g [MW]
$\overline{p}_{chp}$	Maximum electric capacity for micro-CHP [MW]
$\overline{p}_g^{elec}$	Existent installed electric capacity per generator g [GW]
$\overline{p}_{dms}^{elec}$	Existent installed electric capacity per distributed technology dms [GW]
$\overline{p}_h^{heat}$	Existent installed heat capacity per heating technology h [GW]
p_y^{CO2}	CO2 price per year y [$/ton]
$P_{y,p,nse}^{elec}$	Non-served electric reserve power per year y, and season p [GW]
$P_{y,p,excess}^{elec}$	Excess electric reserve power per year y, and season p [GW]
$Payment_d^{total}$	Total load payment day d [$/day]
$q_{d,h,chp}$	Micro-CHP electric production output - from HH model - for day d and hour h [MW]
$Q_{d,h,g}$	Electric generation for generator g, day d and hour h [MW]
$Q_{d,h,nse}$	Non-served electricity for day d and hour h [MW]
$Q_{h,g}^{elec}$	Electric production by generator g, per hour h [MW]
$Q_{h,dms,c}^{elec}$	Electric production by distributed technology dms, per hour h, per customer class c

	[MW]
$Q^{elec}_{y,b,p,g}$	Electric generation production of generator g, per year y, block b and season p [GW]
$Q^{heat}_{h,aux,c}$	Heat production by heating technology aux, per hour h, per customer class c [MW]
$Q^{elec}_{y,b,p,dms}$	Electric generation production of distributed technology dms, per year y, block b and season p [GW]
$Q^{heat}_{h,dms,c}$	Heat production by distributed technology dms, per hour h, per customer class c [MW]
$Q^{heat}_{y,b,p,h}$	Heat generation production of heating technology h, per year y, block b and season p [GW]
$Q^{elec}_{y,b,p,nse}$	Non-served electric energy per year y, block b, and season p [GW]
$Q^{elec}_{y,b,p,excess}$	Excess electric energy per year y, block b, and season p [GW]
$Q^{heat\_waste}_{h,dms,c}$	Excess heat produced by distributed technology dms, per hour h, per customer class c [MW]
Q^{nse}_{h}	Non-served electricity per hour h [MW]
rm	Spinning electric reserve [%]
$SRMP_{d,h}$	Electric system marginal price for hour h of day d [$/MWh/day]
$SRMP^{iter}_{h}$	Electric system marginal price for hour h, iteration $iter$ [$/MWh]
$SRMP^{UP,iter}_{h}$	Electric system marginal price with uplift charge for hour h, iteration $iter$ [$/MWh]
su_g	Startup cost generator g [$]
TC	Annual system transmission costs [$]
tcp_g	Annual electric transmission cost - in the form of capacity charge – for generator g [$/kWyr]
TH	Long-term study time horizon [yr]
$UC_{d,h,g}$	Commitment decision for thermal unit g, day d and hour h [p.u.]
$Uplift_{d,h\in peak\_hours}$	Uplift charge paid by load during peak hours of day d [$/MWh/day]
$VC_{h,g}$	Variable cost of operating generator g, per hour h [$/MWh]
$VC_{d,h,g}$	Variable cost of operating generator g, per day d and hour h [$/MWh]
$VC_{h,dms,c}$	Variable costs of operating micro-CHP dms, per hour h, per customer class c [$/MWh]
$VC_{h,aux,c}$	Variable costs of operating heating technology aux, per hour h and customer class c [$/MWh]
$VC^{class}_{d,h,aux}$	Variable costs of operating a conventional heating system, per customer class, day d and hour h [$/MWh]
$VC^{class}_{d,h,chp}$	Variable cost of operating micro-CHPs, per customer class, day d and hour h [$/MWh]
$voll$	Non-served energy cost [$/MWh]

vom_g	Operation & maintenance (O&M) variable cost for generator g [$/MWh or kWh]
vom_{dms}	O&M variable cost per distributed technology dms [$/kWh]
vom_h	O&M variable cost per heating technology h [$/kWh]
$welfare_d$	Economic social welfare for day d [$/day]
y	Index for each year of the time horizon
$Z_{y,b,p,g}$	Connection decision of generator g, per year y, block b, and season p [0/1]
$\%_{h,c}^{elec}$	Proportion of purchased electricity from the grid by customer class c per hour h
$\%^{reduction}$	Micro-CHP capital cost reduction [%]

B.2. Electricity and heat values per energy block, season, and customer class

Summer									
Block Elec	Hours	% Time	Block Heat	Hours	% Time	Power	Heat	Heat_C1	Heat_C2
	[hr/bl]	[%/bl]		[hr/bl]	[%/bl]	[MW/bl]	[MW/bl]	[MW/bl]	[MW/bl]
B1	22	1.0%	**b1**	2	10%	**24,866**	**7,972**	**3,695**	**4,276**
			b2	3	15%	**25,624**	**6,555**	**2,992**	**3,563**
			b3	6	25%	**25,655**	**5,314**	**2,464**	**2,851**
			b4	7	30%	**25,560**	**4,551**	**2,413**	**2,138**
			b5	4	20%	**25,585**	**4,250**	**2,112**	**2,138**
B2	221	10.0%	**b1**	22	10%	**22,112**	**9,034**	**4,223**	**4,811**
			b2	33	15%	**22,690**	**7,021**	**3,296**	**3,725**
			b3	55	25%	**21,981**	**6,164**	**2,956**	**3,207**
			b4	66	30%	**22,644**	**5,078**	**2,600**	**2,478**
			b5	44	20%	**22,564**	**4,250**	**2,112**	**2,138**
B3	596	27.0%	**b1**	60	10%	**19,213**	**9,875**	**4,770**	**5,105**
			b2	89	15%	**19,034**	**8,712**	**4,465**	**4,246**
			b3	149	25%	**19,371**	**6,761**	**3,242**	**3,519**
			b4	179	30%	**18,806**	**5,834**	**2,908**	**2,926**
			b5	119	20%	**19,249**	**4,463**	**2,280**	**2,183**
B4	684	31.0%	**b1**	68	10%	**16,127**	**9,905**	**4,826**	**5,079**
			b2	103	15%	**16,118**	**8,167**	**4,270**	**3,897**
			b3	171	25%	**16,074**	**6,321**	**3,139**	**3,182**
			b4	205	30%	**15,822**	**5,331**	**2,862**	**2,469**
			b5	137	20%	**15,410**	**3,320**	**1,689**	**1,631**
B5	684	31.0%	**b1**	68	10%	**13,621**	**7,635**	**4,188**	**3,447**
			b2	103	15%	**12,863**	**5,284**	**2,710**	**2,574**
			b3	171	25%	**12,298**	**3,258**	**1,408**	**1,850**
			b4	205	30%	**12,610**	**2,125**	**1,056**	**1,069**
			b5	137	20%	**10,696**	**2,125**	**1,056**	**1,069**

Table B- 1: Electricity and heat values for summer season, per block and customer class

Winter									
Block Elec	**Hours**	**% Time**	**Block Heat**	**Hours**	**% Time**	**Power**	**Heat**	**Heat_C1**	**Heat_C2**
	[hr/bl]	[%/bl]		[hr/bl]	[%/bl]	[MW/bl]	[MW/bl]	[MW/bl]	[MW/bl]
B1	66	1.0%	**b1**	7	10%	**20,730**	**55,293**	**32,420**	**22,874**
			b2	10	15%	**20,812**	**45,671**	**27,464**	**18,207**
			b3	16	25%	**20,874**	**30,159**	**18,606**	**11,553**
			b4	20	30%	**21,281**	**5,860**	**2,840**	**3,020**
			b5	13	20%	**21,510**	**4,372**	**2,234**	**2,138**
B2	655	10.0%	**b1**	66	10%	**18,775**	**76,123**	**42,328**	**33,795**
			b2	98	15%	**18,983**	**58,331**	**32,641**	**25,690**
			b3	164	25%	**18,934**	**44,865**	**25,608**	**19,257**
			b4	197	30%	**18,860**	**27,834**	**16,396**	**11,438**
			b5	131	20%	**18,895**	**6,251**	**3,202**	**3,050**
B3	1,769	27.0%	**b1**	177	10%	**17,122**	**70,265**	**38,195**	**32,070**
			b2	265	15%	**17,027**	**50,623**	**28,251**	**22,372**
			b3	442	25%	**17,016**	**35,062**	**19,554**	**15,508**
			b4	531	30%	**16,931**	**13,996**	**7,561**	**6,435**
			b5	354	20%	**16,876**	**5,299**	**2,644**	**2,655**
B4	2,031	31.0%	**b1**	203	10%	**14,778**	**76,744**	**42,086**	**34,658**
			b2	305	15%	**14,985**	**49,327**	**28,170**	**21,157**
			b3	508	25%	**14,993**	**30,195**	**16,828**	**13,368**
			b4	609	30%	**15,119**	**10,280**	**5,700**	**4,579**
			b5	406	20%	**15,038**	**4,646**	**2,373**	**2,273**
B5	2,031	31.0%	**b1**	203	10%	**12,320**	**79,051**	**46,214**	**32,838**
			b2	305	15%	**12,112**	**48,668**	**33,112**	**15,556**
			b3	508	25%	**12,060**	**25,191**	**14,269**	**10,922**
			b4	609	30%	**11,884**	**6,773**	**3,776**	**2,997**
			b5	406	20%	**10,930**	**2,241**	**1,098**	**1,143**

Table B- 2: Electricity and heat values for winter season, per block and customer class

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APPENDIX C

LARGE-SCALE DEPLOYMENT RESULTS

C.1. Levelized heat cost after savings with micro-CHPs & conventional heating technologies

Based on the notion of levelized cost of heat to estimate the total cost (fixed & variable) of generating heat, we can approximately see how the system chooses one technology over another as capital cost & NG retail prices vary.

First, we estimate the *fixed costs per heating technology*, considering their annualized capital costs over an evaluation period of 20 years. We note that the total fixed cost (FC) component is the largest for micro-CHPs with the lowest HPR, while the fixed cost is the lowest for micro-CHPs with the highest HPR. For example, a micro-CHP with HPR0.6 produces 0.6kWth per 1kWe, while a micro-CHP with HPR7.0 produces 7kWth per each unit of electricity. Thus, the fixed cost per output of heat is the lowest on those technologies able to produce more heat, if the capital cost (in $ per units of installed electric capacity) is the same for all technologies[182].

Then, we estimate the *variable cost including the potential* savings for simultaneously produce electricity[183]. Here we note that the variable cost of producing heat-only is more expensive for micro-CHPs with low HPR (a micro-CHP with HPR0.6 has the highest thermal heat rate, while the micro-CHP with a HPR7.0 has the lowest one). However, as micro-CHPs also produce electricity, in their final variable cost we include the savings for not purchasing that electricity from the grid. The largest savings are for micro-CHPs with low HPR. Thus, depending on the electricity price used to value these savings, the variable cost (after savings) could be cheaper for micro-CHPs with HPR0.6.

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[182] For example, if the fixed cost is 7,000[$/kWe] then the fixed cost "per units of heat" for a micro-CHP of HPR0.6 will be ~11,500[$/kWth], for a micro-CHP of HPR2.7 will be ~2,500[$/kWth], while for a micro-CHP of HPR7.0 will be ~1,000[$/kWth]. For a conventional heating unit we assumed a capital cost of about 250[$/kWth].

[183] There is the challenge in determining the total cost of producing heat with micro-CHP units, as the economic effect of simultaneously producing electricity has to be included within the calculations. In the long-term expansion model, we do not have this problem as both electricity and heat demand are explicitly included in the simulations. Thus, for the production cost curves we need to make some assumptions to try to get results similar to the ones being provided by the expansion model. In particular:

- We assumed fuel prices and CO2 price of year t20.
- Variable cost of producing heat and electricity includes a CO2 price, and the savings for generating electricity.
- The production of electricity from micro-CHP is priced at a price of electricity equal to 0.140$/kWhe.

The variable cost - per units of heat - because of fuel consumption, variable O&M, and Carbon price is given by:

$$VC(d) = HR_{th}(d) \times Price_{NG} + O\&M(d) + Price_{CO2} \times HR_{th}(d) \times EF_{natural\ gas}\ [\frac{\$}{kWh\_th}]$$

Where,

$\mathrm{HR_{th}(d)}$ is thermal heat rate per micro-CHP technology $[\mathrm{mmBtu/kWh\_th}]$,

$\mathrm{Price_{NG}}$ is natural gas retail price $[\$/\mathrm{mmBtu}]$,

$\mathrm{O\&M(d)}$ is the variable O&M per micro-CHP technology $[\$/\mathrm{kWh\_th}]$ [184],

$\mathrm{HPR(d)}$ is the heat-to-power ratio per the micro-CHP unit $[\mathrm{p.u}]$,

η_e and η_{th} are the electric and thermal efficiency per micro-CHP technology $[\%]$.

$\mathrm{EF_{natural\ gas}}$ is the CO2 emission factor of NG equal to 0.05526 $[\mathrm{CO2ton/mmBTU}]$,

$\mathrm{Price_{CO2}}$ is the CO2 price, which we assume 98.74 $[\$/\mathrm{ton}]$.

For each micro-CHP, their variable costs are as follows[185]:

		Micro-CHP 2.7	**Micro-CHP 0.6**	**Micro-CHP 7.0**	**Boiler**
η_{th} (η_e)	[%]	66.8% (24.4%)	30% (50%)	78% (11%)	95% (N/A)
$HPR(d)$	[p.u.]	2.74	0.60	7.09	N/A
$HR_{th}(d)$	[Btu/kWh_th]	5,109	11,376	4,375	3,592
$\mathrm{Price_{NG}}$	[$/MMBtu]	17.752	17.752	17.752	17.752
$\mathrm{EF_{NG}}$	[ton/MMBtu]	0.0553	0.0553	0.0553	0.0553
$\mathrm{Price_{CO2}}$	[$/ton]	98.74	98.74	98.74	98.74
$\mathbf{VC(d)}$	**[$/kWh_th]**	**0.1186**	**0.2640**	**0.1015**	**0.0834**

We see from this calculation that the micro-CHP with the lowest HPR has the most expensive variable cost per unit of heat.

However, when considering the savings because of the simultaneous production of electricity by micro-CHPs, the costs order of the heating technologies changes. Now, in the variable cost calculations we include the savings for electricity:

$$Electricity\ savings\ \left[\frac{\$}{kWh\_th}\right] = -\frac{1}{HPR(d)}\left[\frac{kWh\_e}{kWh\_th}\right] \times Price_{electricity}\ [\frac{\$}{kWh\_e}]$$

Where,

$\mathrm{1/HPR(d)}$ is the ratio of electricity-to-heat, i.e. how much electricity is generated per unit of heat produced by the micro-CHP unit $[\mathrm{p.u}]$,

$\mathrm{Price_{electricity}}$ is the value of electricity, which we assume 0.140 $[\$/\mathrm{kWh\_e}]$ for this calculations[186]

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184 Variable O&M is assumed to be the same for all technologies. For simplicity, for these calculations we are assuming a value of 0 [$/kWh_th].

185 Variable O&M is assumed to be the same for all technologies. For simplicity, for these calculations we are assuming a value of 0 [$/kWh_th].

186 See footnote #159.

For each micro-CHP, now their variable costs (after savings) are:

		Micro-CHP 2.7	Micro-CHP 0.6	Micro-CHP 7.0	Boiler
VC(d)	[$/kWh_th]	0.1186	0.2640	0.1015	0.0834
HPR(d)	[p.u.]	2.74	0.60	7.09	N/A
1/HPR(d)	[p.u.]	0.365	1.667	0.141	N/A
$\text{Price}_{\text{electricity}}$	[$/kWh_e]	0.140	0.140	0.140	N/A
VC after savings	**[$/kWh_th]**	**0.0674**	**0.0307**	**0.0818**	**0.0834**

As the micro-CHP with low HPR can generate more electricity per unit of heat than the other units, the savings for electricity are substantial when $\text{Price}_{\text{electricity}}$ is high. Thus, its final variable cost decreases at a level below to the other technologies.

Finally, taking the annualized fixed costs, the variable costs and the electricity savings, we estimated the *levelized cost of heat (after savings)* for all heating technologies as shown in Table C- 1:

Cost of HEAT after savings		Boiler	mCHP2.7	mCHP0.6	mCHP7.0
Capital Cost	($2007/kWth)	242	1,636	7,467	632
Evaluation period	(years)	20	20	20	20
Capital recovery factor	(%)	9.4%	9.4%	9.4%	9.4%
Fixed O&M	($2007/kWth)	-	-	-	-
Tx. costs paid by capacity charge	*($2007/kW)*	-	-	-	-
Total fixed cost	*($2007/kWth)*	*22.84*	*141.75*	*646.78*	*54.73*
Capacity Factor	*(%)*	*85%*	*85%*	*85%*	*85%*
Operating hours	(hr)	7,446	6,800	6,800	7,446
CC & FOM recovery required	*($2007/kWh_th)*	*0.003*	*0.021*	*0.095*	*0.007*
Variable O&M	*($2007/kWh_th)*	-	-	-	-
Heat rate "thermal"	(BTU/kWh_th)	3,592	5,109	11,376	4,375
Fuel cost year t20	($2007/mmBTU)	17.752	17.752	17.752	17.752
Emission factor	(CO2 ton/mmBTU)	0.05526	0.055	0.055	0.055
CO2 price year t20	*($2007/ton)*	*98.74*	*98.74*	*98.74*	*98.74*
Variable fuel & CO2 cost	*($2007/kWh_th)*	*0.0834*	*0.0674*	*0.0307*	*0.0818*
Network losses on conv. power plants (10%)	*[$2007/kWh]*	-	-	-	-
Levelized cost of HEAT	**($2007/kWh_th)**	**0.0864**	**0.0883**	**0.1258**	**0.0892**
HPR	(kWth/kWe)	N/A	2.74	0.60	7.09
Price electricity	($/kWh_e)	0.140			

Table C- 1: Illustration of calculations used to estimate levelized cost of heat (after savings) per technology

Clearly, the economic valuation of the electricity savings plays a key role on the system's choice regarding the heating technologies to use to meet energy demand. If the price is high, it will favor those technologies that bring the largest electricity savings as in the case of micro-CHPs with low HPR.

C.2. Capital cost sensitivity - Fraction of installed capacity within electric portfolio at the end of the time horizon for conventional generating & micro-CHP technologies

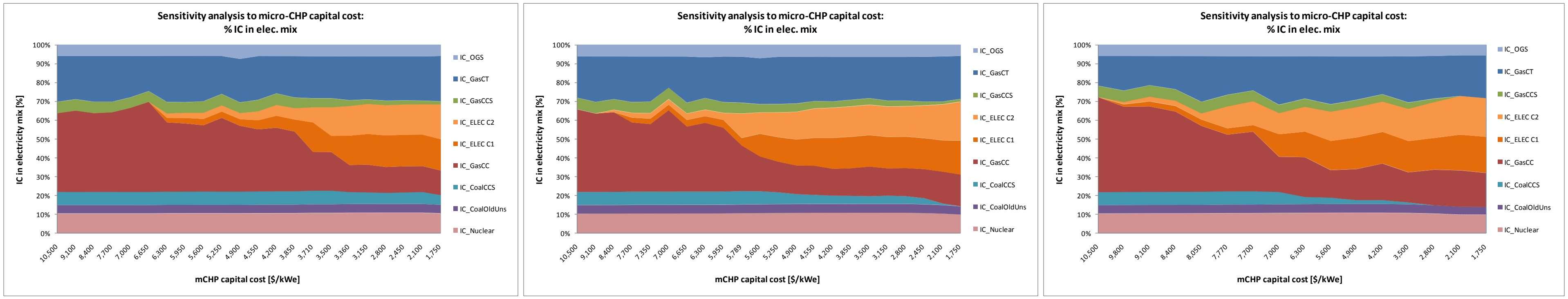


Figure C. 1: (a) High CO2 price & High NG retail price, (b) High CO2 price & Medium NG retail price, (c) High CO2 price & Low NG retail price

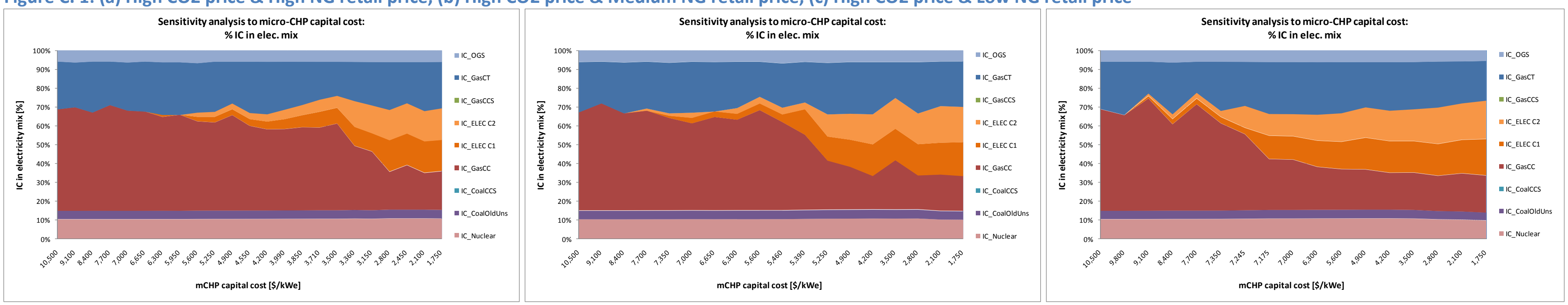


Figure C. 2: (a) Medium CO2 price & High NG retail price, (b) Medium CO2 price & Medium NG retail price, (c) Medium CO2 price & Low NG retail price

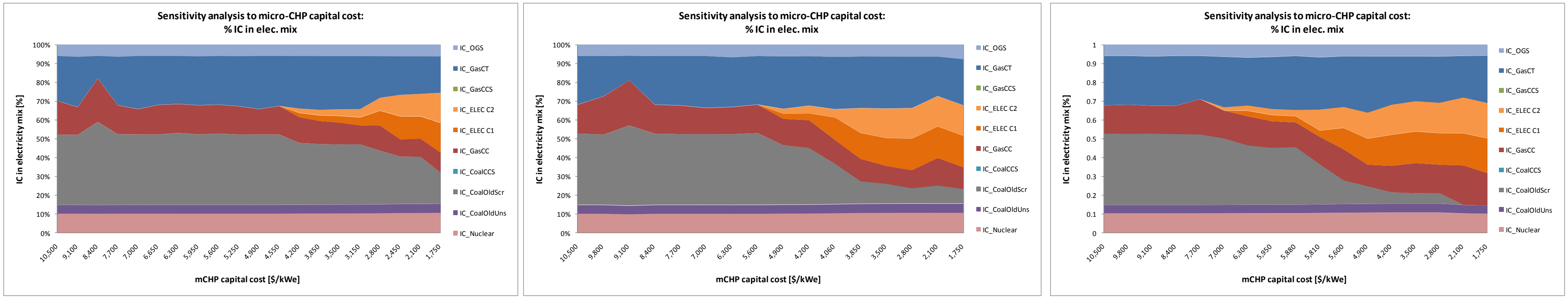


Figure C. 3: (a) No CO2 price & High NG retail price, (b) No CO2 price & Medium NG retail price, (c) No CO2 price & Low NG retail price

C.3. Capital cost sensitivity - Micro-CHP penetration and its effect on CO2 emissions

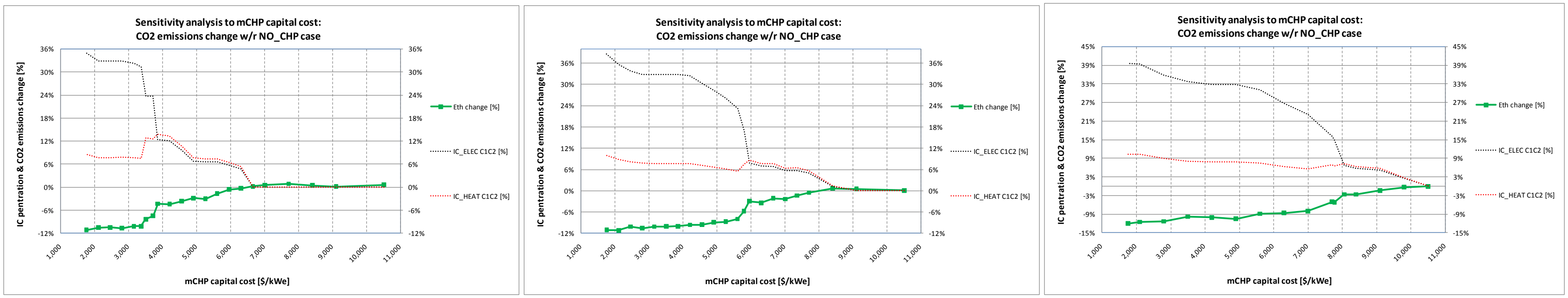


Figure C. 4: (a) High CO2 price & High NG retail price, (b) High CO2 price & Medium NG retail price, (c) High CO2 price & Low NG retail price

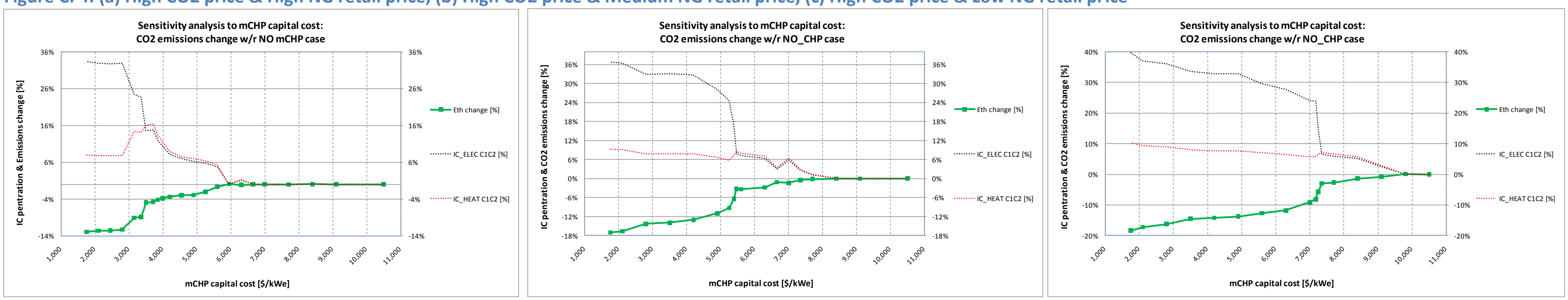


Figure C. 5: (a) Medium CO2 price & High NG retail price, (b) Medium CO2 price & Medium NG retail price, (c) Medium CO2 price & Low NG retail price

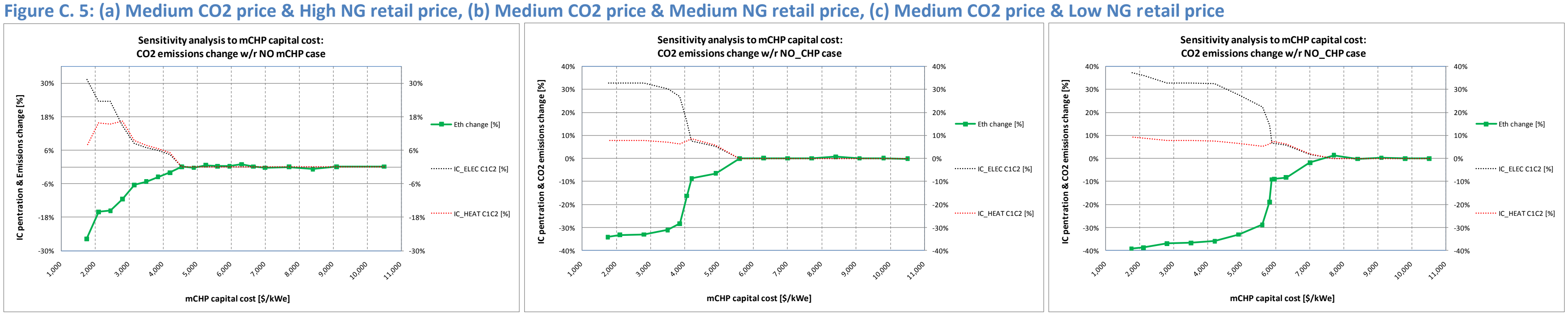


Figure C. 6: (a) No CO2 price & High NG retail price, (b) No CO2 price & Medium NG retail price, (c) No CO2 price & Low NG retail price

C.4. Capital cost sensitivity - Micro-CHP penetration per technology for customer class C1

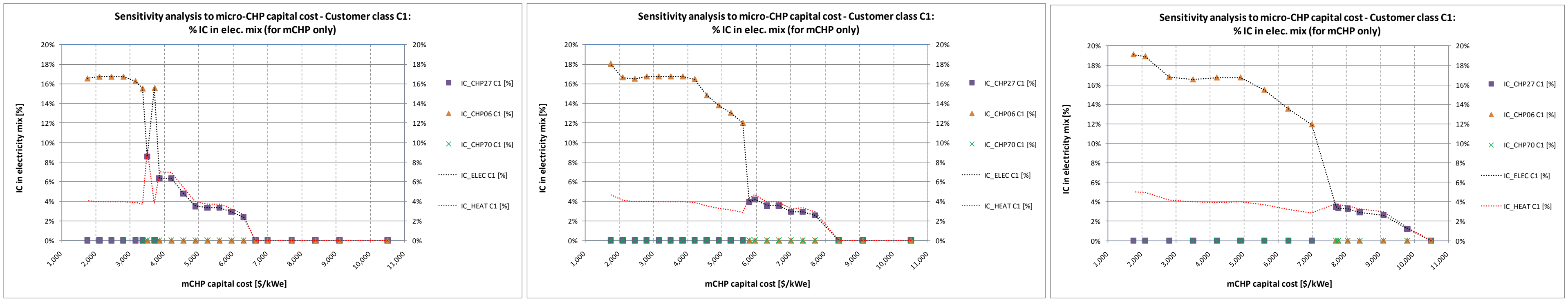


Figure C. 7: (a) High CO2 price & High NG retail price, (b) High CO2 price & Medium NG retail price, (c) High CO2 price & Low NG retail price

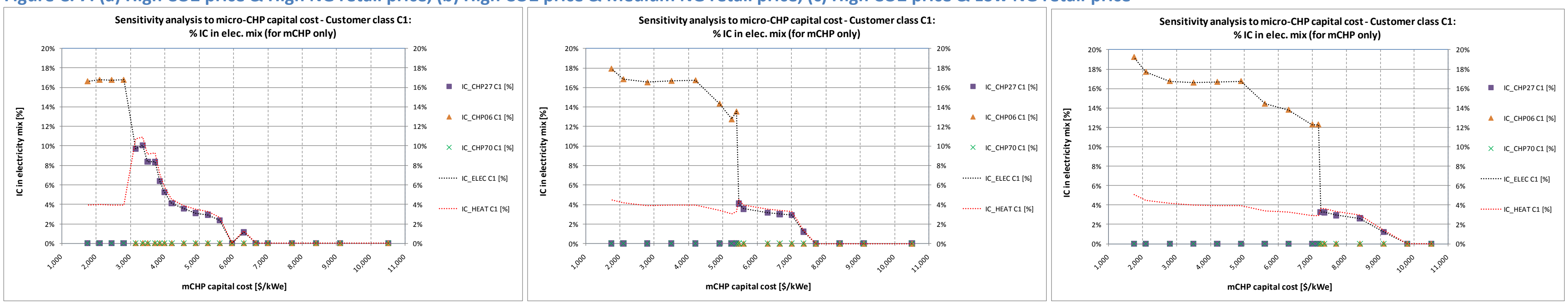


Figure C. 8: (a) Medium CO2 price & High NG retail price, (b) Medium CO2 price & Medium NG retail price, (c) Medium CO2 price & Low NG retail price

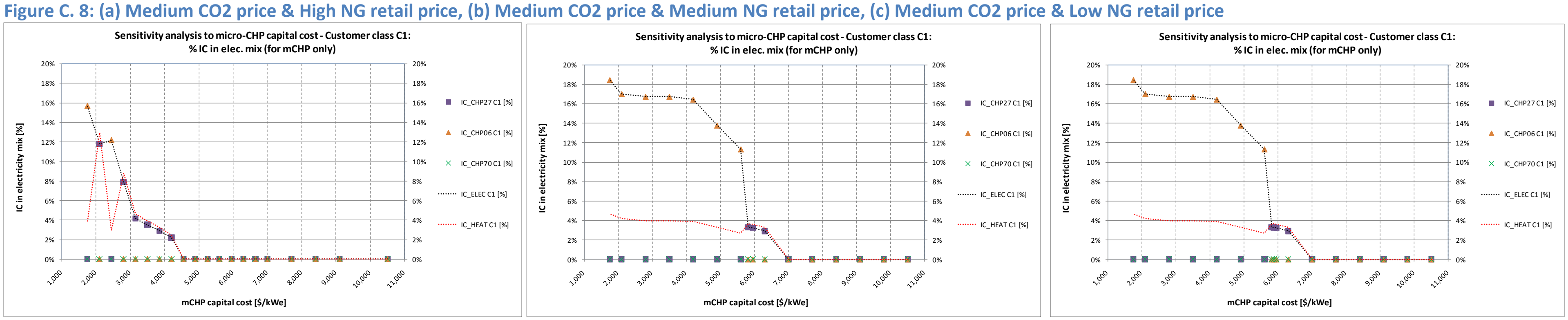


Figure C. 9: (a) No CO2 price & High NG retail price, (b) No CO2 price & Medium NG retail price, (c) No CO2 price & Low NG retail price

C.5. Capital cost sensitivity - Micro-CHP penetration per technology for customer class C2

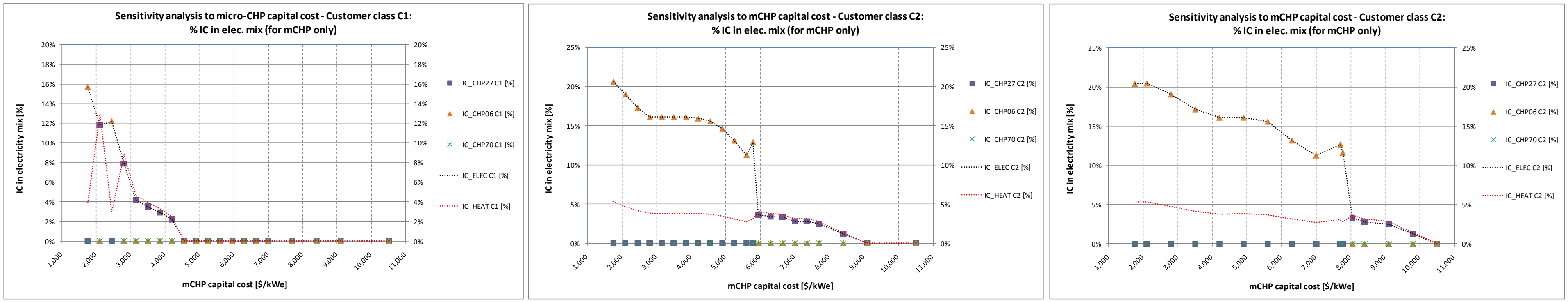


Figure C. 10: (a) High CO2 price & High NG retail price, (b) High CO2 price & Medium NG retail price, (c) High CO2 price & Low NG retail price

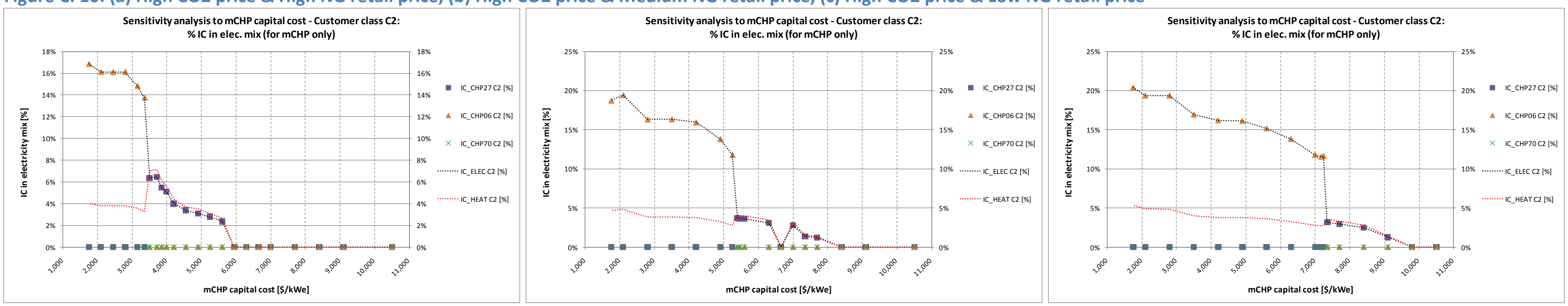


Figure C. 11: (a) Medium CO2 price & High NG retail price, (b) Medium CO2 price & Medium NG retail price, (c) Medium CO2 price & Low NG retail price

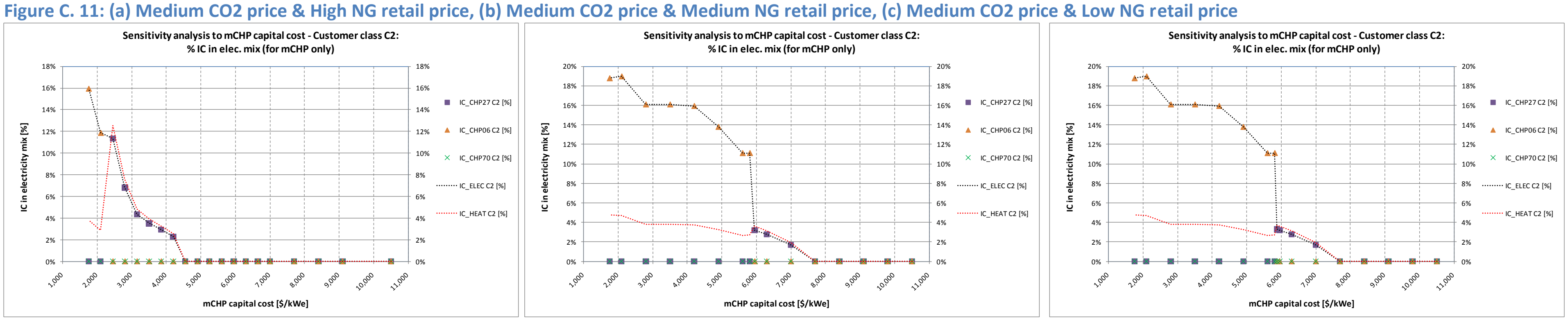


Figure C. 12: (a) No CO2 price & High NG retail price, (b) No CO2 price & Medium NG retail price, (c) No CO2 price & Low NG retail price

C.6. NG retail price sensitivity - Fraction of installed capacity within electric portfolio at the end of the time horizon for conventional generating & micro-CHP technologies

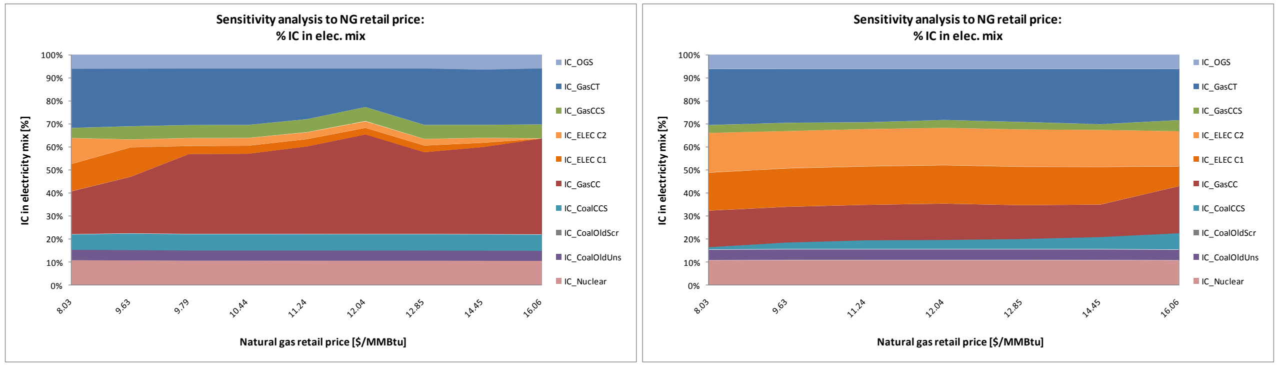


Figure C. 13: (a) High CO2 price & High micro-CHP capital cost, (b) High CO2 price & Medium micro-CHP capital cost

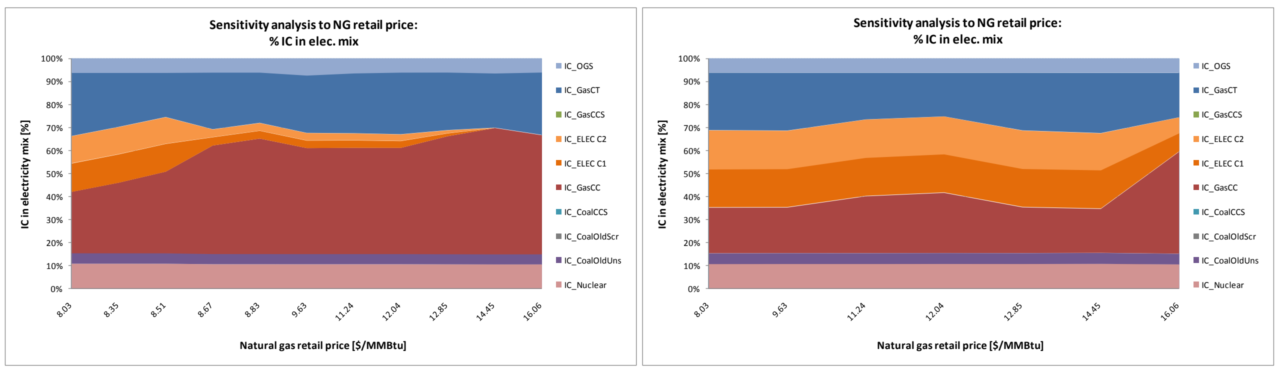


Figure C. 14: (a) Medium CO2 price & High micro-CHP capital cost, (b) Medium CO2 price & Medium micro-CHP capital cost

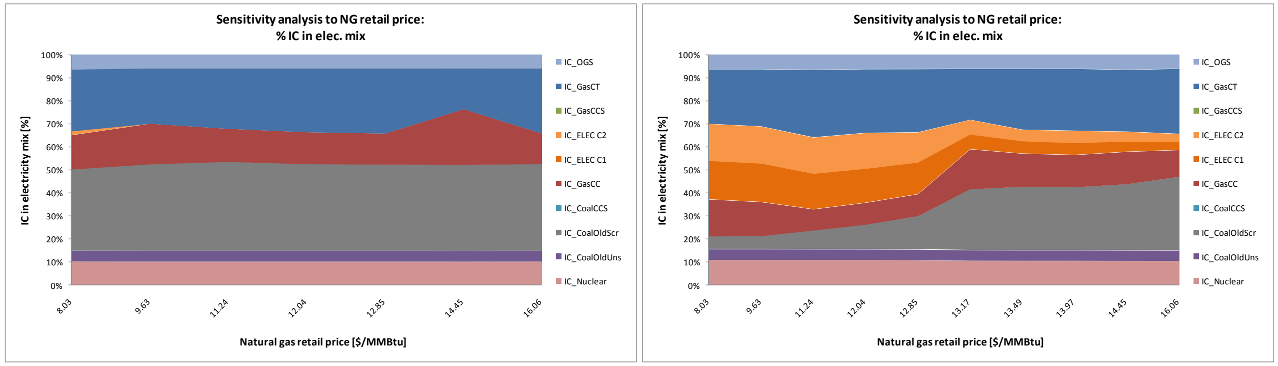


Figure C. 15: (a) No CO2 price & High micro-CHP capital cost, (b) No CO2 price & Medium micro-CHP capital cost

C.7. NG retail price sensitivity - Micro-CHP penetration and its effect on CO2 emissions

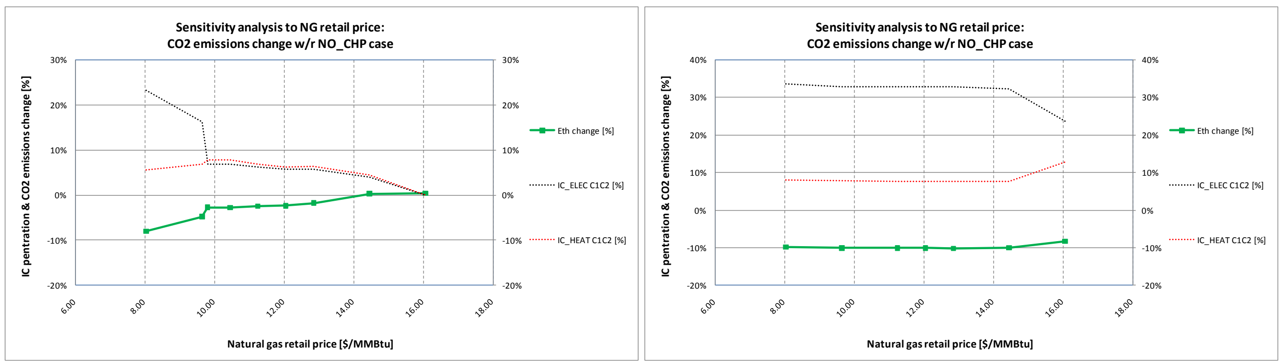


Figure C. 16: (a) High CO2 price & High micro-CHP capital cost, (b) High CO2 price & Medium micro-CHP capital cost

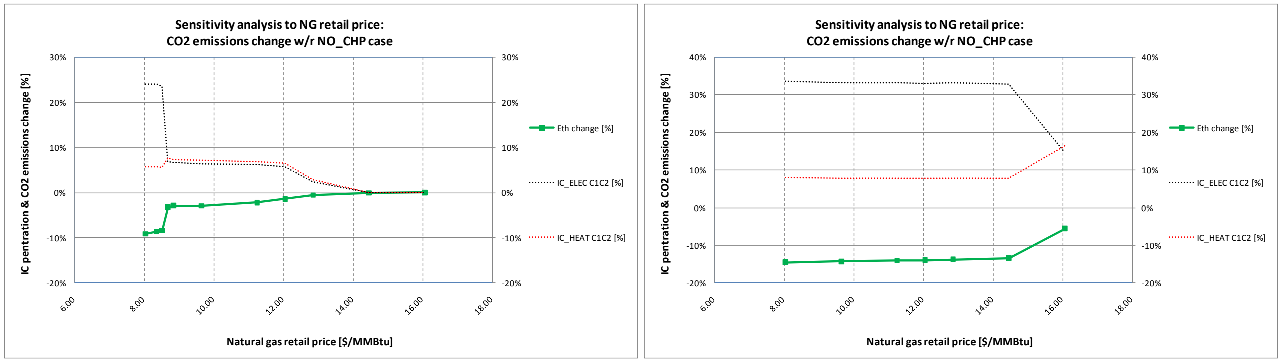


Figure C. 17: (a) Medium CO2 price & High micro-CHP capital cost, (b) Medium CO2 price & Medium micro-CHP capital cost

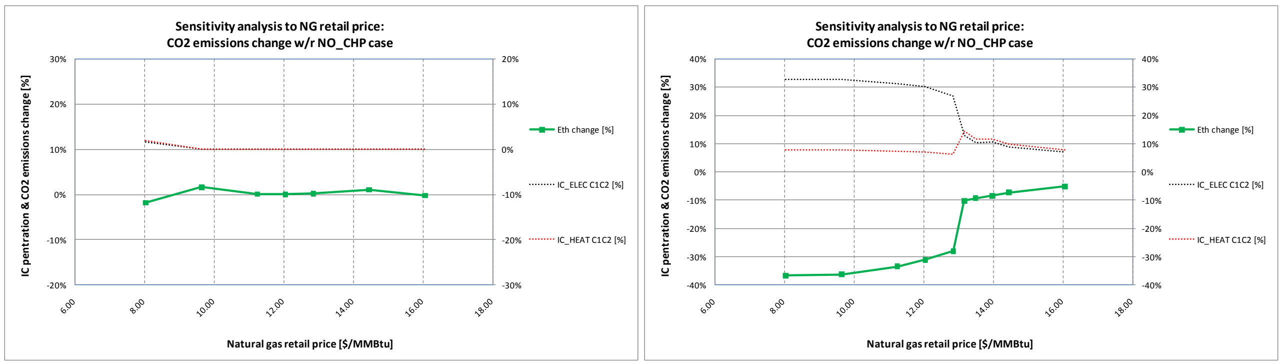


Figure C. 18: (a) No CO2 price & High micro-CHP capital cost, (b) No CO2 price & Medium micro-CHP capital cost

C.8. NG retail price sensitivity - Micro-CHP penetration per technology for customer class C1

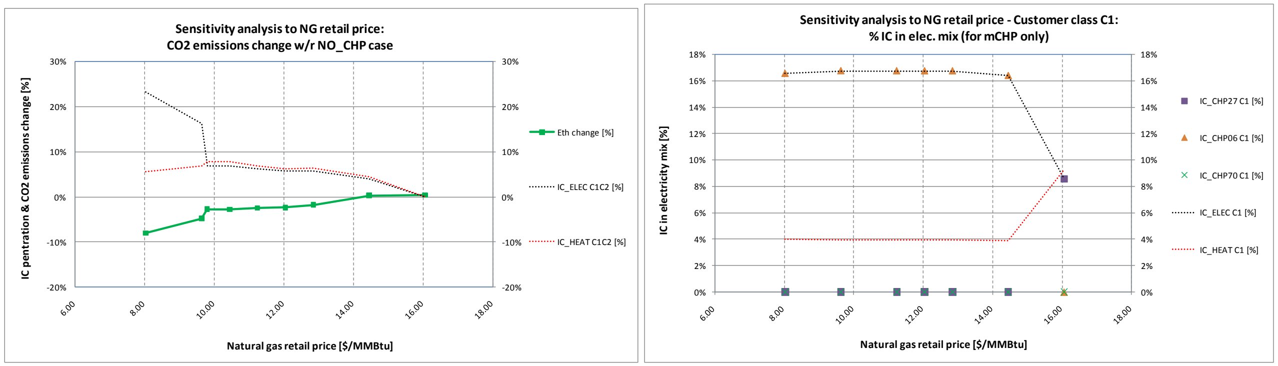


Figure C. 19: (a) High CO2 price & High micro-CHP capital cost, (b) High CO2 price & Medium micro-CHP capital cost

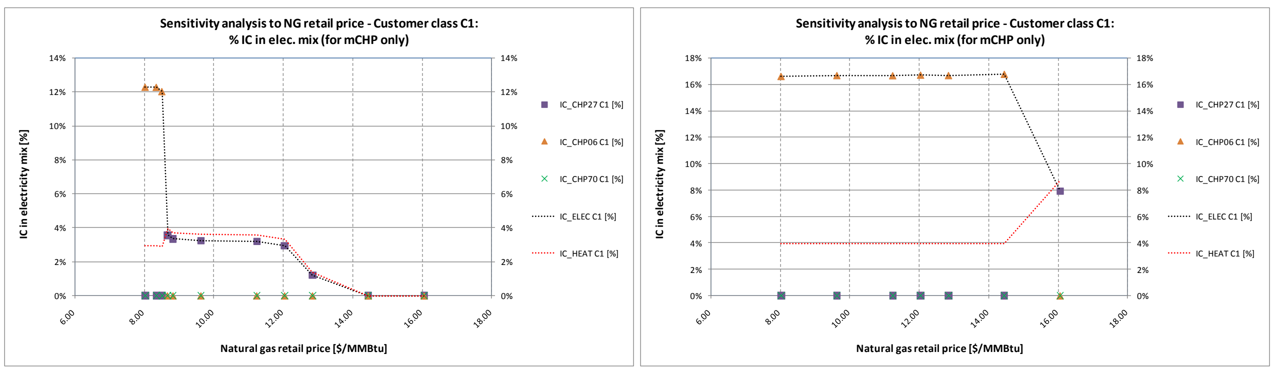


Figure C. 20: (a) Medium CO2 price & High micro-CHP capital cost, (b) Medium CO2 price & Medium micro-CHP capital cost

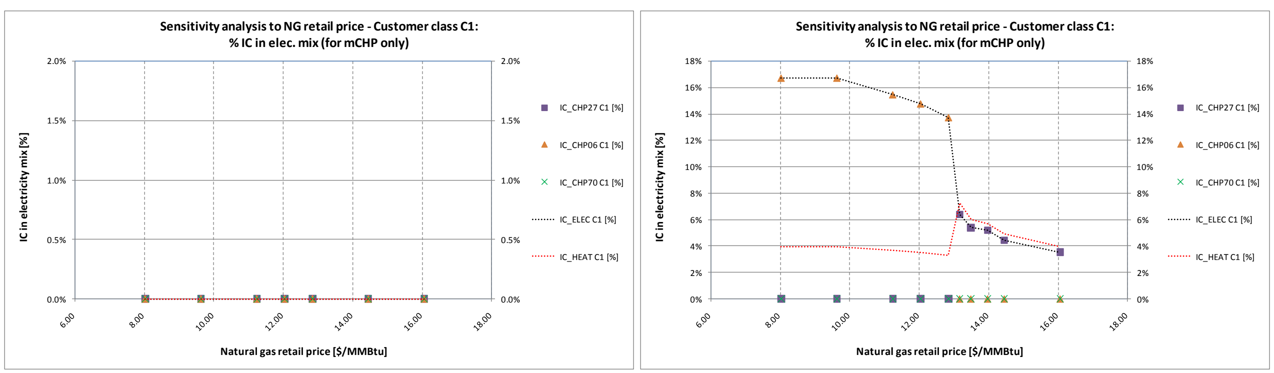


Figure C. 21: (a) No CO2 price & High micro-CHP capital cost, (b) No CO2 price & Medium micro-CHP capital cost

C.9. NG retail price sensitivity - Micro-CHP penetration per technology for customer class C2

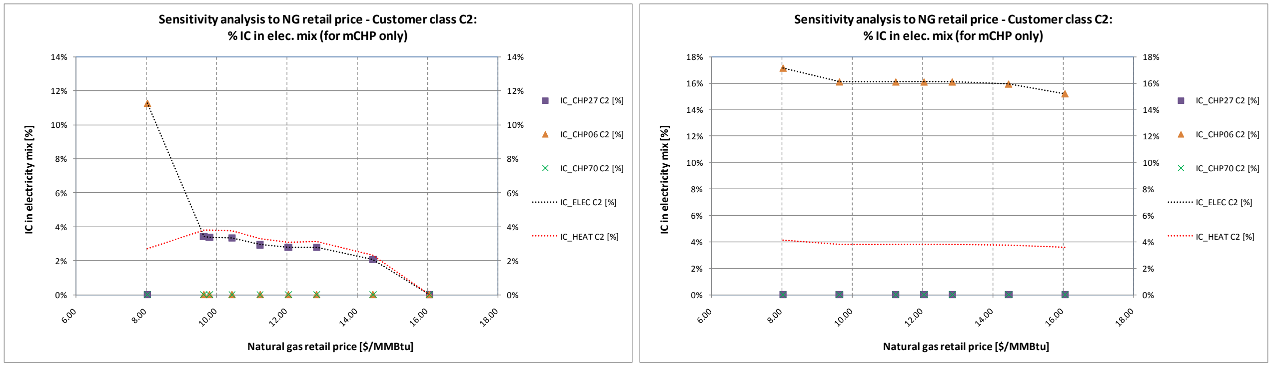


Figure C. 22: (a) High CO2 price & High micro-CHP capital cost, (b) High CO2 price & Medium micro-CHP capital cost

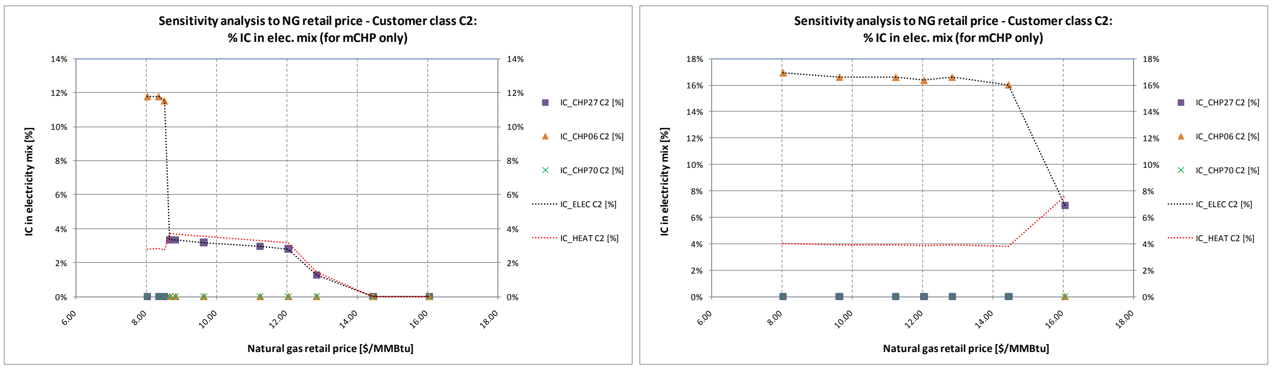


Figure C. 23: (a) Medium CO2 price & High micro-CHP capital cost, (b) Medium CO2 price & Medium micro-CHP capital cost

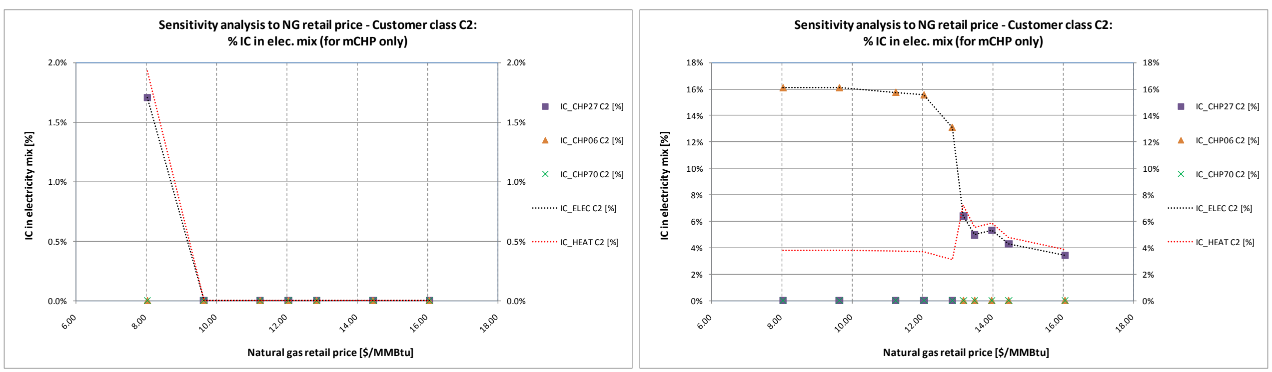


Figure C. 24: (a) No CO2 price & High micro-CHP capital cost, (b) No CO2 price & Medium micro-CHP capital cost

C.10. Long-term results for the case with no micro-CHP

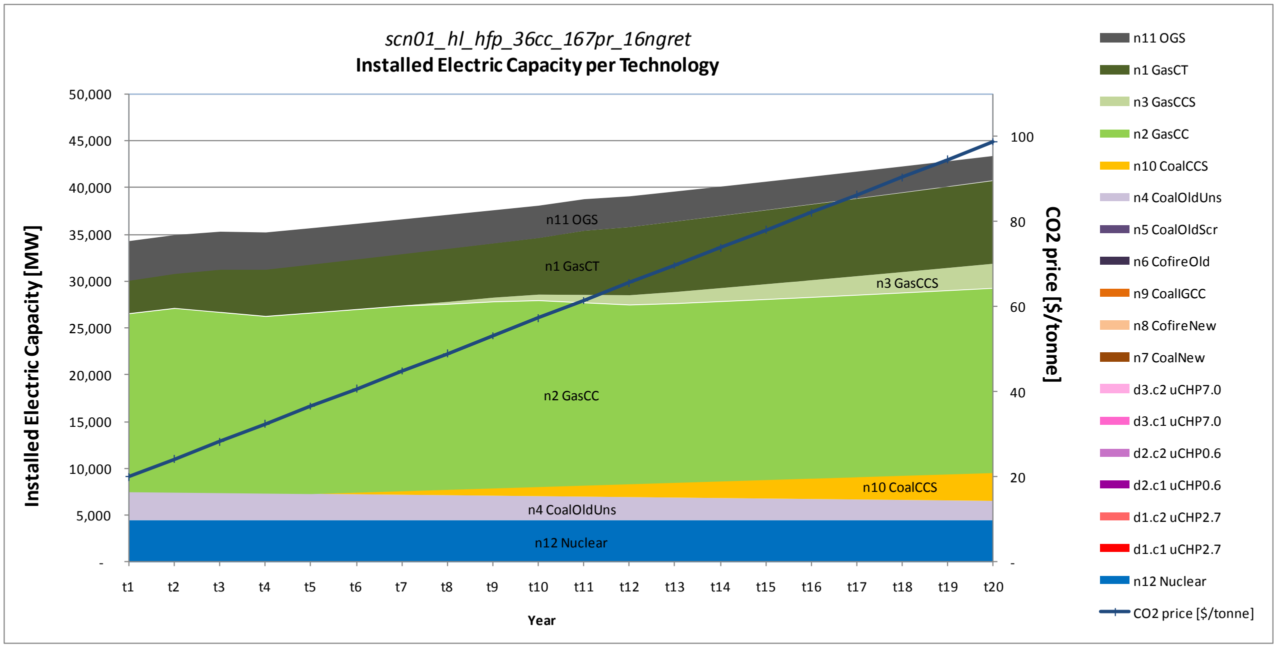


Figure C. 25 Results for the case with No micro-CHP - Electric installed capacity at every year of the time horizon for conventional generating and micro-CHP technologies

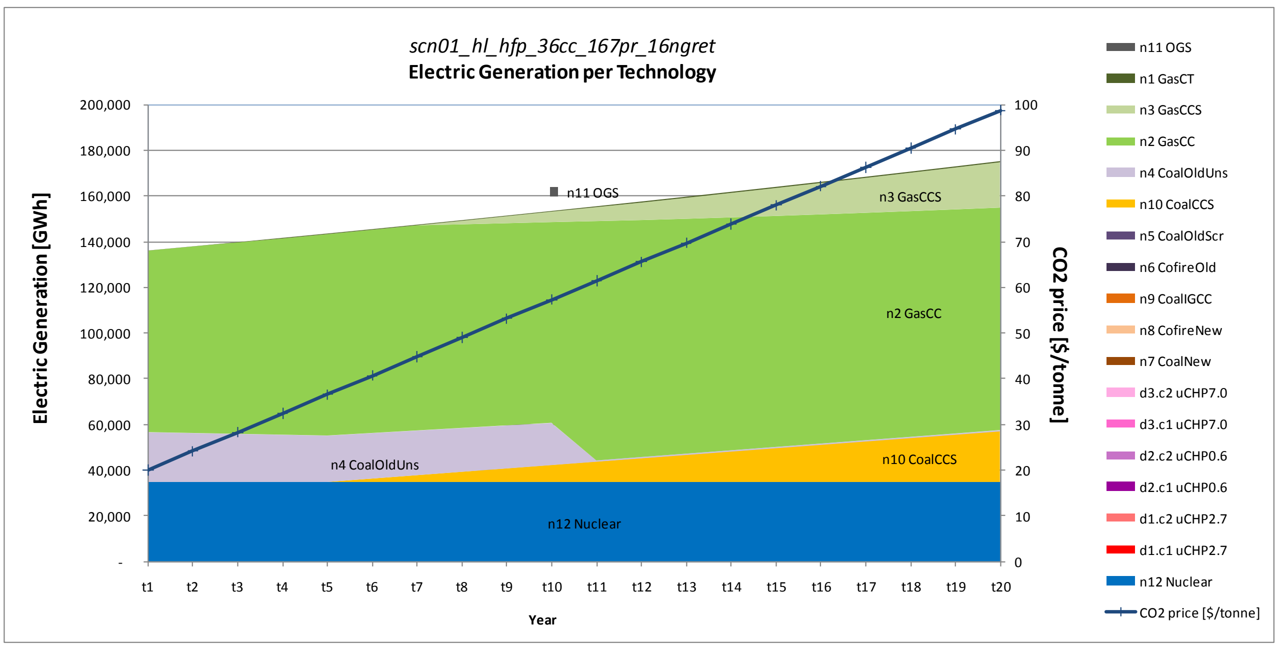


Figure C. 26: Results for the case with No micro-CHP - Electric generation for every year of the time horizon for conventional generating and micro-CHP technologies

C.11. Electric variable costs for conventional & micro-CHP technologies for year 20 – With and without CO2 price

Conventional technologies year t20	Variable cost w/o CO2 price [$/kWhe]	Variable cost with CO2 price [$/kWhe]
GasCT	**0.105**	**0.170**
GasCC	**0.070**	**0.113**
GasCCS	0.084	0.089
CoalOldUns	**0.039**	**0.131**
CoalCCS	0.044	0.054
OGS	0.172	0.251
Nuclear	0.009	0.009
mCHP2.7	0.074	0.096
mCHP0.6	0.083	0.108
mCHP7.0	0.099	0.129

Table C- 2: Variable costs per unit of electricity for conventional electric power technologies & micro-CHPs
For micro-CHP technology is included the cost with savings because of simultaneous production of heat

Micro-CHP technologies year t20	Variable cost (w/o heat savings) [$/kWhe]	Variable cost (with heat savings) [$/kWhe]	Comments
Micro-CHP2.7	**0.325**	**0.096**	
Micro-CHP0.6	*0.158*	*0.108*	*Not part of technology mix*
Micro-CHP7.0	*0.720*	*0.129*	*Not part of technology mix*

Table C- 3: Variable costs per unit of micro-CHPs including the cost with savings because of simultaneous heat production

C.12. Micro-CHP optimum size analysis for customer class C1 & C2

The *optimum micro-CHP size* is given by the relationship between the residential on-site energy loads, energy operation cost and fixed capital cost. Based on the residential operation model (HH model explained in Chapter 3) we estimated the total operational energy costs for the last year of the time period, i.e. year t20, under the particular fuel and electricity price conditions in a scenario with high CO2 price. For the sake of simplicity, we run the simulations using the heating systems without hot water tank, for every hour of the year and for each customer class.

The analysis was performed for a wide range of micro-CHP electrical outputs, from 0.5kWe up to 8kWe. Also, we explored results under continuous and discrete operation. In the second case, we worked with two cases with different discrete operational stages: 1-step discrete operation where the output could be either 0kWe or 100% of the nominal output; and 2-step discrete operation where the output could be either 0kWe or 50% or 100% of the nominal output. For example, for a micro-CHP with 1kWe nominal output, the 1-step discrete operation could be either 0kWe or 1kWe, while the 2-step discrete operation could be either 0kWe or 0.5kWe or 1kWe.

In all cases we looked at not only the *annual energy costs* because of heat and electricity, but also the *micro-CHP electric capacity factor and on-site energy efficiency*:

- Micro-CHP capacity factor (CF_{chp}) is calculated as the ratio of the electricity production output and the electricity production at full capacity during the year.
- Micro-CHP onsite energy efficiency is calculated as the ratio of energy output (electricity and heat) minus excess heat, and the total fuel used to operate the micro-CHP unit during the year.

In addition, a simple payback period for micro-CHP technology was calculated as the incremental investment cost divided by the annual energy operating savings brought by using micro-CHPs. The expression used was:

$$PB_{customerclass} = \frac{HPR_{chp} \cdot E_{chp} \cdot \left(IC_{chp} - IC_{aux}\right)}{EC_{chp} - EC_{aux}} \; [yr]$$

Where,

EC_{chp}, EC_{aux} are the total annual energy costs incurred while meeting the customer's heat load using micro-CHP and conventional heating systems respectively [$].

IC_{chp}, IC_{aux} are the micro-CHP & conventional heating equipment investment costs per units of heat respectively [$/kWth].

E_{chp} is the micro-CHP nominal electric capacity [kWe].

HPR_{chp} is the heat-to-power ratio of the micro-CHP technology [kWth/kWe].

The residential model (HH model) was run for the micro-CHP technology with HPR2.7, with varying micro-CHP electricity outputs (E_{chp}). Annual energy costs (EC_{chp}, EC_{aux}) were obtained for every size range. The unitary investment costs were assumed to be the values required to have 10% micro-CHP at the end of the time horizon in the LT model, i.e. about 4,450 [$/kWe] or 36% capital cost reduction from the 7,000[$/Kwe] reference value.

Finally, the micro-CHP optimum size per customer class was chosen from the outcomes of the 2-step discrete operation, with a payback period close to 8.5 years.

Results for Customer Class C1

Customer class 1 represents the type of households living in a 2500sqft house located in a Boston-like area. According to the LT model outcome, in order to have a 10% penetration in electric installed capacity by year t20, the technology of choice is a micro-CHP with medium HPR2.7 (for the particular residential energy loads and market conditions).

Looking at the figure below we note that, for a 2-step discrete micro-CHP operation, the minimum energy cost of 6,145[$/yr] is reached with a micro-CHP of size 1.4[kWe], with a capacity factor of about 51% and efficiency about 86%.

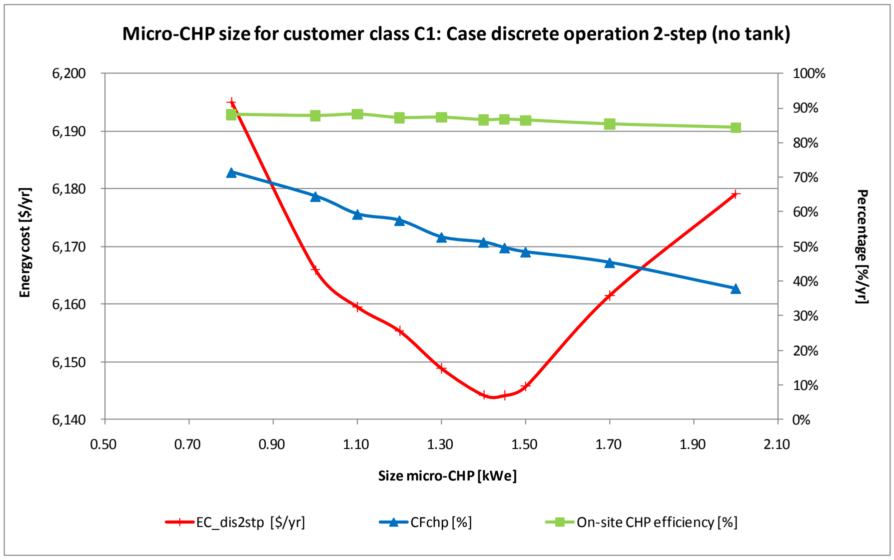


Figure C. 27: Micro-CHP size sensitivity analysis for C1 - Annual energy costs (EC), micro-CHP capacity factor (CF) & on-site efficiency under a 2-step discrete micro-CHP operation

As mentioned above, we explored how results change under discrete and continuous micro-CHP operation. Figure C.28 shows the annual energy costs for the three examined operation modes compared to the energy costs for residential customers with conventional heating systems only (without micro-CHP). Clearly we see that continuous micro-CHP operation brings the lowest energy costs up to certain size, after which the costs remain at the lowest. At present, most micro-CHP technology under commercialization has a 1-step discrete nature. However, as described in Chapter 2, some manufacturers are working to have micro-CHP with continuous operation range (but it is still under development).

For the purpose of our analyses, we chose the micro-CHP technology with a 2-step discrete operation as it is reasonable middle point between continuous and 1-step discrete operation. The minimum energy cost for a 2-step discrete micro-CHP operation of size 1.4[kWe] is 6,145[$] which is about 6.3% cheaper than the energy costs without micro-CHP.

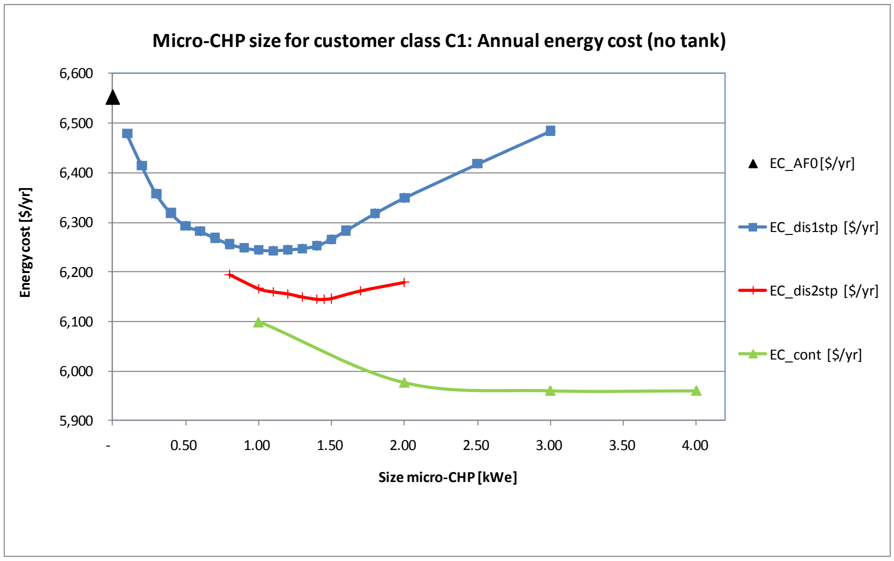


Figure C. 28: Micro-CHP size sensitivity analysis for C1 - Annual energy costs for case without micro-CHP (AF0), 1-step discrete operation (dis1stp), 2-step discrete operation (dis2stp) and continuous operation (cont)

However, *looking at only the annual operational energy costs is not sufficient to decide the optimum micro-CHP size. We also need to consider the effect of capital costs.* In Figure C.29 we plotted energy costs (*EC*) for each operational model against the payback period (*PB*) for the micro-CHP. We note that for all cases the payback period is very high, even using a unitary investment cost of 4,450[$/kWe] or 36% capital cost reduction from the 7,000[$/kWe] reference value (value required to have 10% micro-CHP at the end of the time horizon in the LT model).

Therefore, we focused on the results with payback period (*PB*) below 10 years. In particular, given that the economic life of micro-CHPs is expected to be 20 years, for the 2-step discrete operation we chose a micro-CHP size of 0.8[kWe] with a payback period of 8.5 years. For this unit size, the energy cost is 6,195[$] (i.e. 5.5% cost reduction); capacity factor is 75%; and on-site efficiency is 88%.

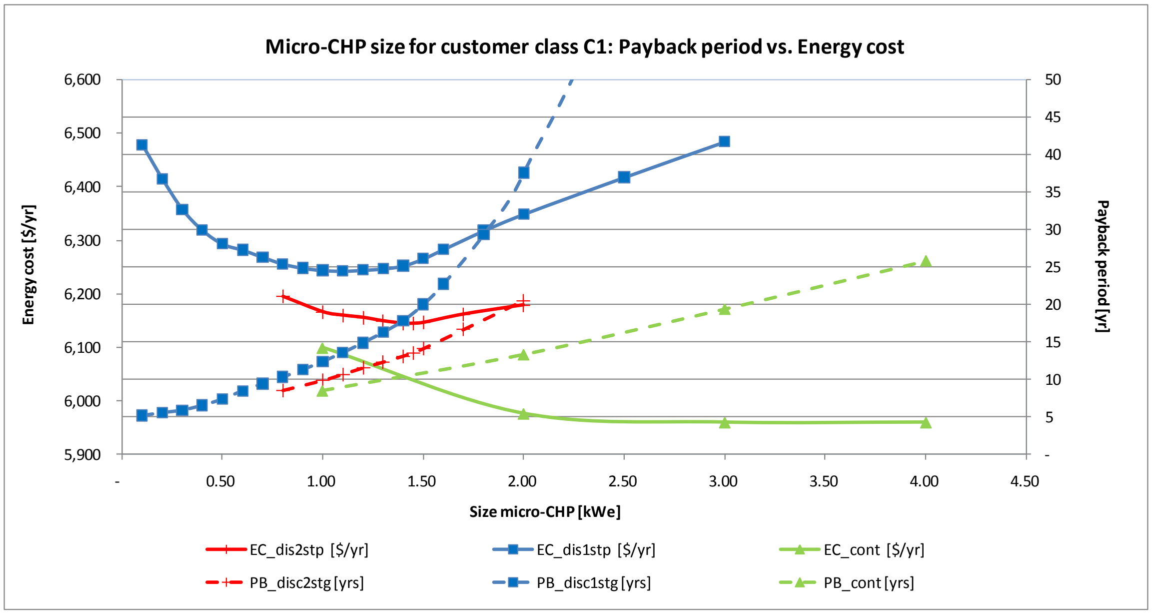


Figure C. 29: Micro-CHP size sensitivity analysis for C1 - Annual energy costs (EC) vs. Payback period (PB)
1-step discrete operation (dis1stp), 2-step discrete operation (dis2stp) and continuous operation (cont)

Finally, *from the LT model we obtained that the micro-CHP installed capacity with HPR2.7 for customer class 1 by year t20 was 2,171[MW]. Thus, with a unit size of 0.8[kW], the number of householders operating this technology would be 2,713,113 customers by the end of time period.*

Results for customer class C2

Customer class 2 represents the type of households living in a 4500sqft house located in a Boston-like area. Similar to customer class C1, in order to have a 10% penetration in electric installed capacity by year t20 (LT model outcome), the technology of choice is a micro-CHP with medium HPR2.7.

Looking at Figure C.30 we note that, for a 2-step discrete micro-CHP operation, the minimum energy cost of 9,366[$/yr] is reached with a micro-CHP of size 2.5[kWe], with a capacity factor of about 48% and efficiency about 86%.

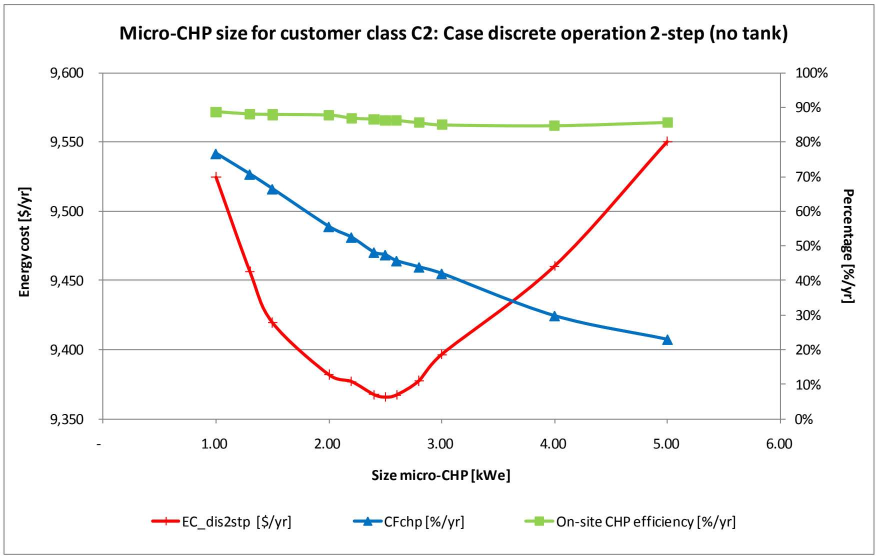


Figure C. 30: Micro-CHP size sensitivity analysis for C2 - Annual energy costs (EC), Capacity factor (CF) & on-site efficiency under a 2-step discrete micro-CHP operation

We explored how results change under discrete and continuous micro-CHP operation. Figure C.31 shows the annual energy costs for the three examined operation modes compared to the energy costs for residential customers with conventional heating systems only (without micro-CHP). Again we see that continuous micro-CHP operation brings the lowest energy costs up to certain size, after which the costs remain at the lowest.

We chose the micro-CHP technology with a 2-step discrete operation as it is reasonable middle point between continuous and 1-step discrete operation. The minimum energy cost for a 2-step discrete micro-CHP operation of size 2.5[kWe] is 9,366[$] which is about 6.8% cheaper than the energy costs without micro-CHP.

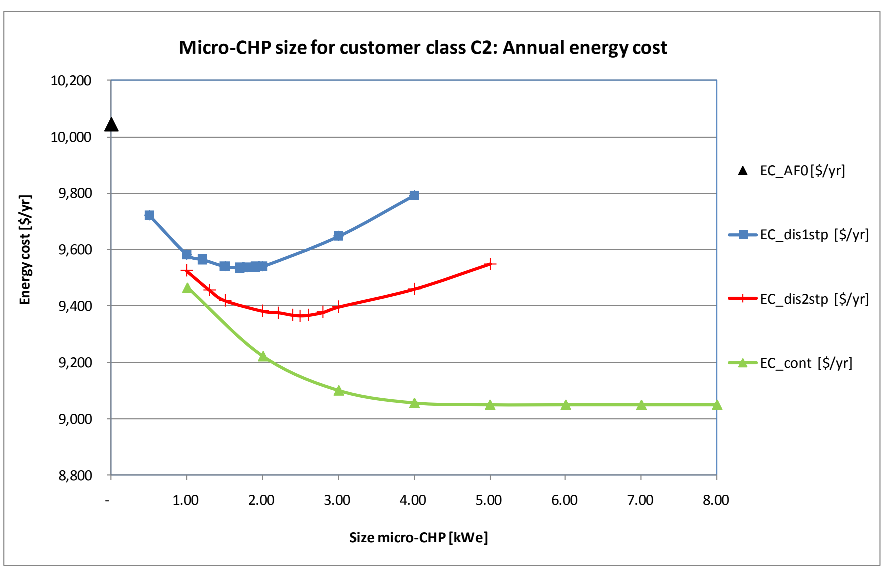


Figure C. 31: Micro-CHP size sensitivity analysis for C2 - Annual energy costs for case without micro-CHP (AF0)
1-step discrete operation (dis1stp), 2-step discrete operation (dis2stp) and continuous operation (cont)

Now, looking at the effect of capital costs, in Figure C.32 we plotted energy costs (EC) for each operational model against the payback period (*PB*) for the micro-CHP. We used a unitary investment cost of 4,450[$/kWe] (36% capital cost reduction from the 7,000[$/Kwe] reference value) to have 10% micro-CHP at the end of the time horizon in the LT model.

Results show that for a 2-step discrete operation, a micro-CHP of size 1.3[kWe] has a payback period of 8.5 years. For this unit size, the energy cost is 9,456[$] (i.e. 5.9% cost reduction); capacity factor is 71%; and on-site efficiency is 88%.

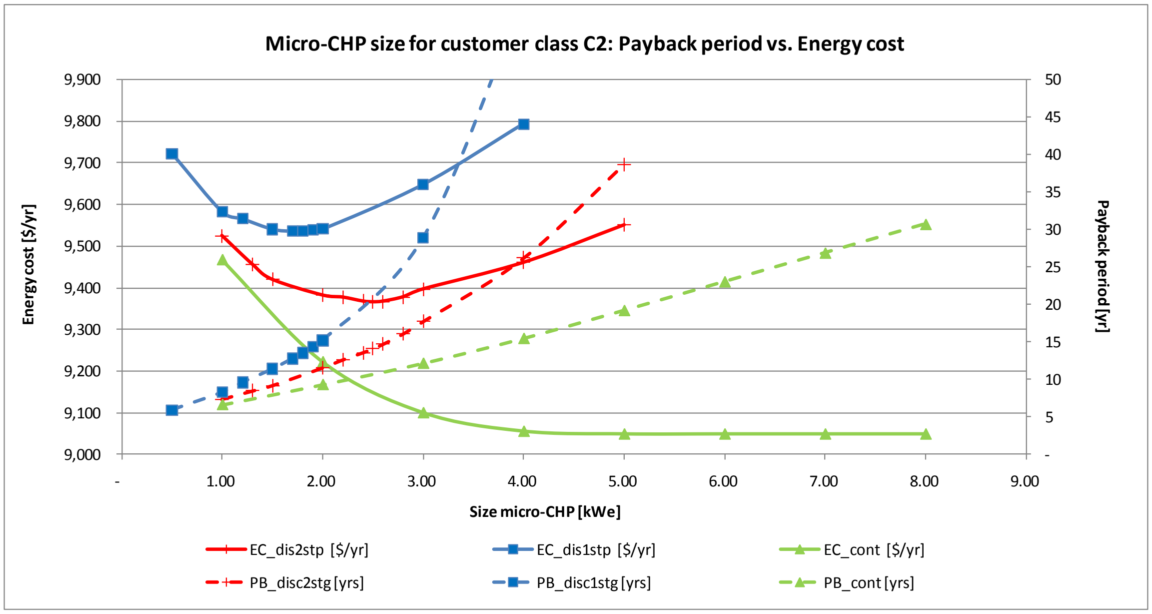
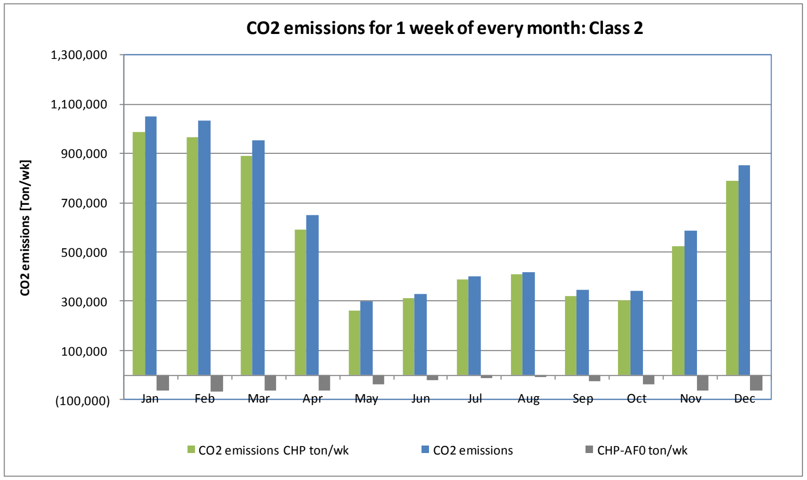


Figure C. 32: Micro-CHP size sensitivity analysis for C2 - Annual energy costs (EC) vs. Payback period (PB)
1-step discrete operation (dis1stp), 2-step discrete operation (dis2stp) and continuous operation (cont)

Finally, *from the LT model we obtained that the micro-CHP installed capacity with HPR2.7 for customer class 2 by year t20 was 2,181[MW]. Thus, with a unit size of 1.3[kW], the number of householders operating this technology would be 1,678,000 customers by the end of time period.*

C.13. Comparative results for CHP vs. AF0 cases – Customer class C2



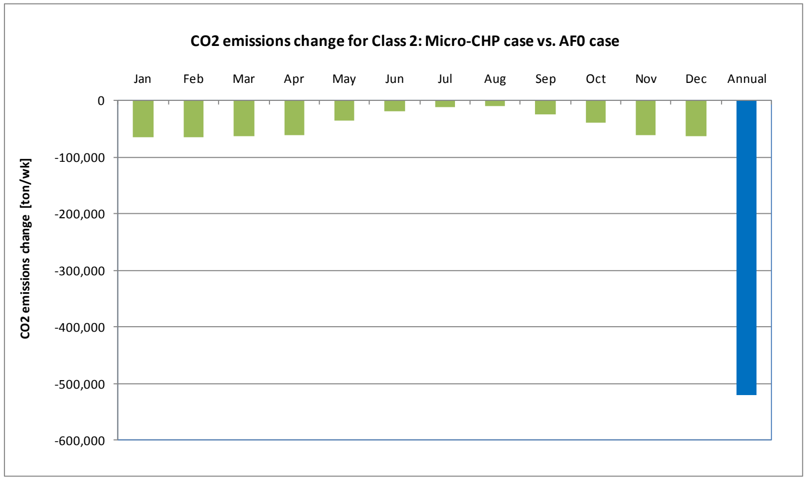
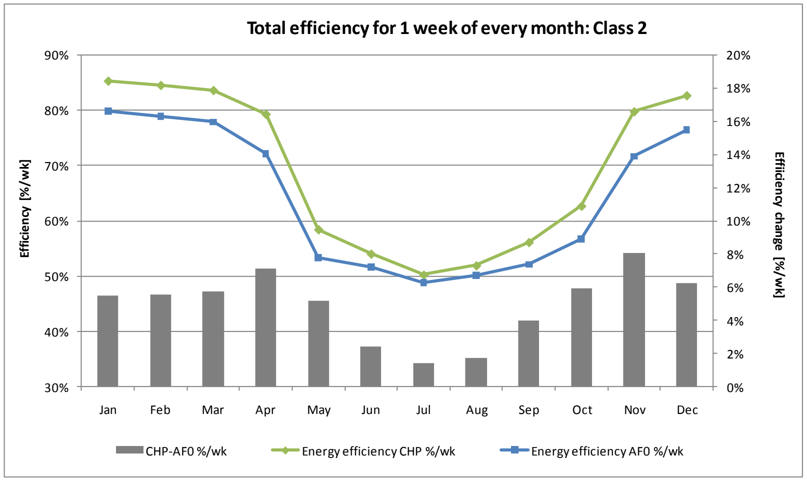


Figure C. 33: Comparative results for micro-CHP vs. no micro-CHP cases – Customer Class C2's CO2 emissions Total & Change per month



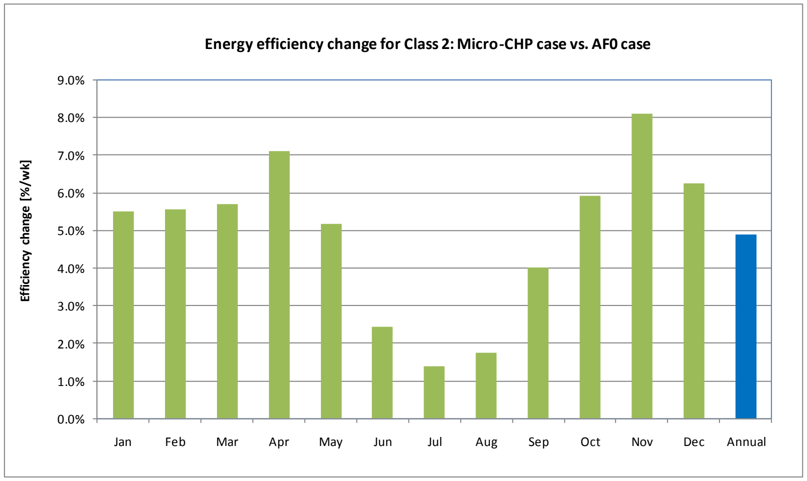
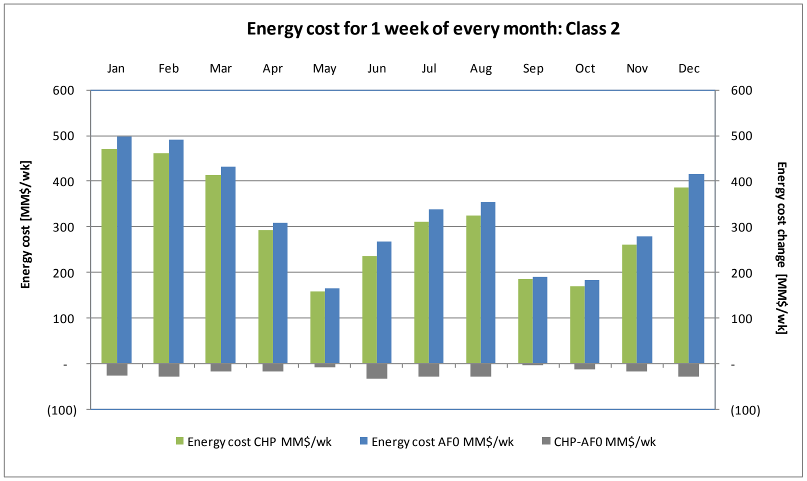


Figure C. 34: Comparative results for micro-CHP vs. no micro-CHP cases – Customer Class C2's energy efficiency Total & Change in percentage points per month



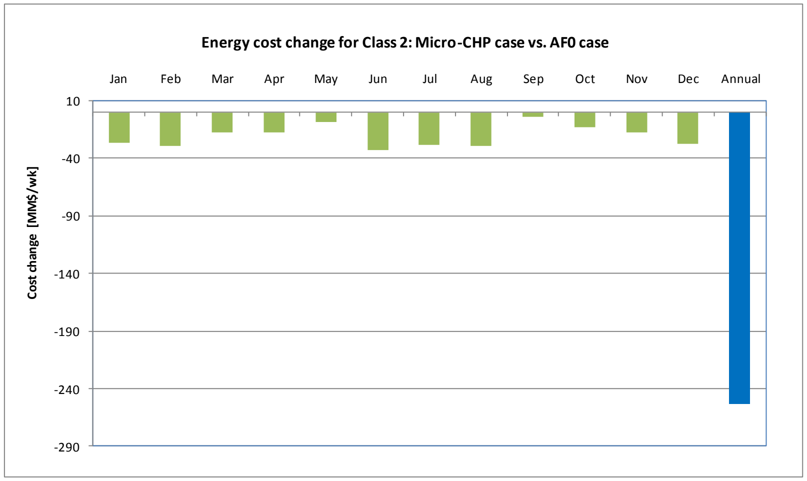
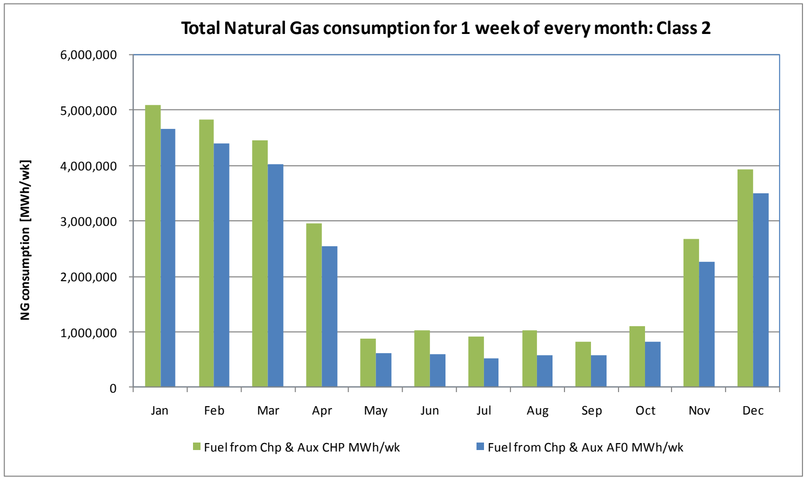


Figure C. 35: Comparative results for micro-CHP vs. no micro-CHP cases – Customer Class C2's energy cost Total & Change per month



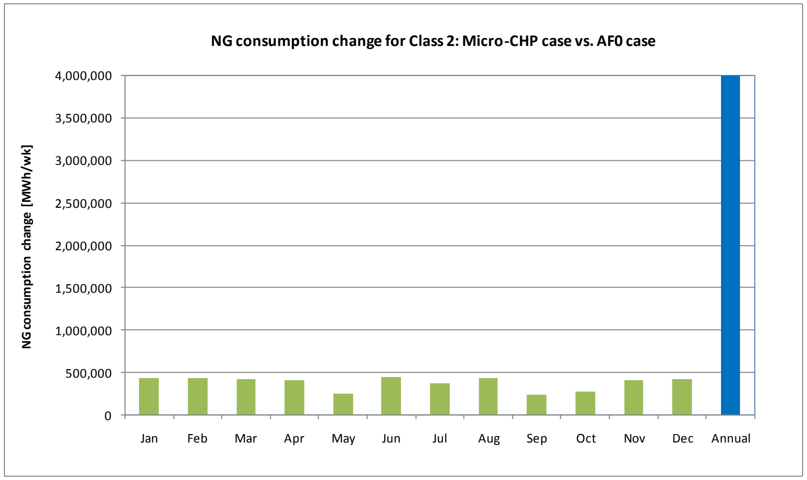


Figure C. 36: Comparative results for micro-CHP vs. no micro-CHP cases – Customer Class C2's NG consumption Total & Change per month

C.14. Micro- CHP case vs. AF0 case: Results for 1 week in Winter/February

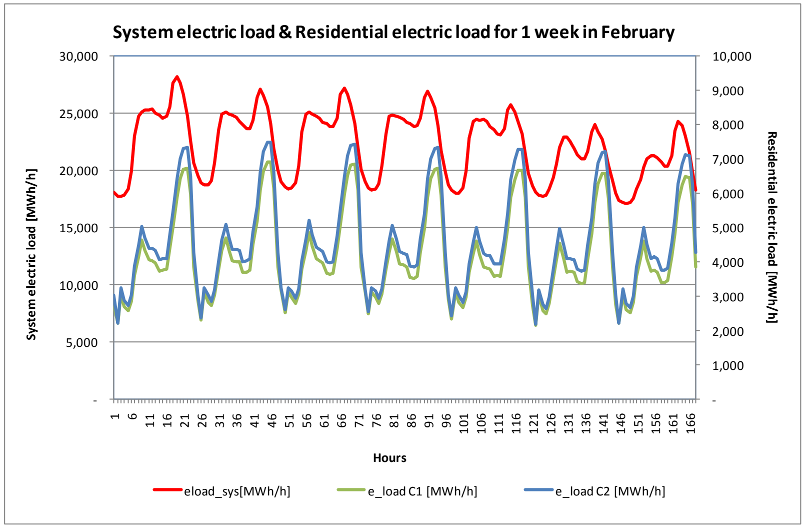


Figure C. 37: System & Residential hourly electric loads for 1 week in February

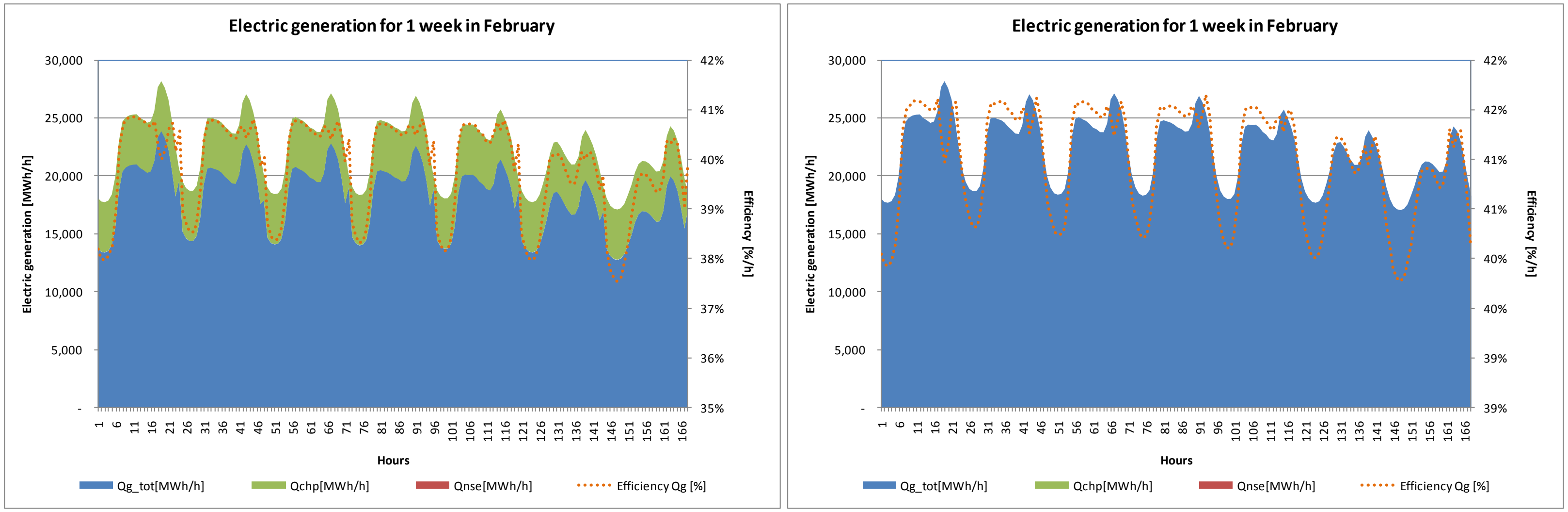


Figure C. 38: Comparative results for micro-CHP vs. no micro-CHP cases - Hourly electric production & electric efficiency for 1 week in February

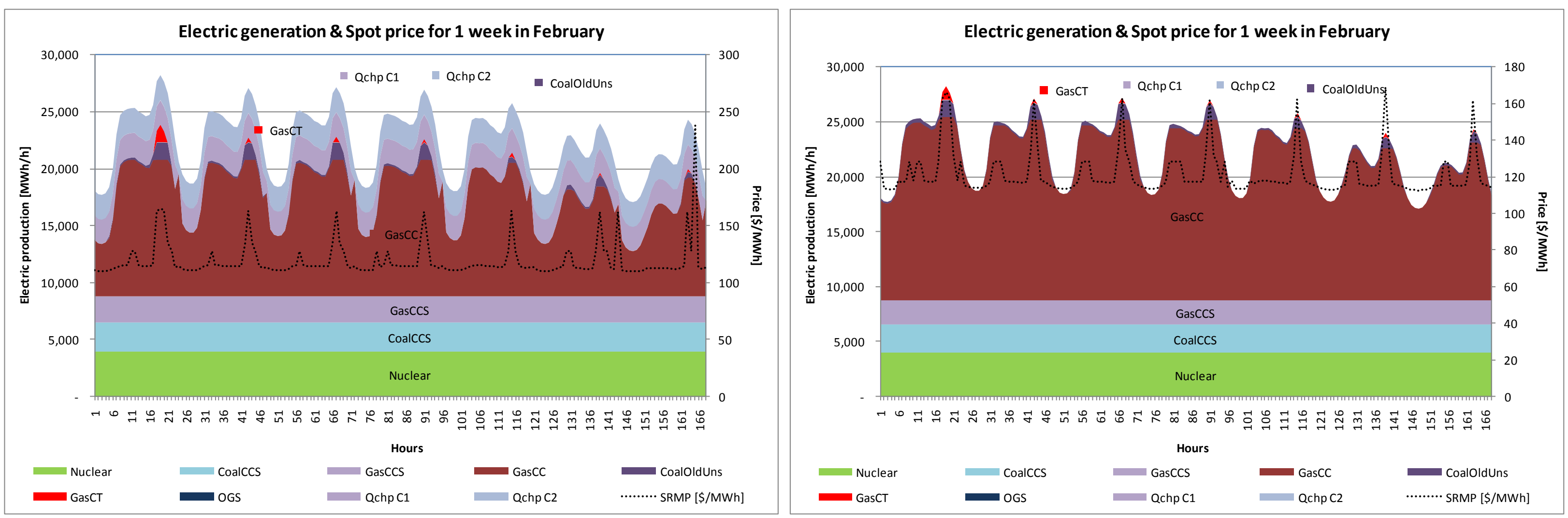


Figure C. 39: Comparative results for micro-CHP vs. no micro-CHP cases - Hourly electric production per technology & electric spot price for 1 week in February

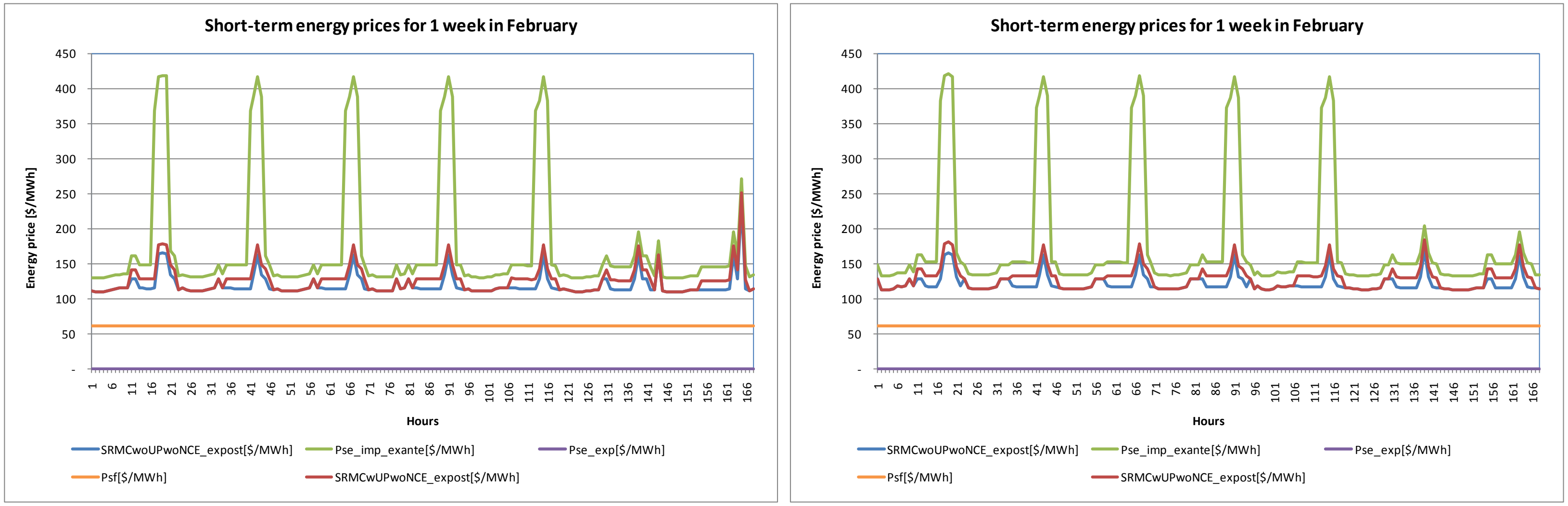


Figure C. 40: Comparative results for micro-CHP vs. no micro-CHP cases - Hourly short term energy prices for 1 week in February

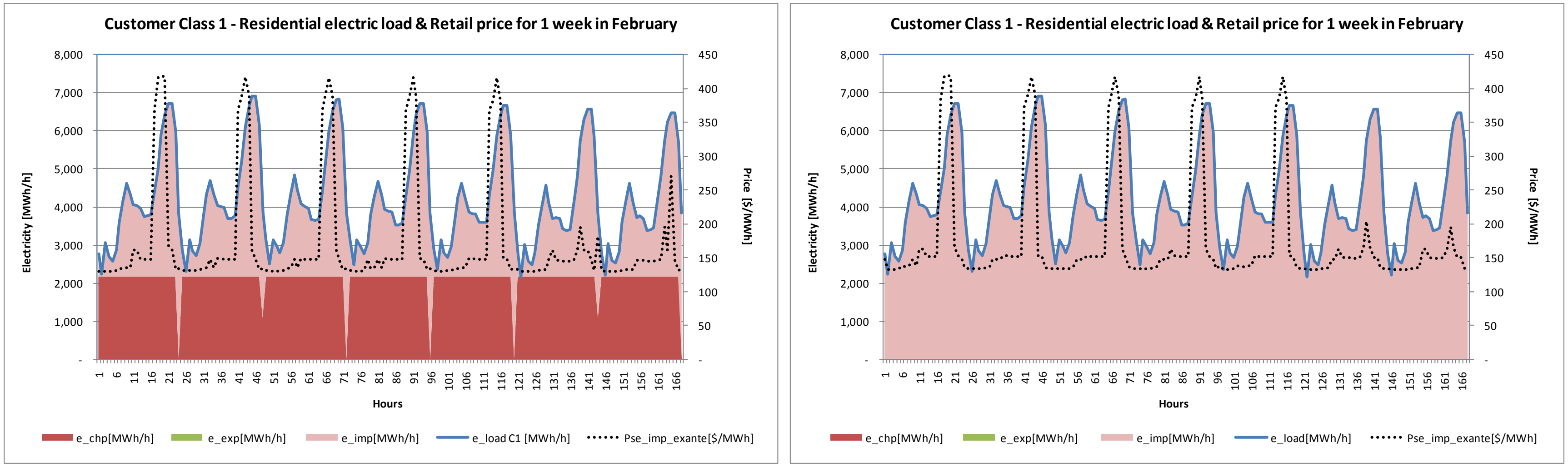


Figure C. 41: Comparative results for micro-CHP vs. no micro-CHP cases - Hourly electric load, micro-CHP generation & retail price for 1 week in February for Customer C1

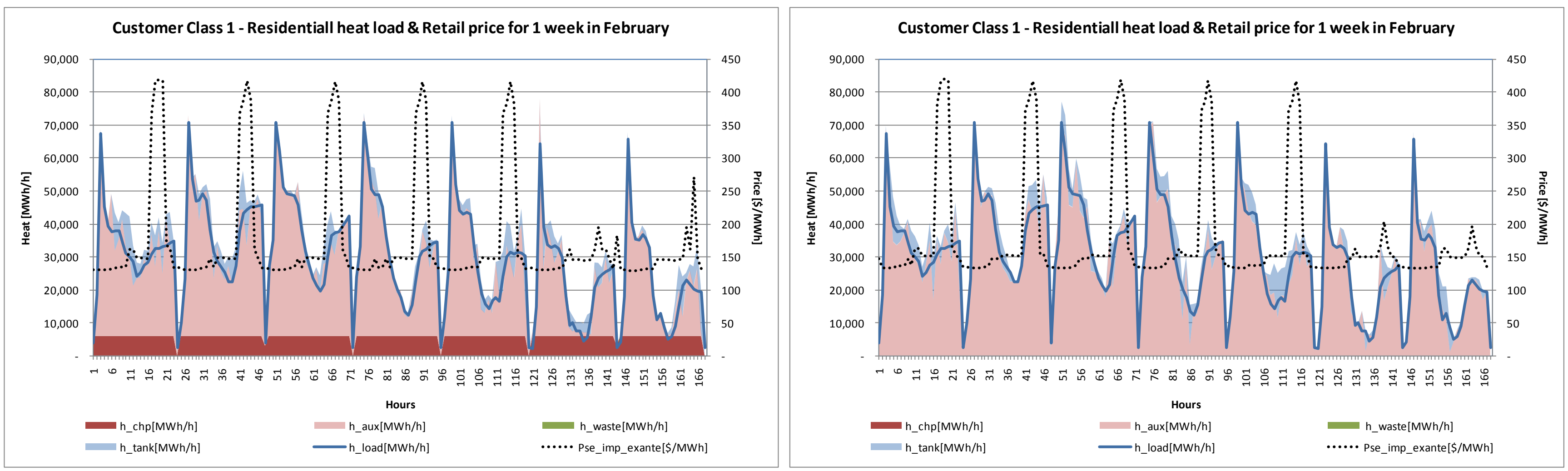


Figure C. 42: Comparative results for micro-CHP vs. no micro-CHP cases - Hourly heat load, micro-CHP generation & retail price for 1 week in February for Customer Class 1

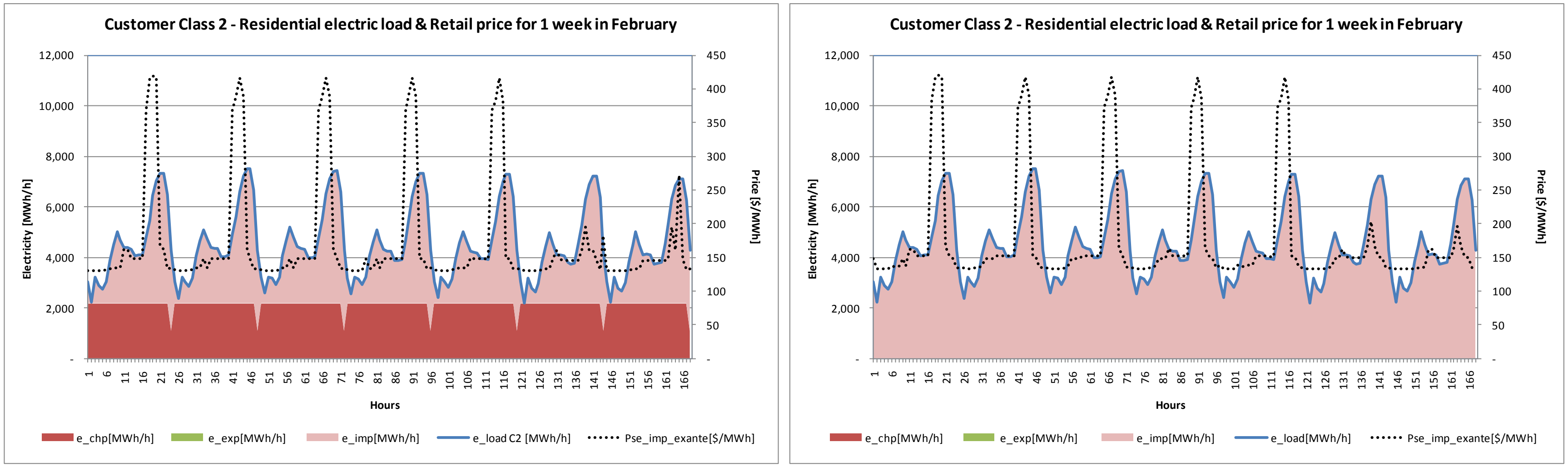


Figure C. 43: Comparative results for micro-CHP vs. no micro-CHP cases - Hourly electric load, micro-CHP generation & retail price for 1 week in February for Customer C2

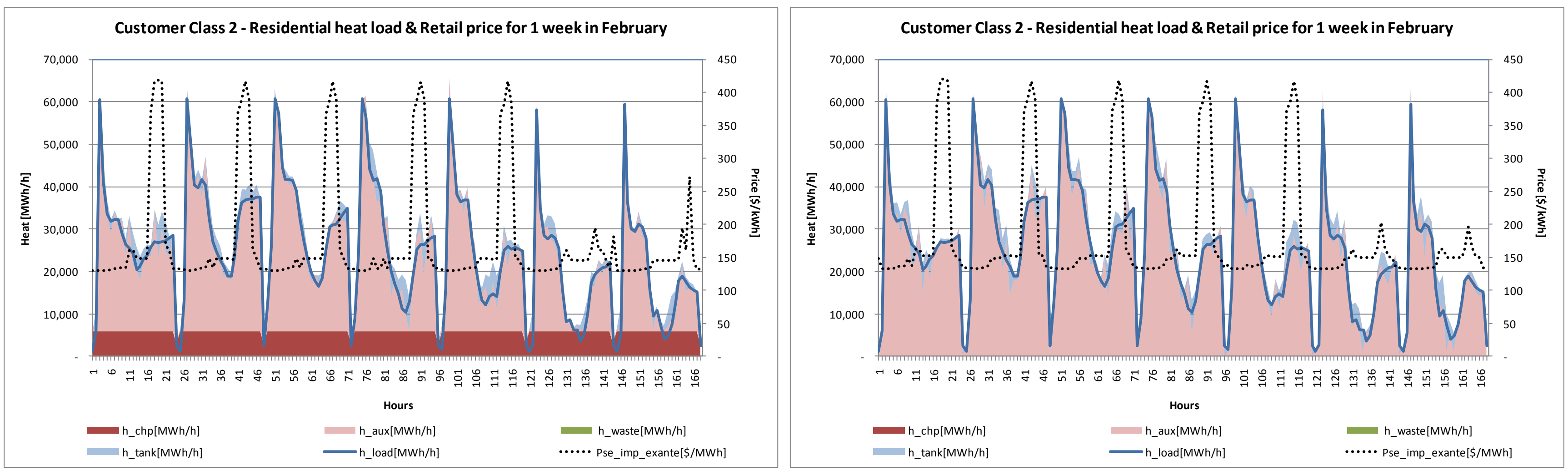


Figure C. 44: Comparative results for micro-CHP vs. no micro-CHP cases - Hourly heat load, micro-CHP generation & retail price for 1 week in February for Customer Class 2

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