AALBORG UNIVERSITY, AALBORG, DENMARK

Techno-economic Feasibility of CHP Plants Equipped With Thermal Storage in Ontario, Canada and their Conversion to Trigeneration Plants Using Absorption Chillers

M.Sc. Thesis in Sustainable Energy Planning and Management Semester 4

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Table of Contents

Chapter 1: Introduction

Electrification began in Ontario, Canada in 1910 in the city of Kitchener. The project was set up by the Hydro-electric Power Commission of Ontario, the world's first publicly owned electrical utility company. During this early period of electrification Ontario's generation capacity consisted solely of hydro-electric power. A government mandate was issued to ensure the electrification of rural regions of southern Ontario starting in the 1920's leading up to WWII. During this period significant investment was made on transmission infrastructure enabling the spread of electricity which caused an increase in demand throughout the southern regions of the province. This growing demand exceeded the supply capacity of the Power Commission, who as a result had to purchase imported hydro-electricity from the neighbouring province of Quebec. (Fleming, 1991) (Ministry of Energy, 2010) (Historica-Dominion Institute, 2011).

During the post-war economic boom the demand for electricity continued to increase, causing the provincial utility company to diversify its supply mix through the creation of central thermal power plants fired by fossil fuels such as coal. By the 1960's Ontario's utility company had decided that nuclear power was the appropriate generation technology to meet future demands for electricity and proceeded to build a number of nuclear reactors. The first of which was opened at Douglas Point in 1966 (Ministry of Energy, 2010).

During 1974 the Hydro-electric Power Commission of Ontario was recognized as a crown corporation owned by the province and was renamed Ontario Hydro. During this period leading up until the 1990's Ontario's electricity supply mix remained unchanged (Ministry of Energy, 2010).

Due to the system remaining virtually unchanged for approximately 2 decades, growth of the electricity sector began to stagnate in the 1990's. Between 1996 and 2003 the demand for electricity was still increasing while the installed generation capacity was decreasing. There was a lack of investment in new generation capacity, transmission and distribution infrastructure and conservation/demand management programs. These were all contributing factors that led to the passing of legislature in 1998 that authorized the creation of a deregulated electricity market and ultimately, to the disaggregation of the crown corporation Ontario Hydro into 3 independent entities. Following the break-up of Ontario Hydro more than 20 billion dollars of debt was stranded and left to be paid by the province's electricity consumers (Ministry of Energy, 2010) (Historica-Dominion Institute, 2011).

Following the disaggregation of Ontario Hydro, market deregulation occurred. Initially deregulation of the electricity market was unsuccessful as the market price for electricity rose by over 30% in less than a year due to the shortage of new supply and also reliance on the import of foreign coal from the United States (Ministry of Energy, 2010). The Ontario system faced further complications during the 2003 black-outs that originated in Akron, Ohio, USA. Both of these issues highlighted the need for increased investment in the electricity system to ensure quality power was supplied to Ontario's consumers into the future. (Dubinsky, 2011)(Ministry of Energy, 2010)

From the period of 2003 to 2010 Ontario made significant improvements to the electricity system including renewing 5000 km of transmission infrastructure, increasing and diversifying generation capacity, refurbishing existing nuclear reactors, increasing renewable electricity generation

capacity through creation of the green energy and green economy act, and reducing peak electricity demand and annual consumption through government funded conservation and demand management programs (Ministry of Energy, 2010). The province has also been able to make the transition from being a net importer of electricity to a net exporter (Dubinsky, 2011).

Although significant improvements have been made to the electrical system in the last decade, there are significant issues that need to be addressed going into the future. In order to address these issues Ontario's Ministry of Energy have published a long-term energy plan this year that illustrates how the province will progress into the future and meet forecasted electricity demands and ambitious greenhouse gas emissions reductions targets up until 2030. The key goals of the new plan include:

- Removing coal from supply mix by 2014
- Refurbishing existing nuclear reactors
- Creating two new nuclear reactors
- Converting existing coal plants to biomass or natural gas
- Increasing hydroelectric capacity (Niagara Falls extension, Lower Mattagami Project etc.)
- Increasing renewable energy capacity through 2009's Green Energy and Economy Act's Feed-In Tariff Programs
- Reducing demand through government funded conservation and demand management incentive programs
- Increasing small scale (<20MWel) distributed CHP projects through a "standard offer program" if they can be found to be feasible from a technical, economic and geographical perspective

(Ministry of Energy, 2010)

Following release of the long-term plan, there has been some doubt cast on its ability to meet future demand and also some opposition to the increased costs that it will impose. Doubts regarding whether the plan will meet future demand have arisen due to the change in provincial policy, restrictions on grid connections for renewable energy projects and due to uncertainties surrounding the future of the Darlington nuclear plant.

The change in provincial energy policy that has created doubts placed a moratorium on the development of any future Off-shore wind turbines in fresh water lakes until future environmental assessments have been completed (Some of which have already been provided contracts through the green energy and green economy act's feed-in tariff program) (Spears, 2011a). Many of the renewable energy projects that have been given contracts through the green energy and green economy act's feed-in tariff program are still waiting to become grid connected due to a lack of transmission capacity required to accommodate the added generation (Spears, 2011b), and also because the Canadian Association of Environmental Law have denied Ontario Power Generation's permit to build new nuclear reactors at the Darlington site citing that "Ontario Power Generation

have not submitted an adequate environmental impact statement" for the proposed reactors and that the government would not allow any new reactors to be considered until all alternatives have been investigated (Spears, 2011c).

Opposition to the plan has also emerged due the increase in costs it will impose on Ontario consumers. Due to the costs of subsidizing renewable energy projects through the feed-in tariff program, the costs of creating new and refurbishing existing generation capacity following the decommissioning of all the coal-fired plants, and the costs of creating new and refurbishing existing transmission and distribution infrastructure, Ontario consumers can expect an increase in the price of electricity equalling 46% by 2015 (Dubinsky, 2011). This increase in price is seen as unacceptable to some consumers as the province is still paying off the debt stranded by Ontario Hydro in the form of a Debt Retirement Fee on their monthly invoices. In contrast, proponents of the plan state that electricity is extremely underpriced in the Ontario market in comparison to other developed regions such as the E.U. due to an abundance of cheap hydro-electric power and also due to the lack of carbon emissions taxation.

Regardless of whether individual consumers or parties agree or disagree with the direction in which the plan takes, there a number of issues that all parties can agree upon. These issues include the fact that the province will still require significant upgrades to the transmission system and generation capacity moving forward (Chung, 2011). There are also significant costs associated with moving away from an energy system that utilises coal to one with an increased amount of renewable generation capacity (Dubinsky, 2011). As a result, in the opinion of the author, the key to the success of this energy plan is choosing the appropriate mix of technologies for generating electricity that are technically appropriate to meet future goals in the most economically feasible manner.

While the plan does have a large mix of different technologies, the technology that plays the smallest role in terms of planned future installed capacity is Combined Heat and Power (CHP). The planned future capacity of CHP is a total of 1000 MWel (Ministry of Energy, 2010). However, when compared to other countries with a high demand for heat and progressive energy policy such as Denmark or Germany, this is a very small amount (OPA, 2010). CHP and trigeneration projects offer a number of technical, economic and environmental advantages in comparison to many other electricity generation technologies. The technical advantages include the ability to ramp up and down power production quickly in order to regulate frequency and voltage of the grid, enabling them to accommodate increasing amounts of intermittent renewable capacity into the system and they can be connected directly to the distribution system reducing transmission losses (Anderson and Lund, 2007) (OPA, 2011). The economic benefits include additional revenue through sale of heat and electricity, reduced vulnerability to fluctuations in fuel prices, reduced costs associated with upgrading the high voltage transmission network because they can be connected directly to the distribution system, and reduced fuel costs due to reduced losses (OPA, 2011). The environmental advantages include a reduction in greenhouse gas emissions when comparing equal amounts of heat and electricity produced in a decoupled manner (Ministry of Energy, 2010).

As a result, the purpose of this research is to determine the techno-economic feasibility of small scale (<20MW) distributed CHP in Ontario, Canada. The results can then be utilised as a case for or against the investigation of CHP as a means to reduce resource consumption and emissions while meeting future demand for electrical and thermal energy in other geographic locations of Ontario.

A secondary objective of this research is to determine whether it is technically and economically feasible to convert an optimised CHP plant to a trigeneration plant in order to meet cooling demands as well as heating demands.

Two reference scenarios for natural gas boilers plants with differing efficiencies will be compared to an alternative scenario where CHP equipped with thermal storage is introduced. Through this comparison the optimal size of CHP plant can then be identified.

In order to determine whether it is economically feasible to convert a CHP plant to trigeneration a new reference scenario will be constructed that is composed of the optimised CHP plant from the first alternative scenario and introduces a cooling demand met by electrical chillers. The second alternative scenario will compare the reference system with electrical chillers to a trigeneration system that employs absorption chillers.

Chapter 2: Methodology

Description of Methods to be Utilised

This chapter is defines the structure of the project and also the methods utilised in order to answer the research question.

The purpose of this report is to determine the techno-economic feasibility of CHP plants in the Toronto, Ontario, Canada and to identify the optimal size of a CHP and thermal storage tank selling electricity in the Ontario Spot Market.

In order to accomplish this goal a secondary literature review will be required in order to create a context for the problem and define the existing structure of the electricity system in Ontario, Canada. The literature review will focus on providing relevant background information about Ontario's existing electricity system, energy mix, existing market on which electricity is traded, and the current rate of employment of CHP in Ontario.

Two different forms of primary analysis will be completed. The first analysis will be in the form of a techno-economic feasibility study. This analysis is required in order to determine whether CHP plants are a profitable investment when operating under the current Ontario market conditions. In order to carry out this feasibility study an appropriate modeling tool and data will be required to determine the potential revenue and net present value associated with investing in CHP plants equipped with thermal storage tanks. This will be done by calculating the net present value of various combinations of CHP and accompanying thermal storage capacities in order to determine the optimal sizes that provide the highest profits. The analysis will determine whether the additional revenue gained from electricity sales makes it more profitable to operate a CHP with a thermal storage in comparison to a boiler only. The second analysis involves calculating the techno-economic feasibility of converting the optimal CHP plant to a trigeneration plant using absorption chillers. The techno-economic feasibility study will be conducted using the modelling software energyPRO.

Sensitivity Analysis will also be incorporated into the techno-economic feasibility study to see how fluctuating discount rates, fuel prices and wholesale electricity market prices impact the techno-economic feasibility and optimal sizes of CHP plants and thermal stores.

Temperature data, technical data and economic data will be required in order to complete the techno-economic feasibility study. The temperature data is utilised to adjust the heating and cooling demand profiles depending on the outdoor ambient air temperature. The technical data required are the electrical and thermal efficiencies of the various energy conversion units and the district heating network losses. The economic data required will be the hourly Ontario spot market price for electricity, the initial investment costs for the energy conversion units and the thermal storage tank, fuel costs (natural gas), start-up costs for the CHP and the annual operation and maintenance costs.

The energyPRO Modeling Software Tool

The energyPRO software package is a deterministic input/output model created for the purpose of techno-economic feasibility analysis of various energy projects. The model has the ability to optimise operations of a power generation, cogeneration or trigeneration project using technical and financial parameters. The calculations are carried out in steps or time intervals defined by the user (e.g. half-hourly or hourly steps) for the period being analysed.

The input parameters used in the model are demands for electricity and/or heating and cooling, fuel types, specifications of the production units (i.e. types of production units and thermal storages), the operation strategy, costs information and electricity market information such as variations in prices (spot market prices or tariff prices) paid for each unit produced.

The output generated by the model includes an optimised operation schedule based on the selected operation strategy, operation income, monthly cash flows, income statements, balance sheets, emissions reports and economic calculations such as net present value, internal rate of return and payback time.

The energyPRO model was selected for this analysis as is enables the optimisation of the production of electricity in order to realize maximum profit, while supplying the existing heating demand in the most cost effective way possible.

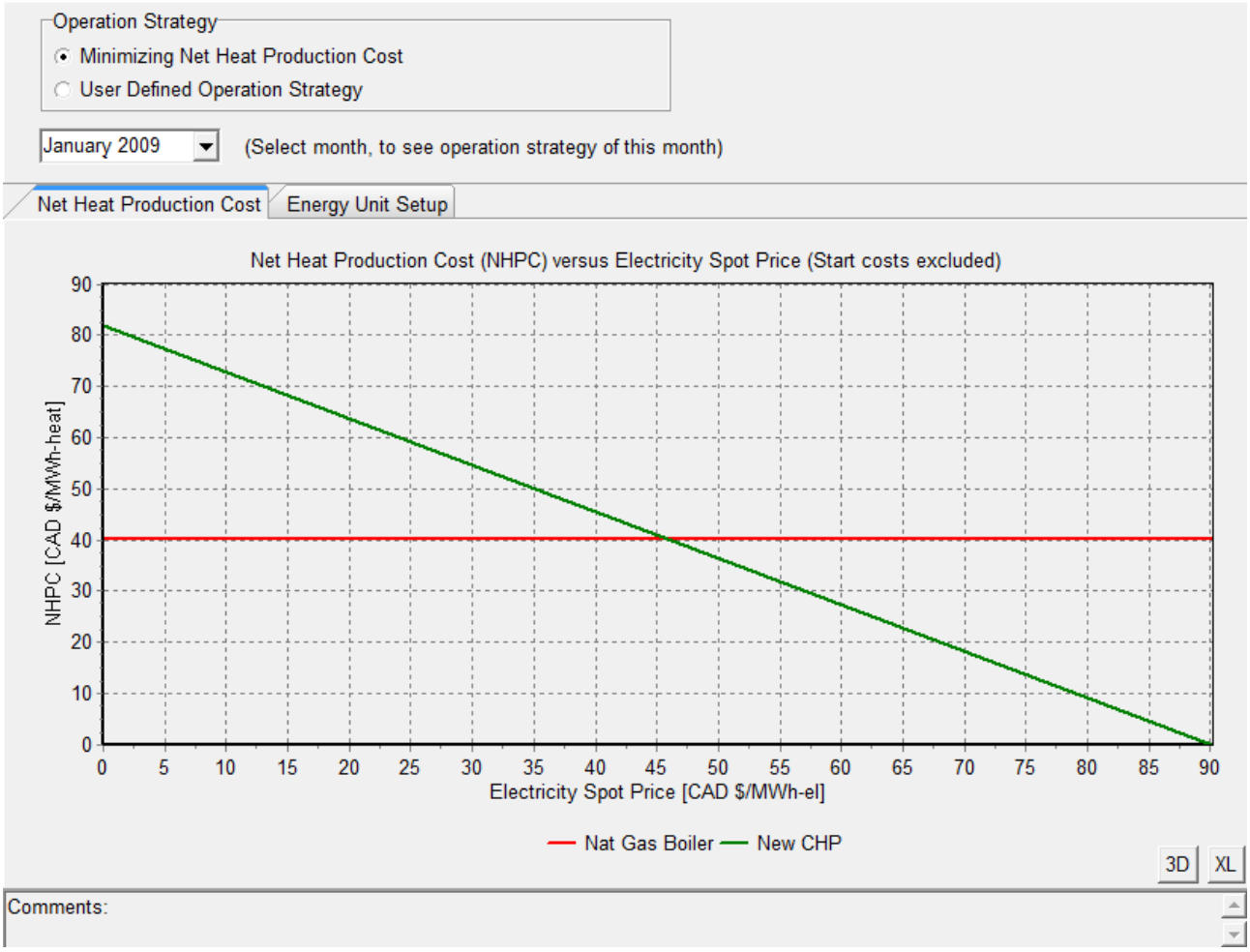
Operation Strategy Used for Optimisation of CHP Plants in energyPRO

The operation strategy selected for this study is one that is preset in the energyPRO model and allows you to minimize the net heat production cost while maximising energy sales by only producing electricity when the wholesale price is sufficiently high enough to reduce the net heat production cost below that of the running the peak load boiler alone. This is illustrated in the figure 1 ”Net heat production cost versus electricity spot price” using two curves.

In this example, the red curve is the cost of operating the boiler, which remains constant as it can only consumes natural gas to produce heat. The green curve illustrates how the cost of producing heat using a 5 MWe electric CHP unit decreases as the spot market price for electricity increases. The spot market price that corresponds to where the two curves intersect is the threshold value at which it becomes economic to operate the CHP unit rather than the boiler. The model will operate

in this manner, running the CHP when the spot market price exceeds approximately $45 CAD, otherwise it will utilise the cheaper boiler to meet the heat demand.

Figure 1. Net heat production cost versus electricity spot price



On the second tab it titled “Energy Unit Setup” it also indicates that the CHP unit will be allowed to produce heat for storage in the thermal store, however, it cannot run at partial load. The opposite is set for the peak load boiler where it can operate at partial load, however, it cannot produce heat for storage. This allows for the model to calculate the most flexible operation strategy where the CHP unit will produce electricity when the spot market price is above the threshold value to cover the current heat demand and to fill the thermal store. During times when the spot market price is below the threshold value, the thermal store will be used to meet the heat demand until its capacity has been fully utilised and then the more expensive peak load boilers will be used. This method also allows for the boiler to operate concurrently with the CHP in order to make up any peak heat demand that the CHP unit is unable to meet alone at any given time. As a result we have a system that is very flexible and ensures the lowest costs while meeting the required heat demand. This is illustrated in the figure 2.

Figure 2. Operation for the week of May 25th, 2009.

In figure 2 we can see that there is four separate graphs:

- The top graph illustrates the spot market price fluctuations throughout this week of operation (May 25 to June 1, 2009) an also shows when the price is above or below the threshold value for running the CHP unit (red is below and green is above).

- The second graph illustrates the heat demand and which units are meeting that demand. The red portions are the peak load boiler while the green is the 5 MWe CHP unit. It can clealry be seen that the CHP unit only runs when the spot price is above the threshold value with the exception of when the price drops for short periods of time as we have stipulated in the model that the CHP unit must run for a minimum of 3 hours in order to

minimize unnecessary start up costs. This is illustrated in the hours from 08:00 to 12:00 on Tuesday the 26th of May and again during the hours of 12:00 and 18:00 on Saturday the 30th of May. This graph also shows periods of peak heat demand where both the boiler and the CHP unit are operating concurrently as the heat demand exceeds the 5 MW capacity of the CHP unit and the thermal storage is empty. This is illustrated for a short period

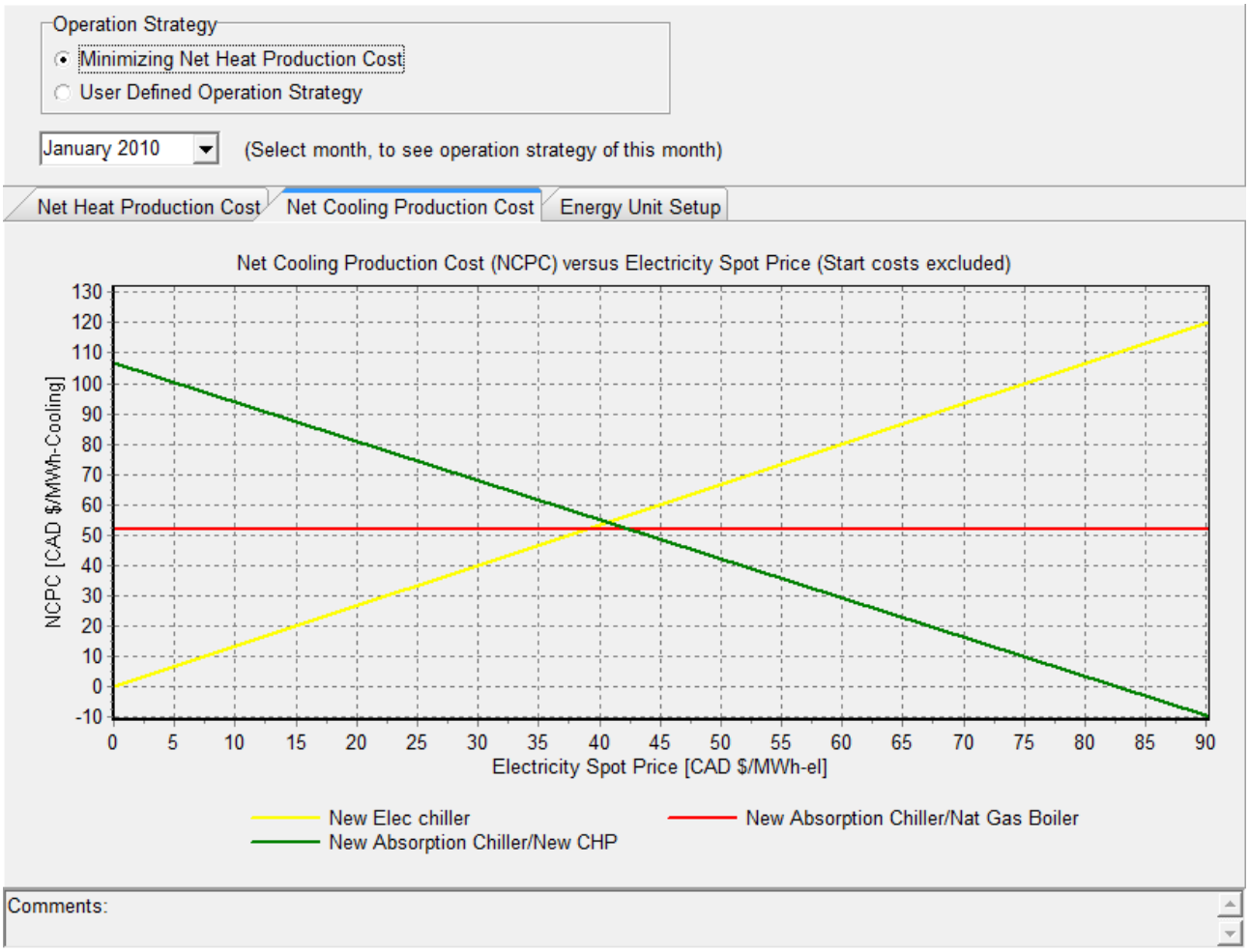
- The fourth graph indicates the amount of energy stored in the thermal store. It can be seen that when the heat production from the CHP unit exceeds the heat demand, the thermal store begins to fill up. This continues until it is full or until the spot market price falls below the threshold value and the CHP unit is turned off. The heat demand is then met by emptying the thermal store or until the spot market price increases back above the threshold value and the CHP starts again. Should the spot market price remain below the threshold value the store will completely empty itself at which point the boiler will be turned on until it is economically feasible to switch the CHP unit back on again. This can be seen throughout the entire week. When the heat demand is not being met by either the CHP or the boiler in the second graph, the thermal store in the third graph is emptying.

Operation Strategy Used for Trigeneration Plants in energyPRO

The operation strategy selected for this study is one that is preset in the energyPRO model and allows you to minimize the net cooling production cost. This is illustrated in the figure 3 ”Net cooling production cost versus electricity spot price” using two curves.

In this example, the red curve is the cost of operating the boiler, which remains constant as it can only consumes natural gas to produce heat. The yellow curve illustrates how the cost of producing cooling using a 30 MWth electric chiller unit that increases as the spot market price for electricity increases. The green curve illustrates how the cost of producing cooling with an absorption chiller unit deceases as the spot market price increases. The spot market price that corresponds to where the two chiller curves intersect is the threshold value at which it becomes economic to operate the absorption chiller unit rather than the electric chiller. The model will operate in this manner, running the absorption chilller when the spot market price exceeds approximately $42 CAD , otherwise it will utilise the cheaper electric chiller to meet the cooling demand.

Figure 3. Net cooling production cost versus electricity spot price



energyPRO Compared to Other Energy Modeling Tools

Two other deterministic modeling tools were investigated for their applicability for this analysis. Deterministic models are more applicable than probabilistic models for this application because there is only two possible outcomes which are the opposites of eachother (i.e. The investment is technically and economically feasible, or it is not). Probabilistic models are more appropriate when there is a number of different outcomes that can result from a certain action, in which case the model will utilise statistical analysis to determine the probability of each outcome.

The models investigated were energyPLAN and RETScreen. In contrast to energyPRO and RETScreen, the energyPlan model was found to be inappropriate as it is used to optimise the entire energy system rather than investments in specific plants.

The RETScreen model is used for comparing different scenarios where a reference technology is compared to an alternative one in terms of energy savings, cost savings, emission reductions and economic feasibility. However, this tool does not have the ability to model any types of thermal storage and as a result was not appropriate for this analysis. It also does not calculate results

based on an hourly timescale and therefore is not equipped for optimising production of CHP plants selling electricity into fluctuating spot markets.

Chapter 3: Ontario's Electricity Mix and Market Structure

The Electricity Mix

Ontario derives its power from a diverse mix of generation technologies which include nuclear, hydropower, coal, natural gas, wind, solar, and bioenergy. It serves over 12 million people and covers an area exceeding 1.1 million square kilometres. There is an existing installed capacity of 36975 MW. The installed capacity is divided by each respective type of generation as shown in table 1 (OPA, 2010).

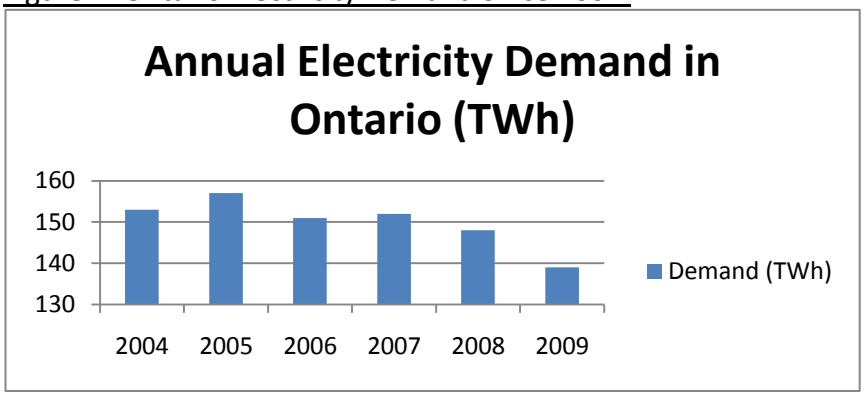
Table 1. Ontario's Electricity Supply Mix

Installed Capacity	2003	2010 (Projected)	2030 (Projected)
Nuclear	10,061	11,446	12,000
Renewables – Hydroelectric	7,880	8,127	9,000
Renewables – Wind, Solar, Bioenergy	155	1,657	10,700
Gas	4,364	9,424	9,200
Coal	7,546	4,484	0
Conservation	0	1,837	7,100
Total	30,006	36,975	48,000

(OPA, 2010).

The annual demand since 2004 has ranged from 139 to 157 TWh as indicated by figure 4.

Figure 4. Ontario Electricity Demand Since 2004.

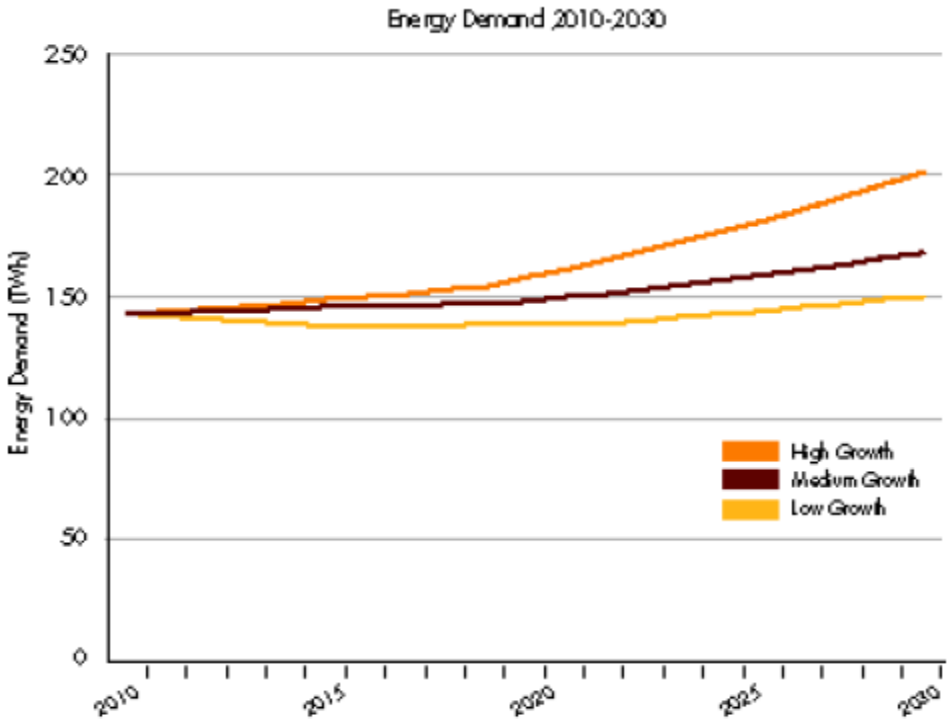


(Source Data from: Independent Electricity System Operator, 2010).

The decrease in demand since 2007 is being attributed to increased conservation and demand management programs, however, this might be misleading as the global financial crisis occurred causing a reduction in the manufacturing sector during the same period.

Future demand for electricity has been forecasted and published in the new Long Term Energy Plan. 3 scenarios have been developed for different rates of demand growth (high, moderate and low) as shown in figure 5 (OPA, 2010).

Figure 5. Projected Electricity Demand in Ontario up to 2030



(OPA, 2010)

Ontario's New Long Term Plan assumes that medium growth will be realistic up to 2030.

Ontario's Electricity Market Participants

The electrical power system in Ontario consists of power generators, transmission companies, distribution companies, and consumers. The market is a deregulated market where supply and demand dictates electricity prices. Prior to market deregulation, the market and system was historically controlled by the Ontario Hydro company who generated and sold electricity to end-use consumers through municipal utilities. Upon deregulation in order to create a competitive market Ontario Hydro was split into 3 separate companies. They consist of Ontario Power Generation Inc, Hydro One, and the Independent Electricity System Operator (Independent Electricity System Operator, 2010).

Ontario Power Generation Inc. Generates electricity and competes with other generation companies on the market (Independent Electricity System Operator, 2010).

Hydro One transmits and distributes electricity across the province (Independent Electricity System Operator, 2010).

The Independent Electricity System Operator (IESO) is in charge of the reliability of the electrical system within in Ontario. As a result they control the production and flow of electricity from generators to distribution companies and wholesale customers in order to regulate voltage levels, power flows and system equipment on any portion of the transmission grid that exceeds 50 Kilovolts. This high voltage portion of the grid system is called the "IESO-Controlled Grid" and differs from lower voltage distribution systems operated by local utility companies (Independent Electricity System Operator, 2010). The IESO does not buy or sell electricity, however, they are compensated by the wholesale and distribution companies who charge end-use consumers (Independent Electricity System Operator, 2010).

Other than the three companies that were spawned from the old Ontario Hydro Company there are also other market participants in the new deregulated market. One of the most notable is the Ontario Power Authority (OPA).

The OPA is a non-profit corporation that is responsible for forecasting future electricity demand and procuring adequate supply from generators in order to ensure security of supply. A majority of Ontario's CHP and trigeneration plants are contracted to produce predetermined levels of energy by the OPA over long-term contracts. They are also in charge of planning the future of the energy system under the directive of the Ontario Minister of Energy (OPA, 2011). This analysis aims to identify if it is profitable to allow operators of CHP plants to self-schedule their production by bidding into the spot market rather than entering into contracts with the OPA who then do the bidding for them.

Other market participants are differentiated based on whether they have physical facilities or not. For the purpose of this report only participants with physical facilities will be considered.

Ontario's Real-Time Electricity Market Structure

The markets that exist in Ontario are the wholesale market ("Hourly Spot Market") and the various operating reserve markets (Independent Electricity System Operator, 2010).

The wholesale market is a marginal price market that is utilized so that both dispatchable and non-dispatchable generators are able to sell electricity to both dispatchable and non-dispatchable loads. The price is determined for every hour of the day. The price is based on offers to supply electricity by generators and bids to buy electricity by loads. (Independent Electricity System Operator, 2010).

The operating reserve markets are utilized to provide upward and downward regulation in order to stabilize the frequency and voltage of the grid. This is done when the Independent Electricity System Operator sends out dispatch instructions that order the dispatchable generators and loads to alter their production and consumption rates until the regular dispatch can restore the system stability. The markets are classified as:

- 10 minute synchronized reserve
- 10 minute non-synchronized reserve
- 30 minute reserve

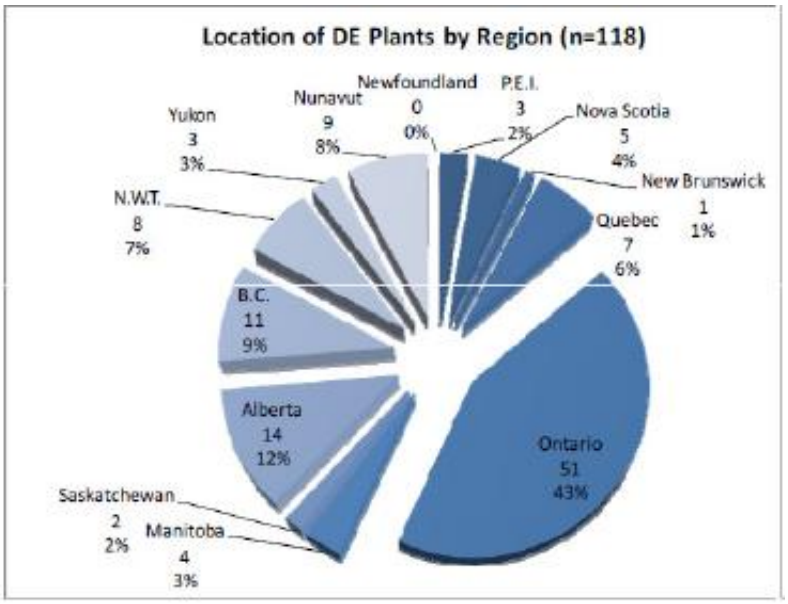
Chapter 4: CHP, Trigeneration and District Energy Systems in Ontario

District energy systems involve the production and distribution of heating and cooling for use in hydronic HVAC (heating ventilation and air conditioning) systems. In these systems the heating and or cooling is produced at a central plant that is termed an “energy centre”. Following production the thermal energy is distributed to end-use consumers via a system of sub-surface insulated pipes. Heat is provided in the form of steam or hot water, while cooling is provided as chilled water.

Once the heated or chilled H_2O reaches the destination of the end-user it is transferred to the building via energy transfer stations consisting of heat exchangers. The heat exchangers facilitate the addition or removal of thermal energy from the closed heating or cooling loop of the hydronic HVAC systems within each individual building. This energy is then circulated throughout the building’s HVAC system to provide space heating and cooling.

In Canada, the first district energy system was created in London, Ontario in 1880 to provide heat to institutional buildings (university and hospital) as well as government complexes. The University of Toronto followed in 1911 by creating a district heating system for the downtown campus (Enwave, 2011). Currently there are approximately 120 district energy systems in operation in Canada, 51 of which are located in Ontario as shown in Figure 6.

Figure 6. Location of District Energy Plants in Canada by Province



(OPA, 2010)

However, these systems are typically very small in scale when compared to those of European countries such as Denmark and Germany (OPA, 2010). District energy makes up 0.5% of energy sales in the province of Ontario. The penetration of district energy in some European countries is summarized in table 2.

Table 2. Penetration of District Energy Systems in Europe.

Country	District Heat %	CHP Share %	Connected Load (MW_{th})	Pipeline Length (km)	CHP Cap. (MW_e)
Austria	14	25	5,750	2,646	2,500
Czech Republic	22	n.a.	n.a.	2,501	3,283
Denmark	50	62	24,900	23,900	n.a.
Finland	50	36	13,820	8,340	4,200
Germany	12	8	54,126	174,970	10,675
Hungary	16	n.a.	7,600	2,062	4,521
Italy	1.5	18	3,037	996	705
Lithuania	68	n.a.	8,754	2,846	2,567
Netherlands	3	53	1,920	320	3,165
Poland	52	n.a.	n.a.	16,392	23,323
Sweden	42	6	23,298	11,180	1,928
United Kingdom	1.0	6	n.a.	n.a.	n.a.

(OPA, 2010)

Currently approximately 50% of the district energy systems in Ontario are powered by central boilers that produce heat and central chillers that produce chilled water. The other 50% of these district energy systems are powered by CHP, trigeneration systems where the production of

electricity, heat and cooling are coupled together. The current penetration of CHP in Ontario is approximately 2000 MWe installed capacity (much of which has been constructed for specific industrial applications and as a result, is not grid connected). Again this is significantly lower than some European countries such as Denmark, Poland and Germany. The Ontario Power Authority plans to install an additional 1000 MW (OPA, 2011).

The goal of this research is to increase the awareness of the technical, economic and environmental benefits that can be generated through coupling the production of electricity and heating. In the opinion of the author, the government of Ontario has not placed enough emphasis on increasing the efficiency of energy production as they are content in having 50% of electrical demand produced by large central nuclear power plants. This research aims to illustrate that the government of Ontario should focus more on distributed CHP plants and district energy systems in contrast to large central power plants and on-site production of thermal energy for space heating and cooling.

Toronto`s District Energy System

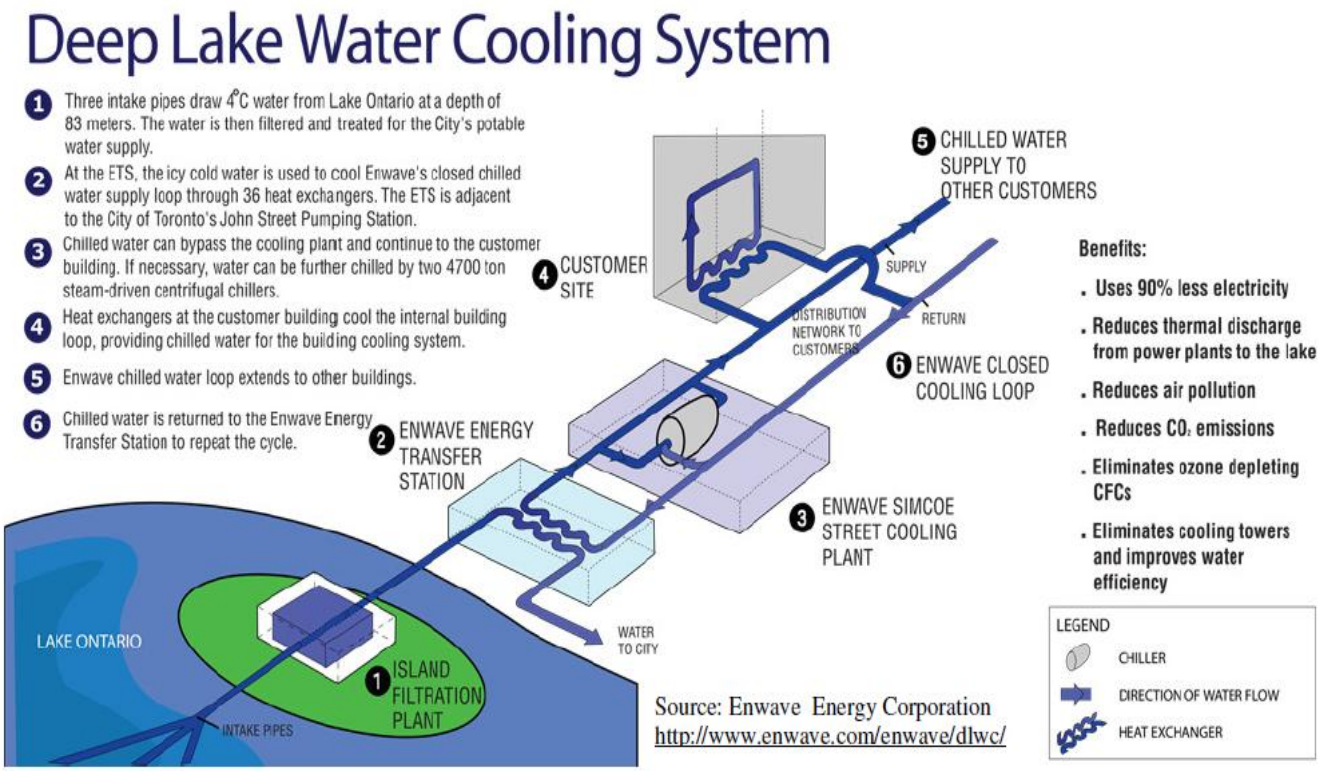
It should be noted that this section has only been included to provide background information about the existing system. Due to confidentiality issues, Enwave was unwilling to provide specific information regarding the capacity or efficiency of the existing cooling system. Enwave was also unwilling to provide annual consumption data for either the heating or cooling system.

The district energy system in Toronto is composed of both a district heating network and a district cooling network. Both of these systems service a number of residential, commercial and industrial customers located in the downtown core of the city.

The current district heating system is composed of a 3 separate steam boiler plants composed of 16 individual boilers that have an aggregate capacity of 381 MWth. The peak load of the system to date is 337 MWth. The distribution system services 140 buildings and consists of a 26 km network of subsurface piping (Enwave, 2010).

The current district cooling system is composed of two different kinds of cooling plants. The first plant is called a deep lake cooling plant where water from deep within Lake Ontario is pumped to the surface and utilised in a heat exchanger plant in order to remove heat from the chilled water in the closed cooling loop of the system. This chilled water is then distributed to customers or it can be sent to a steam-driven centrifugal chiller plant to further reduce the temperature during periods of peak demand when outdoor ambient temperature rises above a certain threshold level. The distribution system for cooling services 29 builidings. Figure 7 illustrates how the district cooling system operates (Enwave, 2010).

Figure 7. Description of Deep Lake Water Cooling System in Toronto, Ontario, Canada



(Enwave, 2010)

Chapter 5: Energy Conversion Units

This section is intended to provide a brief overview of the technologies being utilised to produce thermal and electrical energy in the scenario's being analysed. The technologies to be summarized are district heating gas boilers, gas engines, electric chillers and absorption chillers.

District Heating Gas Boiler

In a natural gas boiler fuel is burned in the furnace section and the heat is used to boil water in the boiler section which is then distributed to end consumers. Table 3 summarizes the technical characteristics, environmental emissions and costs of gas boilers.

Table 3. Overview of District Heating Gas Boiler Technology

Technology	District heating boiler, gas fired					
	2010	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one plant (MJ/s)	0.5 - 10	0.5 - 10	0.5 - 10			2
Total efficiency (%) net	97 - 105	97 - 105	97 - 105		A	2
Availability (%)	95 - 97	95 - 97	95 - 97			1
Technical lifetime (years)	20	20	20			1
Construction time (years)	0.5 - 1	0.5 - 1	0.5 - 1			1
Environment (Fuel: natural gas)						
SO_2 (degree of desulphuring, %)	0	0	0	0		3
NO_X (g per GJ fuel)	42	42	42	42		4;3;3;3
CH4 (g per GJ fuel)	6	6	6	6		4;3;3;3
N2O (g per GJ fuel)	1	1	1	1		4;3;3;3
Financial data						
Specific investment (M€ per MJ/s)	0.06-0.12	0.06-0.12	0.06-0.12		B+C	2
Total O&M (% of initial investment per year)	2 - 5	2 - 5	2 - 5			1

(Energinet.dk, 2010)

CHP Gas Engine

Gas engines utilise the combustion of natural gas to drive an electrical generator. Waste heat can be used in CHP systems in order to provide heat for district heating or other demands such as industrial processes. Table 4 summarizes the technical characteristics, environmental emissions and costs of gas engines.

Table 4. Overview of Natural Gas Engine Technology

Technology	Spark ignition engine, natural gas					
	2010	2020	2030	2050	Note	Ref
Energy/technical data						
Generating capacity for one unit (MW)	1 - 10					
Total efficiency (%) net	88 - 96	88 - 96	88 - 96		A	4
Electricity efficiency (%) net	40 - 45	43 - 48	45 - 50			5
Cb (50°C/100°C)	0.9					
Availability (%)	95	95	95		B	1+3
Technical lifetime (years)	20 - 25	20 - 25	20 - 25		C	1+3
Construction time (years)	< 1	< 1	< 1			1
Environment						
SO_2 (degree of desulphuring, %)	0	0	0	0		6
NO_X (g per GJ fuel)	135	60	60	60	D	5:8;8;8
CH4 (g per GJ fuel)	465	420	375	250	G	5
N2O (g per GJ fuel)	0.6	0.6	0.6	0.6		5
Financial data						
Specific investment (M€/MW)	0.9 - 1.4	0.9 - 1.4	0.9 - 1.4		E	1
Total O&M (€/MWh)	7-11	7-11	7-11		E	5
Regulation ability						
Fast reserve (MW per 15 minutes)	From cold to full load within 15 minutes					1
Minimum load (% of full load)	50				F	1

(Energinet.dk, 2010)

Electric Chiller

Electric chillers utilise electricity to drive a vapour-compression refrigeration cycle using various types of refrigerants as the heat exchange medium. Chilled water is produced and then pumped to coils or heat exchangers where it is used to chill and dehumidify air within buildings. Figure 8 Illustrates the range of efficiencies and COP that can be expected. For the purpose of this report we will be choosing a chiller with a "good" rating representing a conventional chiller plant (ASHRAE, 2001).

Figure 8. Electrical Chiller Efficiency Ratings (Annual Average)

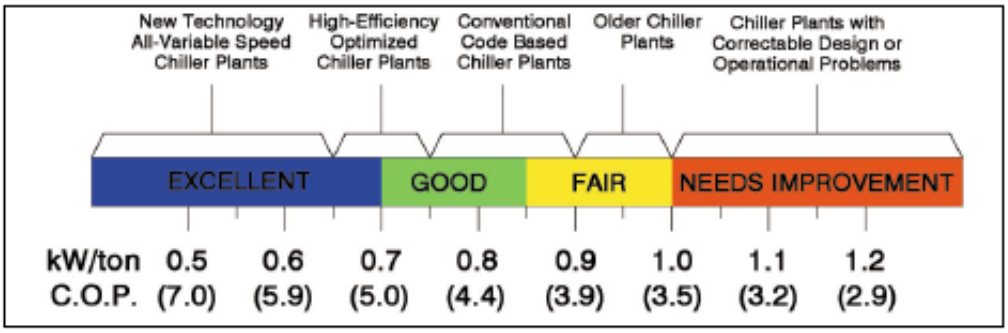


Figure 5: Average annual chiller plant efficiency in kW/ton (COP). Input energy includes chillers, condenser pumps and tower fans, based on electrically driven centrifugal chiller plants in comfort conditioning applications with 42°F (5.6°C) nominal chilled water supply temperature and open cooling towers sized for 85°F (29.4°C) maximum entering condenser water temperature. Local climate adjustment for North America climates is ±0.05 kW/ton.

(ASHRAE, 2001)

The emissions associated with electrically driven chillers are a product of the mix of generation technologies and fuels used to generate electricity in Ontario. Table 5 illustrates the emissions produced during the generation of each MWh of electricity.

Table 5. Emissions Intensity of Electricity Generated in Ontario

Ontario	Emissions Intensity (tonnes/MWh electricity generated) **2010**
CO_2 Intensity	0,179
SO2 Intensity	0,00049
NO Intensity	0,00025
Overall Intensity3	
(tonnes CO_2 eq/MWh)	0,179

(Bullfrog Power, 2010)

Absorption Chiller

Absorption chillers produce cooling via the utilisation of heat. The process utilises either ammonia or water mixed with salt as a refrigerant. The most commonly used salt is lithium bromide (LiBr). Absorption chillers are available in 3 different designs:

- Single-effect indirect-fired
- Double-effect indirect-fired
- Double-effect direct-fired

For the purpose of this study we will focus on single-effect indirect-fired absorption chillers as they are best accommodated to utilising the low temperature waste heat produced by a CHP engine when compared to a double-effect indirect-fired absorption chiller (Energy Solutions Center, ND). Double-effect direct-fired absorption chillers are being disregarded as they also consume gas to preheat the incoming hot water or steam used to run the refrigeration cycle. For more information on double-effect (indirect and direct-fired) chillers see APPENDIX 2.

Single-effect indirect-fired chillers consist of a single generator and condense the gaseous (vaporized) refrigerant in a single condenser. They are considered indirect-fired as they require an external heat source (e.g. process heat or low temperature waste heat from CHP units) to power the phase change of the refrigerant in order to produce cooling.

The refrigerant loop is in a state of partial vacuum in order to enable the refrigerant to vaporize at a low saturation temperature (boiling point). As a result, the internal pressure of absorption chillers can range from 0.1 to 0.01 atmosphere (atm). (Miller and Miller, 2006) and (Sakraida, 2009)

Absorption Chiller Refrigeration Cycle and Components

A single-effect indirect-fire absorption chilling system is composed of five components; a generator, a condenser, expansion piping, an evaporator, and an absorber. All of the components are illustrated in figure 9. The refrigeration cycle and the function of each component is summarized below:

- Generator: The generator heats up the H2O/LiBr refrigerant and causes the H20 to vaporize. The vaporized H20 then travels to the condenser, while the LiBr solution travels to the absorber.

- Condenser: The gaseous H2O vapour is reduced in temperature by cooling water circulating in a closed loop of coils within the condenser. This causes the H20 to condense back to a liquid state, transferring heat to the cooling water, thus lowering the temperature of the H2O.

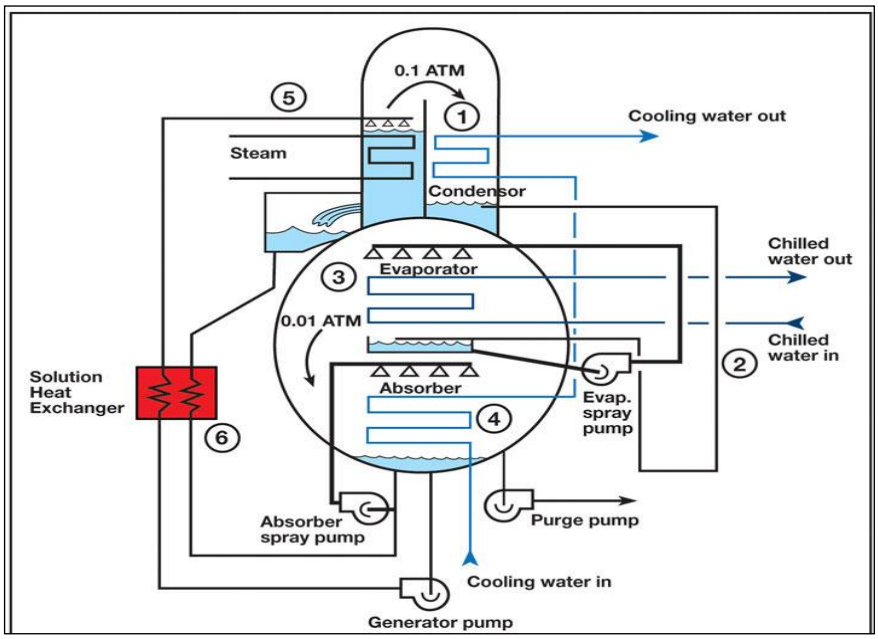
- Expansion Piping: The liquid refrigerant travels through expansion piping en route to the evaporator. As it travels it experiences a drop in pressure and thus a drop in temperature.

- Evaporator: The liquid refrigerant is then sprayed on the chilled water loop coils in order to utilise maximum surface area for evaporation. Due to the drop in pressure that occurred in the expansion piping, the H2O is able to evaporate again creating water vapour. The heat energy existing in the water of the chilled loop is then transferred to the vapour, decreasing the chilled water temperature to a point (4°C) where it can be used to

cool the air within a closed space (i.e. refrigerator, building etc). The refrigerant then travels to the absorber.

- Absorber: The gaseous refrigerant is sprayed with LiBr solution in the absorber, causing the two to recombine into a liquid solution. The LiBr refrigerant solution can then travel in two paths. One path is back to the generator to be heated to start the cycle again, while some of the solution travels back to the absorber spray nozzles. (Miller and Miller, 2006) and (Sakraida, 2009)

Figure 9. Components and Process of Absorption Chiller

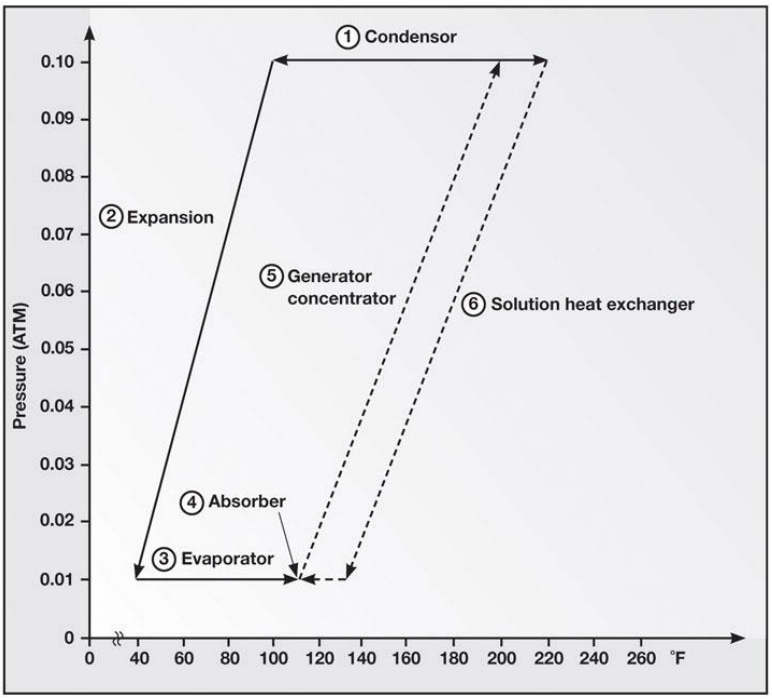


(Sakraida, 2009)

It should be noted that there are controls and pumps driving the refrigerant that require electricity to operate, however for the purpose of this report this energy consumption has been neglected.

As was stated earlier, the refrigerant undergoes changes in pressure within the closed loop. Figure 10 Illustrates the differing pressures that occur during the cycle in each of the components.

Figure 10. Changes in Pressure within Absorption Chiller Loop



(Sakraida, 2009)

Absorption Chiller Efficiency

Chiller efficiency is measured as cooling production per unit of fuel consumed. As such it can be measured in BTUh, or kWh of cooling. Chiller capacity can be stated in tons, BTU or kW.

The term used to indicate the efficiency of a chiller is coefficient of performance (COP). The equation for COP is Energy output (i.e. chiller capacity) divided by Energy input (i.e. heat input), where:

- Energy Output (BTUh or kWh of cooling produced) / Energy Input (BTUh or kWh of heat for absorption)

  (e.g. 3.516 kW capacity chiller with a COP = 0.7 operating for 1 hour would require approximately 5.023 kWh).

Single-effect indirect-fired absorption chillers have a coefficient of performance (COP) typically ranging from 0.6 – 0.75 (Sakraida, 2009).

For information on COP for double-effect absorption chillers please see APPENDIX 2.

It should also be noted that there a number of factors that affect the capacity and efficiency of absorption chillers such as incoming hot water temperature. For a full discussion on the factors please see APPENDIX 2.

Chapter 6: Scenario Building

In order to determine whether operating a CHP plant is technically and economically feasible under Ontario market conditions and whether an optimised CHP plant can be converted into a trigeneration system using absorption chillers, a number of different scenarios will be compared using the energyPRO modeling software tool. As a result, two separate Analyses will be constructed, one where only district heating demand is considered and a second where both district heating demand and district cooling demand are considered.

Analysis #1: District Heating Demand Only

2 reference scenarios have been constructed that consist of the same annual heat demand supplied by natural gas-fired boiler plants such as the one that currently exists in Toronto. The first reference scenario assumes a boiler efficiency of 95% which is similar to newer systems with heat recovery, while the second assumes a boiler efficiency of 90%. For the purpose of this study it is assumed that the existing system operates on hot water instead of steam due to the lack of specific information regarding the Toronto system. The thermal capacity of the boiler plants was selected to be 38 MWth as there is a maximum heat demand of 34 MW for the hypothetical system. By selecting a boiler capacity that exceeds the peak heat demand it ensures that the boiler is able to supply all heat required at any time throughout the duration of the year being analysed.

Alternative 1 includes the same annual and peak demands for heat as the reference scenarios, however, in addition to the 38 MWth boiler plant, this scenario incorporates a CHP gas engine with a thermal storage tank. The CHP will produce electricity for sale on the wholesale market when it is economic to do so and the associated heat produced will be supplied to the district heating network to supply the concurrent heat demand or it will be stored in the thermal storage for use at a later time. During times when the wholesale market price for electricity is below the marginal cost of running the CHP, the heat demand will be met by the existing natural gas boiler plant.

The alternative scenario will be compared to both references in order to determine whether it is feasible to convert both old and new systems; only old systems; or neither system due to insufficient economic viability.

In the event that it is not economically feasible to convert either reference system to CHP, the analysis will include 2 other alternative scenarios where the spot price for electricity is increased incrementally in attempt to identify the required percentage increase in hourly spot market prices that is required to make the conversion to CHP economically feasible. These scenarios will be called alternative scenario 2 (25% increase in Spot price) and alternative scenario 3 (50% increase in spot price).

Analysis #2: District Heating and Cooling Demand

For this analysis the optimal sized plant identified in Analysis #1 will be used to create reference scenario 3, where a cooling demand and an electric chiller is added. The electric chiller has a

capacity of 50 MWth to ensure that it can cover peak cooling demands throughout the year being analysed.

Alternative scenario 4 will include absorption chillers varying in capacity to identify whether or not it is techno-economically feasible to convert an optimised (existing) CHP plant with electric chillers to a trigeneration system using absorption chillers without altering the original system.

Net Present Value Calculations

In order to calculate the net present value for Analysis #1, the cost of supplying the annual heat demand in the reference scenario was compared with the cost of supplying the heat demand with the CHP units in order to determine the economic feasibility of switching to a CHP plant with thermal storage. The difference in cost between the reference and alternative scenarios was seen as annual cash flow. The net present value of various combinations of CHP capacities and thermal storage capacities are calculated in order to determine the optimal plant size for each of the alternative scenarios.

In order to calculate the net present value for Analysis #2, the cost of supplying heat and cooling using boilers, CHP and electric chillers is compared to the cost of supplying heat and cooling using boilers, CHP, electric chillers and absorption chillers. The difference in cost between the reference and alternative scenarios was seen as annual cash flow. The net present value of various combinations of absorption chiller capacities is calculated to see if it is economically feasible to convert an optimised CHP plant with electric chillers to a trigeneration system.

The period utilised in the calculations was 15 years. A real discount rate of 3.5% was utilised. Currently, the inflation rate in the Canada is approximately 3.3% and is estimated to remain at that rate producing a nominal discount rate of 6.8%. The discount rate is used to discount future cash flows to their present value and is a variable that has a very large influence on the net present value (Bank of Canada, 2011).

In investment theory a net present value greater than zero indicates a profitable investment. As a result the optimal size of a CHP plant with thermal storage will have the greatest net present value exceeding zero. If none of the CHP plant thermal storage combinations render a positive net present value than it would be seen as better from a economic point of view not to retrofit the existing boiler-only plant from the reference scenario.

Sensitivity Analysis

Sensitivity analysis was performed on the discount rate, fuel price and wholesale electricity prices in order to determine how fluctuations in those variables impact the net present value for both alternative scenarios.

Sensitivity analysis was conducted in order to determine the impact of various discount rates on the profitability of the optimal size plant for the first alternative scenario. Sensitivity analysis was also performed to investigate how the optimal size of a plant varies when different discount rates are applied in the calculation of net present value.

Sensitivity analysis was conducted for both fuel and electricity market prices to see how variations of ± 10% would impact the net present value of the optimal size plant for each of the alternative scenarios.

System Demands

The following table illustrates the system capacity, efficiency, demand and consumption for heating and cooling that have been used for these analyses. For the purpose of these analyses the system values have been scaled down by a factor of 10. As the company Enwave would not formally disclose this information the author has based this information on personal communications with Enwave engineers, however, it should be stated that this is not actual data, and is therefore completely hypothetical in nature. The reference models for both Analysis #1 and Analysis #2 are defined in table 6.

Table 6. Reference Model Capacities, Efficiencies, Demands and Consumptions

REFERENCE MODEL (Analysis #1 and #2)		
Heating System		Decreased by factor of 10
Capacity (MW)	380	38
Efficiency (Boiler)	95%	95%/90%
Peak Demand (MW)	360	36
Annual Consumption (MWh)	585995	58599
REFERENCE MODEL (Analysis #2)		
Cooling System		Decreased by factor of 10
Capacity (MW)	50	50
Efficiency (Electric Chiller)	75%	75%
Peak Demand (MW)	375(Assumed)	37.5
Annual Consumption (MWh)	200000	20000

Peak Cooling Demands are assumed to be this high based on the modeled distribution of the annual cooling demands based on cooling degree days calculated from outdoor ambient temperatures.

Fuel and Electricity Prices

Natural gas which is the fuel being utilised to power both the boiler and CHP engines is valued at $0.36/m3 as was the average in 2010 for Union Gas (OPA, 2011).

Hourly spot market prices for electricity have been downloaded from the IESO website. This analysis uses data that spans the calendar year of 2010. This data is used to calculate revenues from electricity sales and also costs of electricity consumption for the CHP engine and the electric chiller respectively.

Technical and Economic Characteristics of Conversion Units

The following is a summary of the technical characteristics and costs that have utilised in the analyses completed.

District Heating Gas Boiler

As was stated the capacity of the boiler systems is 38 MWth and the costs are assumed to be negligible as the system is assumed to already exist. The efficiencies analysed are 90% and 95%.

CHP Gas Engine

The gas engine is assumed to have a combined efficiency of 95% which is the upper limit as indicated by Energinet.dk. The thermal efficiency is 51% while the electrical efficiency is 45%. Table 7 illustrates the separate thermal and electrical efficiencies of CHP engines with different Capacities (MWe) and the associated fuel consumption.

Table 7. CHP Gas Engine Thermal and Electrical Efficiencies.

CHP Efficiency (95%)		
FUEL (MW)	MWth (51%)	Mwe (45%)
2,2	1,1	1
4,4	2,2	2
6,6	3,3	3
8,8	4,4	4
11	5,5	5
13,2	6,6	6
15,4	7,7	7
17,6	8,8	8
19,8	9,9	9
22	11	10
24,2	12,1	11
33	16,5	15
44	22	20

The costs for the CHP gas engine are summarized in Table 8.

Table 8. CHP Cost Assumptions

Fuel Costs for the Canada (2009)	$CAD	
Cost per M3	0,36	Source: Union Gas 2010, (OPA, 2011)
CHP Costs	$CAD	
Initial Investment ($CAD/MW)	1.223.083	Source: Energinet.dk, 2010
O&M ($CAD/MWh)	6,00	Source: OPA, 2011
Start-Up Cost for CHP (£$CADStart)	6,84	Source: EMD Internation A/S
Thermal Storage Investment ($CAD/m3)	170	Source: EMD Internation A/S

Electric Chiller

As was stated earlier the electric chiller has a capacity of 50MWth and operates at an efficiency of 75%. The price paid for electricity is that of the Hourly Ontario Spot Market price.

Absorption Chiller

Table 9 summarizes the investment cost assumptions made for the absorption chiller. This table of investment costs was provided by Trane USA on their website. Conversion from imperial to metric units was completed by the author.

Table 9. Absorption Chiller Investment Costs

Trane Costs (Initial Investment) $CAD	Capacity	Unit Cost ($)
1 Stage absorption chiller	90 - 1600 Tons	$350.00
	316.44 - 5626.6 kW	100,00
Installation, Setting, Rigging	per ton	$60.00
	per kW	$17.00
Pumps	per Horse Power (HP)	$250.00
	per kW	$335.00
Controls	per ton	$45.00
	per kW	$13.00
Electrical	per kW	$245.00
Plate and Frame Heat Exchanger	per ton	$45.00
	per kW	$13.00
Total per MW Capacity ($CAD)	723000	

(Trane USA, 2010)

Through personal communication with Trane sales manager operation and maintenance costs not including emergency repairs or parts warrantees can be estimated at approximately $7000 per annum and was included in the net present value calculations rather than in the model (Sienkiewicz,2010).

Chapter 7: Results of Analyses

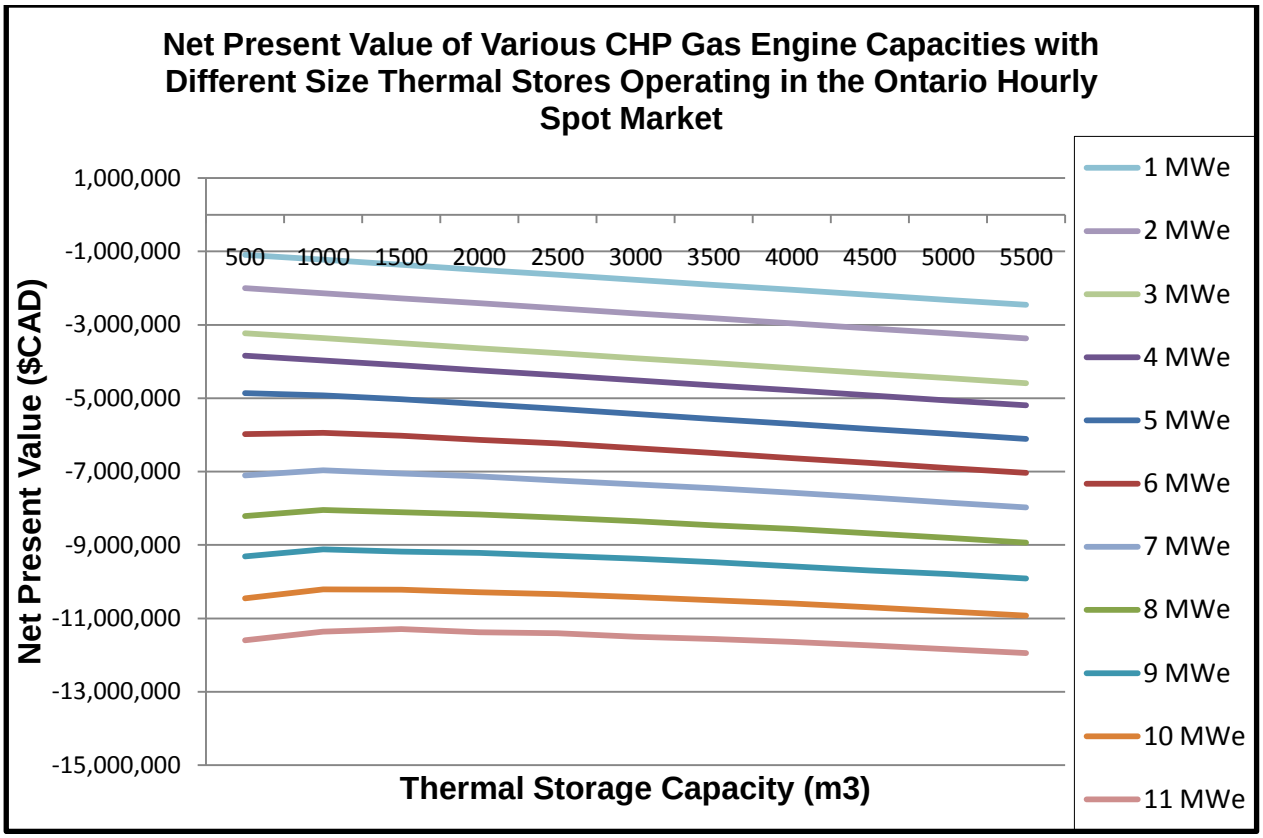
The following chapter summarizes the results of the analyses completed. All of the raw data for the figures can be found in APPENDIX 1.

Analysis #1(Reference Scenario 1 and Alternative Scenario 1)

Analysis #1 consisted of comparing the boiler only reference scenarios with a CHP gas engine alternative scenario. Figure 11 Summarizes the results for reference scenario 1 which consists of a 95% efficiency boiler plant when compared to alternative scenario 1 that includes a 95% efficient CHP plant.

Utilising the energyPRO modeling software package it was determined that there is no optimal size capacity of a CHP gas engine and thermal storage operating in the Ontario hourly spot market when a real discount rate of 3.5% is applied in the net present value calculations. This is due to the fact that spot market prices are not sufficiently high enough to have revenue from electricity sales outweigh the investment costs of the CHP engines with thermal storage tanks. This is illustrated in figure 11.

Figure 11. NPV of CHP plants and Thermal Stores



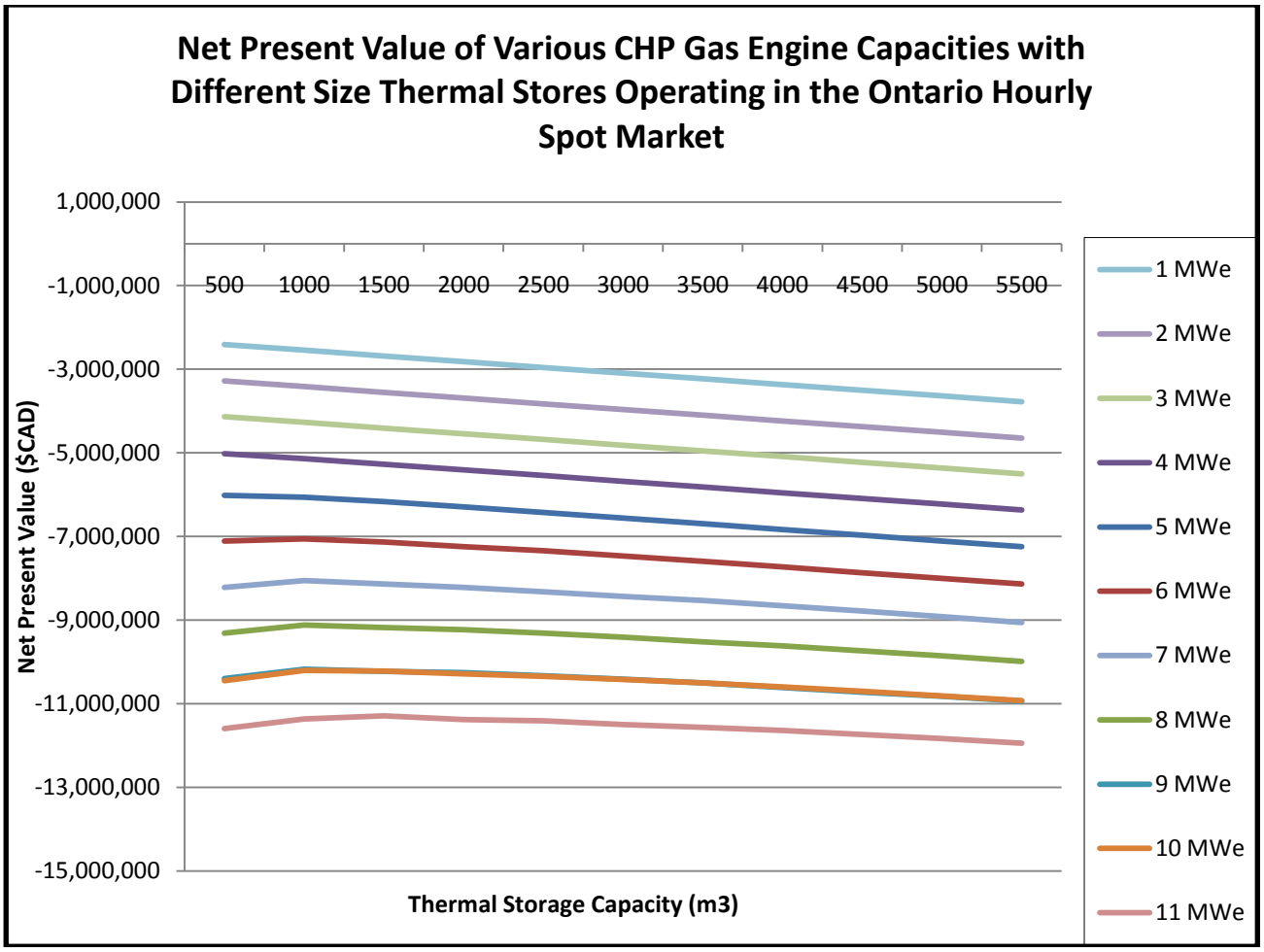
It is evident that the CHP engines are not being allowed to operate and the thermal storages are not being utilised as the graph illustrates declining NPV values as the amount of investment increases. This indicates that the spot market price for electricity is much to low in Ontario for CHP to be economically feasible in comparison to a boiler plant that operates at an efficiency of 95%. The threshold value at which the spot market price exceeds the marginal costs of operating the CHP is approximately $42 CAD. During the year of 2010 the spot market price for electricity was below this value during 7131 hours of the year or approximately 82% of the time.

Analysis #1(Reference Scenario 2 and Alternative Scenario 1)

Analysis #1 consisted of comparing the boiler only reference scenarios with a CHP gas engine alternative scenario. Figure 11 Summarizes the results for reference scenario 2 which consists of a 90% efficiency boiler plant when compared to alternative scenario 1 that includes a 95% efficient CHP plant.

Utilising the energyPRO modeling software package it was determined that there is no optimal size capacity of a CHP gas engine and thermal storage operating in the Ontario hourly spot market when a real discount rate of 3.5% is applied in the net present value calculations. This is due to the fact that spot market prices are not sufficiently high enough to have revenue from electricity sales outweigh the investment costs of the CHP engines with thermal storage tanks..

Figure 11. NPV of CHP plants and Thermal Stores for Alternative 1



It is evident that the CHP engines are not being allowed to operate and the thermal storages are not being utilised as the graph illustrates declining NPV values as the amount of investment increases. This indicates that the spot market price for electricity is much to low in Ontario for CHP to be economically feasible in comparison to a boiler plant that operates at an efficiency of 95%. The threshold value at which the spot market price exceeds the marginal costs of operating the

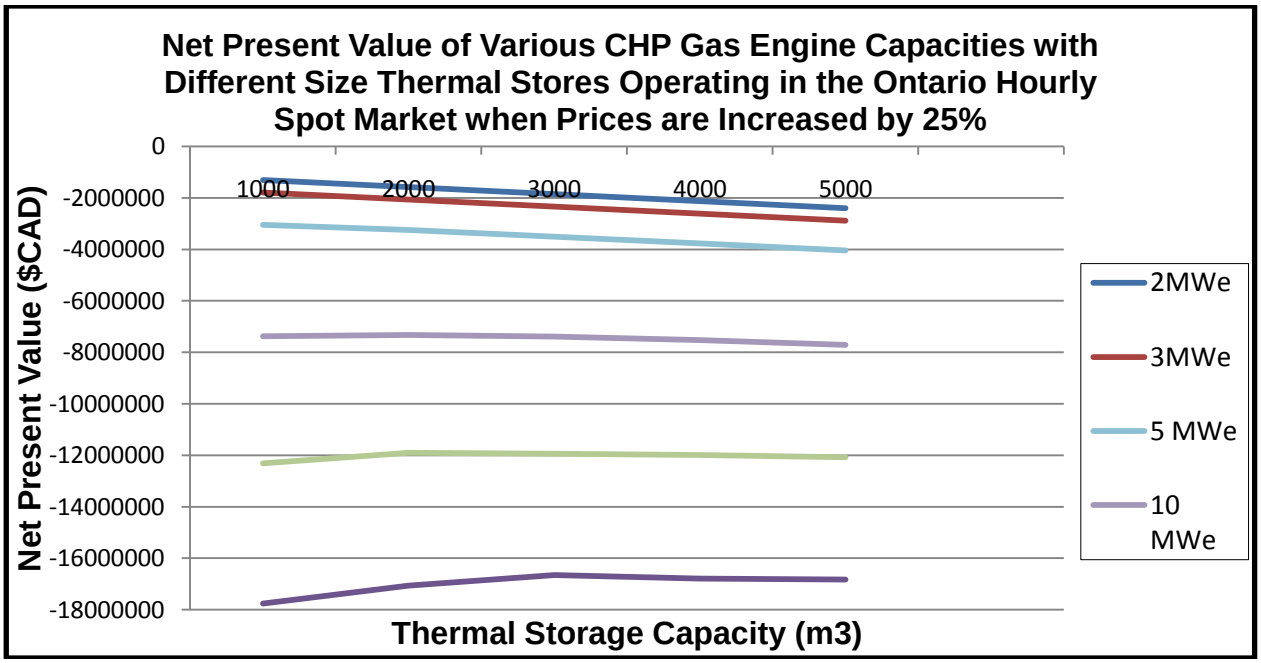
CHP is approximately $39 CAD. During the year of 2010 the spot market price for electricity was below this value during 6448 hours of the year or approximately 74% of the time.

Analysis #1(Reference Scenario 1 and Alternative Scenario 2)

Analysis #1 consisted of comparing to boiler only reference scenarios with a CHP gas engine system. Figure 12 Summarizes the results for reference scenario 1 which consists of a 95% efficiency boiler plant when compared to the alternative scenario 2 that includes a 95% efficient CHP plant and a 25% increase in the Ontario Hourly Spot Market Price for electricity.

Utilising the energyPRO modeling software package it was determined that there is no optimal size capacity of a CHP gas engine and thermal storage operating in the Ontario hourly spot market when a real discount rate of 3.5% is applied in the net present value calculations. This is due to the fact that spot market prices are not sufficiently high enough to have revenue from electricity sales outweigh the investment costs of the CHP engines with thermal storage tanks even after the spot market prices have been increased by 25% in all hours of the year.

Figure 12. NPV of CHP plants and Thermal Stores For Alternative 2



It is again, evident that the CHP engines are not being allowed to operate and the thermal storages are not being utilised as the graph illustrates declining NPV values as the amount of investment increases. For the 5 and 10 MW CHP engines, you can see a slight increase in the slope of the NPV curve moving from 1000 m3 thermal storage to 2000 m3 thermal storage, however this is not very significant as the NPV is still below zero.

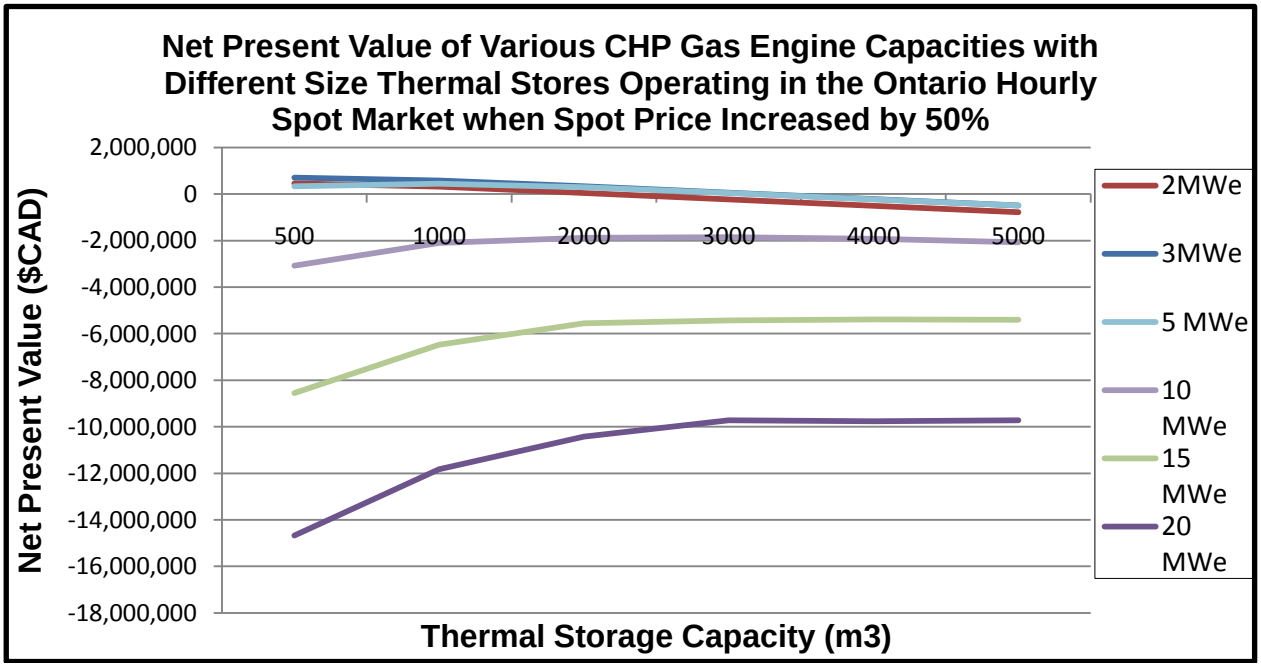
Again, this indicates that the spot market price for electricity is much to low in Ontario for CHP to be economically feasible in comparison to a boiler plant that operates at an efficiency of 95%. The threshold value at which the spot market price exceeds the marginal costs of operating the CHP is

approximately $39 CAD. During the year of 2010 the spot market price for electricity was below this value during 6448 hours of the year or approximately 74% of the time.

Analysis #1(Reference Scenario 1 and Alternative Scenario 3)

Analysis #1 consisted of comparing to boiler only reference scenarios with a CHP gas engine system. Figure 13 Summarizes the results for reference scenario 1 which consists of a 95% efficiency boiler plant when compared to the alternative scenario 3 that includes a 95% efficient CHP plant and a 50% increase in the Ontario Hourly Spot Market Price for electricity
.
Utilising the energyPRO modeling software package it was determined that the optimal size capacity of a CHP gas engine and thermal storage operating in the wholesale market is 3 MWe and 500 m3 respectively when a real discount rate of 3.5% is applied in the net present value calculations. This combination of capacity sizes yields a net present value of $CAD 543.559 a simple payback time of 10.08 years and an internal rate of return equal to 5%.

Figure 13. NPV of CHP plants and Thermal Stores for Alternative 3



Upon reviewing the results it is apparent that the thermal storage size has relatively no impact on the net present value of the smaller capacity CHP engines. This is because they are not producing excess heat due to the fact that heat demand exceeds their production. As a result, the NPV decreases as the thermal storages size is increased due to the additional investment costs and the lack of reducing fuel consumption due to underutilisation. The larger CHP engines do illustrate that increasing the thermal storage capacity does increase the NPV up to a certain point, after which it levels off and remains negative due to the large capital costs associated with the increased capacity of the engine. This increase in net present value continues until the additional

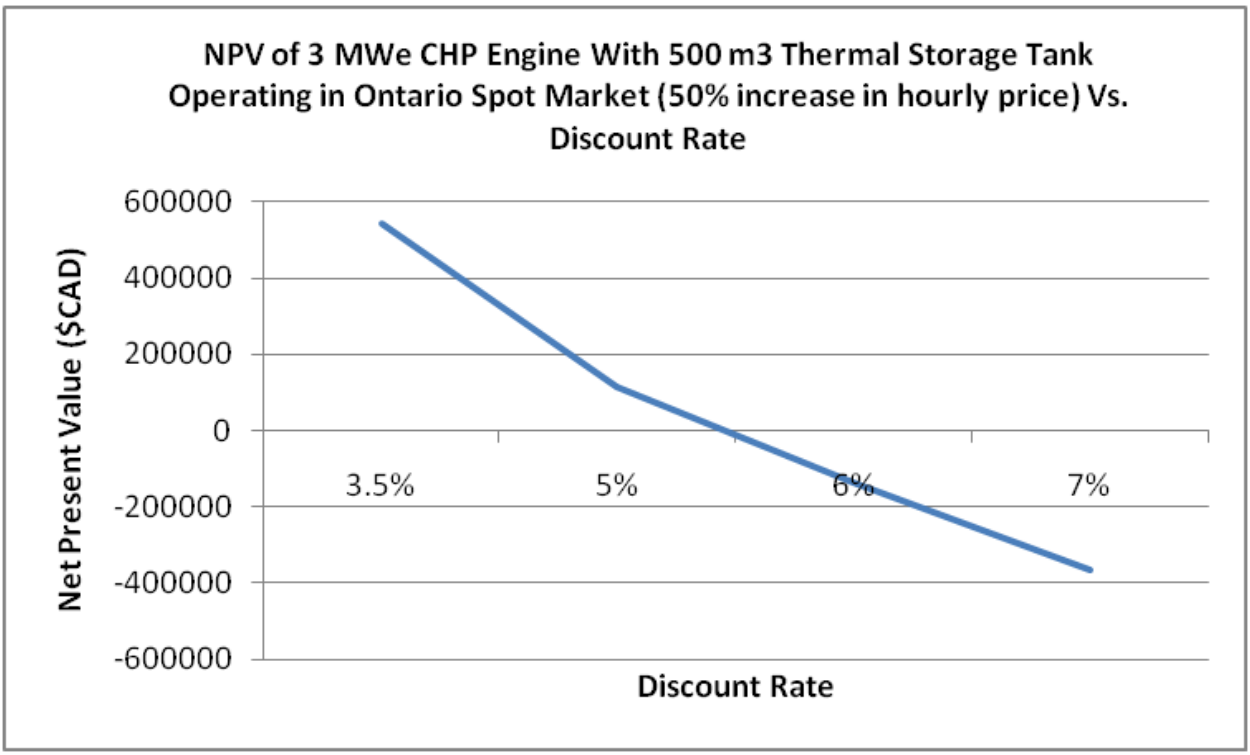
revenue gained through electricity sales is overcome with the investment costs of additional thermal storage capacity at which time it becomes relatively constant and would eventually decrease.

This indicates that finding an optimal sized CHP engine is more important than finding an optimal combination of CHP and thermal storage tank under current market conditions in Ontario due to low electricity sales and resulting revenues.

Discount Rate Sensitivity Analysis of a 3 MWe CHP Engine with a 500 m3 Thermal Storage Operating in the Ontario Hourly Spot Market When Spot Price is increased by 50%

It can be seen in figure 14 and that the discount rate has a large impact on the net present value of the investment. A 3 MWe CHP engine with a 500 m3 thermal storage has a positive net present value until a discount rate of approximately 5.5%. As a result, depending on the discount rate applied in the net present value calculations this investment could be seen as either profitable or not profitable.

Figure 14. Discount Rate Sensitivity Analysis of NPV of Optimal CHP Plant for Alternative 3



Discount Rate Sensitivity Analysis of the Optimal Size of a CHP and Thermal Storage For Alternative Scenario 3 when Ontario Hourly Spot Market When Spot Price is increased by 50%

In table 10 it can be seen that the optimal size capacity of the CHP varies depending on the discount rate applied in the net present value calculations. It is also apparent that the capacity of the thermal storage remains constant illustrating that it plays little to no role in increasing the NPV. As a result the discount rate applied is very important when trying to design the optimal size engine. As the discount rate increases, the optimal size capacity of CHP engine decreases.

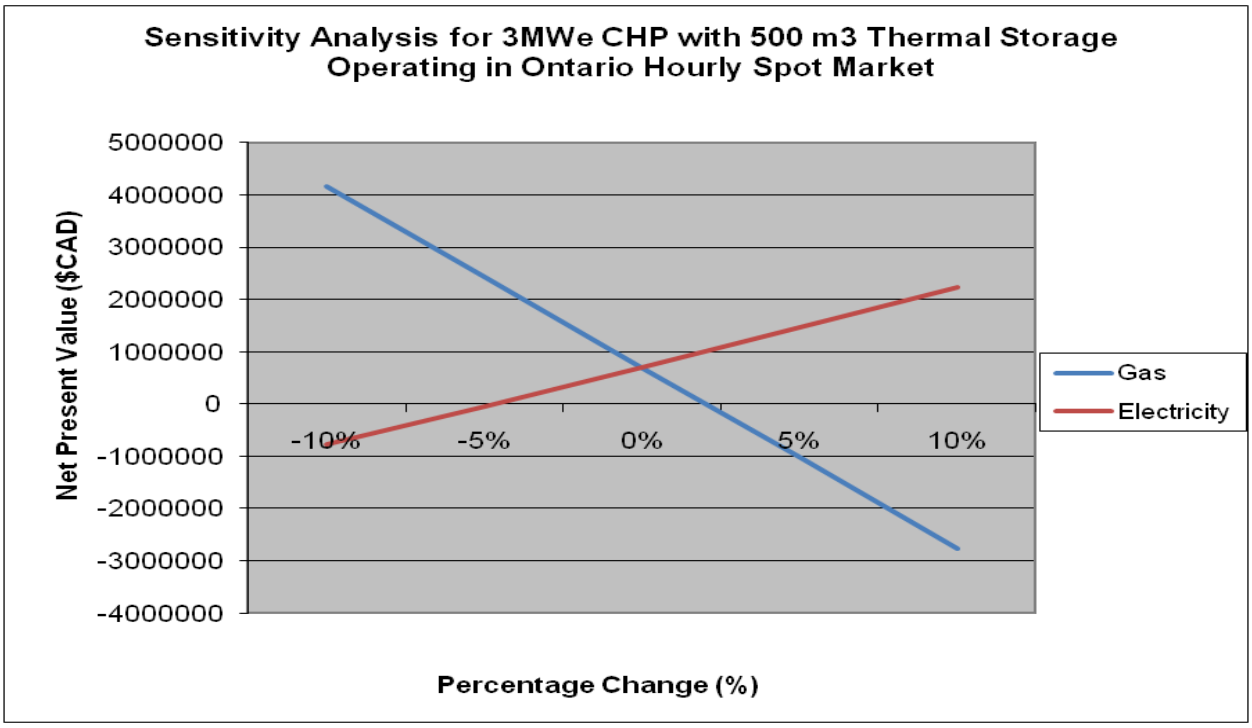
Table 10. Impact of Discount Rate on Optimal Size Plant for Alternative 3

Discount Rate	CHP Capacity	Thermal Storage Capacity	Net Present Value
3.5	3MWe	500	702.361
5	3MWe	500	113.911
6	2MWe	500	-113.647
6	2MWe	500	-267.279

Fuel and Electricity Price Sensitivity Analysis for Alternative Scenario 3

Wholesale market electricity prices and natural gas prices are varied ± 10% in order to determine the impact of price variations on the net present value of the optimal sized CHP engine and thermal storage for each alternative scenario. The impacts are illustrated in the figure 15

Figure 15. Sensitivity Analysis to Fluctuating Natural Gas and Electricity Prices for Alternative 3



Changes in the wholesale market electricity price have the least influence on the net present value of the investment. When the price was varied by 5% and 10% the percentage change in net present value was equal to 108% and 218% respectively. When the price was decreased by 5% and 10% the percentage change in net present value was equal to -106% and -211% respectively.

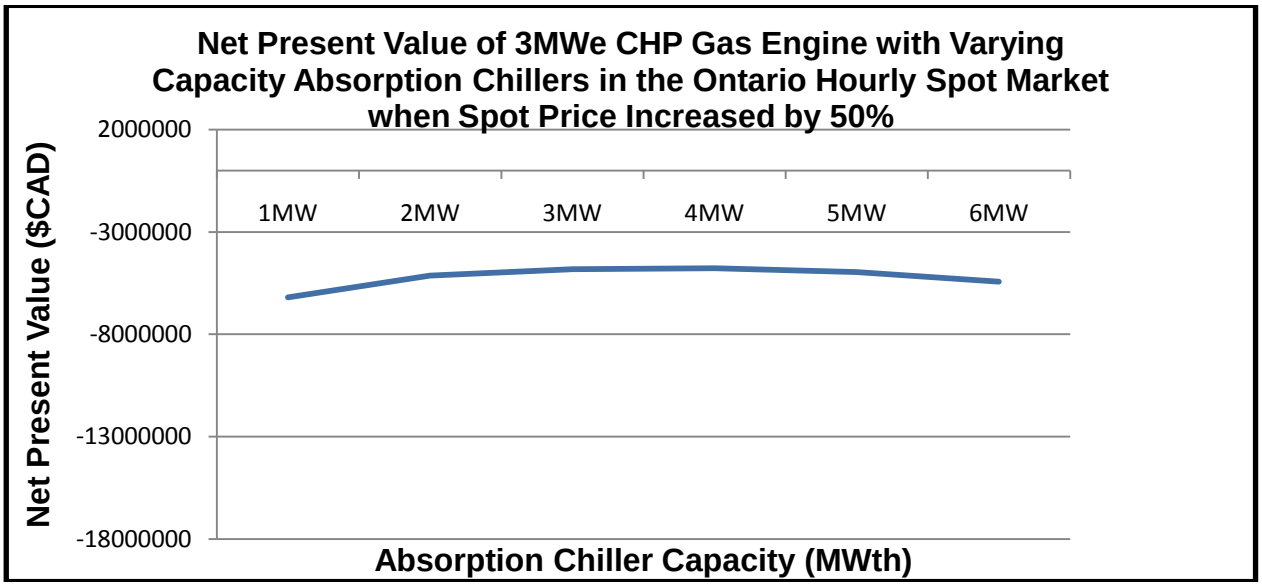
In contrast to the electricity price, fluctuations of natural gas prices have the largest influence on net present value. The relationship between natural gas price and net present value is inverse. As a result, when the gas price is increased by 5% and 10%, the percentage change in net present value is equal to -245% and -494% respectively. When the Gas price is decreased by 5% and 10% the percentage change in net present value is equal to 247% and 494% respectively.

Analysis #2(Reference 3 (Optimised CHP from Analysis #1, Alternative 3 with added cooling demand and electric chiller) and Alternative Scenario 4)

Analysis #2 consisted of comparing the optimal CHP plant from Analysis #1, Alternative 3 with a cooling demand and electrical chillers to alternative scenario 4 where absorption chillers are added. Figure 16 Summarizes the results for reference scenario 3 which consists of a 75% efficiency electric chiller when compared to the alternative scenario 4 that includes a 70% efficient absorption chiller and a 50% increase in the Ontario Hourly Spot Market Price for electricity.

Utilizing the energyPRO modeling software package it was determined that there is no optimal size capacity of an absorption chiller operating in the Ontario hourly spot market when a real discount rate of 3.5% is applied in the net present value calculations. This is due to the fact that spot market prices are sufficiently low enough to make the electric chiller more competitive due to its higher efficiency and the lack excess heat produced by the CHP engines. Also the initial investment costs of the Absorption chillers outweigh the money saved through the reduction of electrical consumption by the electric chiller.

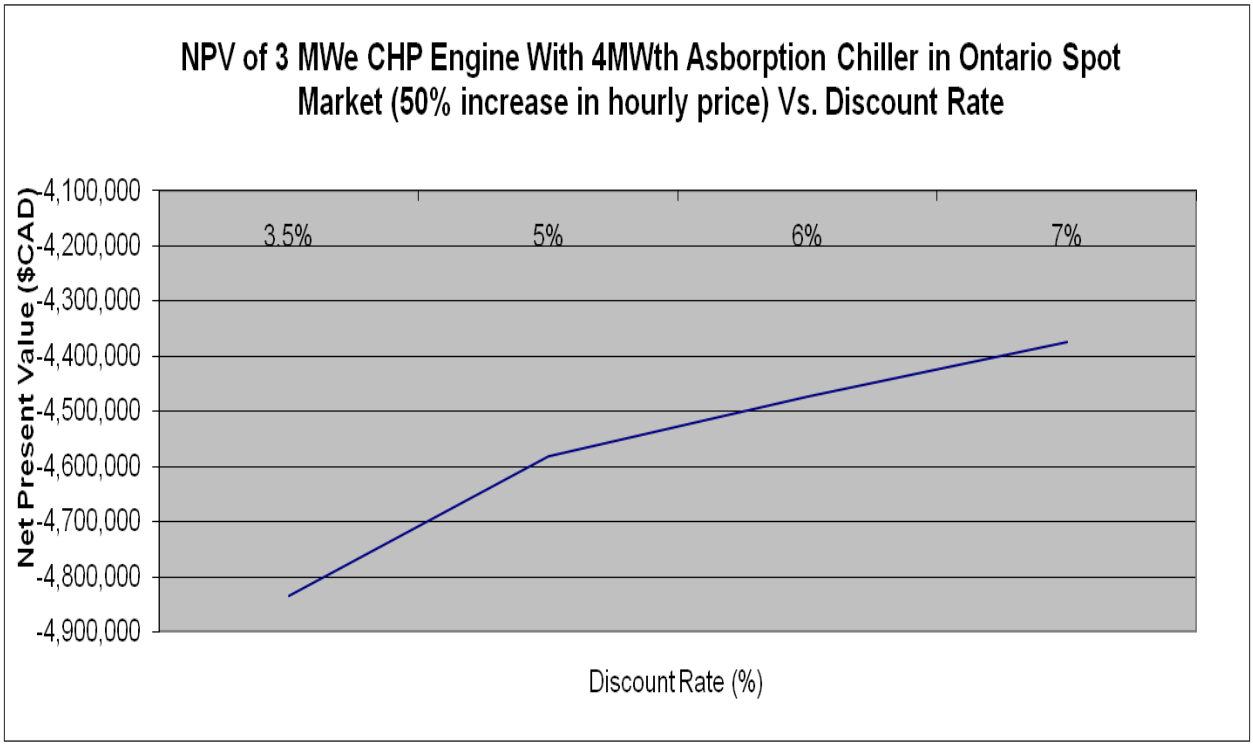
Figure 16. NPV of Alternative 4



Discount Rate Sensitivity Analysis of a 4 MWth Absorption Chiller Operating in the Ontario Hourly Spot Market When Spot Price is increased by 50%.

It can be seen in figure 17 and that the discount rate has a large impact on the net present value of the investment. A 3 MWe CHP engine with a 4MWth absorption chiller does not reach as positive value and as a result we see an inverse relationship to that the CHP engine and thermal storage from alternative scenario 3. For this scenario an increasing discount rate increases the NPV due to discounting future negative cash flows.

Figure 17. Discount Rate Sensitivity Analysis of NPV for Alternative 4



Discount Rate Sensitivity Analysis of the Optimal Size Absorption Chiller For Alternative Scenario 4 when Ontario Hourly Spot Market When Spot Price is increased by 50%

In table 11 it can be seen that the optimal size capacity of the Absorption Chiller varies depending on the discount rate applied in the net present value calculations. As the discount rate increases the optimal size of the Absorption chiller decreases and then becomes constant for the range of discount rates investigated.

Table 11 Optimal Absorption Chiller Capacities and Corresponding Discount Rates.

Discount Rate	Absorption Chiller Capacity	Net Present Value
3.5	4MWe	-4.766.459
5	3MWe	-4.559.404
6	3MWe	-4.405.702
7	3MWe	-4.266.525

Chapter 8: Discussion

The following chapter is a discussion of the various reasons why the market conditions are not suitable to CHP plants or for converting them to trigeneration plants. These reasons include spot market prices, underutilisation of the thermal storage, and improper methodology used for converting a CHP system to trigeneration.

Ontario Hourly Spot Market Electricity Prices

The spot market prices in Ontario are clearly too low for CHP engines to be economically feasible. There a many contributing factors at play such as an abundance of cheap nuclear and hydro electricity being produced. We have also been witnessing hours of negative pricing similar to the Danish market. This is due to increased wind capacity and also seasonal hydro production during snowmelt. Table 12 indicates the amount of hours the spot price was below zero and the other threshold values above which it would be feasible to operate a CHP engine.

Table 12. Spot Market Price Assessment

Assessment of Spot Price		
Hours below zero		
41		
Hours Below threshold value of 42$ (95% Boiler)		
Spot Price	Spot Price (+25%)	Spot Price (+50%)
7131	3800	1612
Hours Below threshold value of 39$ (90% Boiler)		
Spot Price	Spot Price (+25%)	Spot Price (+50%)
6448	2568	1266

However, it is inevitable that electricity prices will rise in the future as more renewable energy is installed, the transmission system is upgraded, and coal is phased out. Whether, the increase in the spot market price will be of the same magnitude as that of the price for end-use consumers (45% increase by 2014) is unknown. If so, then we could see CHP become more feasible and play a larger role in the future. If not, the government would be required to intervene with some kind of policy that either subsidizes CHP's or taxes other technologies such as boilers for not operating as efficiently.

These low spot market prices also make the conversion to absorption chillers unfeasible due to the fact that electric chillers are more efficient and cheap to operate under current market conditions.

The amount of money saved in electrical consumption when using the absorption chiller is not enough to justify the large initial investment that they incur.

One future opportunity is CHP systems powered by bio-gas. Bio-gas powered CHP plants are eligible for FIT (Feed-in Tariff) Contracts under the new green energy and green economy act. The feed-in tariff for bio-gas systems ranges from $104 to $195 CAD/MWh produced. This constant price would clearly make it feasible to operate a biogas CHP system pending it produces a minimum amount of MWh (OPA, 2010b).

Underutilisation of theThermal Storage

It is clear from the analysis that thermal storage units did not have a large impact on the NPV calculations. This could be for a number of reasons. First of all, even when the prices are above the threshold values, they might not be high enough to make larger scale CHP engines feasible. As the results showed, the smaller engines were consistently higher in terms of NPV when compared to the large engines. As a result the small engines only partially supply the total heat demand leaving no excess heat to go into the storage, rendering it useless.

Another reason could be that the hourly variance in spot market prices is very high and as a result the CHP engines do not operate consistently enough to ever fill the thermal store. Both of these cases would make the investment in thermal store unfeasible and as a result, having a system with CHP only may be the best approach for the current market conditions.

Improper Methodology: Conversion of Predefined CHP Plant to Trigeneration Plant with Absorption Chillers

As the results illustrate, converting an optimised CHP plant into a trigeneration plant is not as easy as adding absorption chillers. In order for the system to be optimised, the entire system must be considered. The capacities of the CHP and thermal storage tank need to be the proper size to provide optimal conditions for an absorption chiller. As a result, future research should be aimed at identifying a method for optimising trigeneration plants, rather than trying to convert a plant that is optimised for a different purpose such as supplying a heat demand only.

Chapter 9: Limitations

The results of this analysis indicate that it is not currently profitable to retrofit the existing boiler-only plant and produce electricity and heat simultaneously using CHP plants equipped with thermal storages under current market conditions in Ontario. It is also not profitable to convert an existing CHP plant to a trigeneration plant. However, there are various limitations associated with the analysis that may compromise the accuracy of the approach taken. The limitations in this analysis are associated with the assumptions made about data utilized as input for the model and also the discount rate used in the net present value calculations.

Limitations of the analysis associated with assumptions about the data used as input in the model include assumptions about the demand and also assumptions made about absorption chillers. The assumptions about the system demands could very well have had a significant impact on the

feasibility of the proposed investments. Changes in heat demand can have a significant impact of the feasibility of investments in CHP, as can changes in cooling demand on trigeneration plants. As a result, not using real system demand values reduces the validity of the analyses. Also, assumptions were made concerning absorption chillers which are not true in reality. For the purpose of this analysis it was assumed that absorption chillers have a constant capacity and efficiency, however both are variable in reality. Also it was assumed that absorption chillers do not consume electricity, which is untrue as a system of pumps and motors consume electricity while circulating the refrigerant. This also reduces the validity of Analysis #2, however, Absorption chillers were not feasible even when these assumptions were made, so the NPV would have been lower in reality, making them an even worse investment.

Lastly, the determination of a valid discount rate is a difficult task. As shown by the results, the discount rate utilised for performing net present value calculations has a very large impact on the profitability of an investment. With regards to trying to determine the optimal size of a CHP plant or trigeneration plant, the discount rate has a very large influence on what size is considered optimal. As a result there is a degree of uncertainty associated with making financial projections into the future, thus limiting the accuracy of the analysis.

Chapter 10: Conclusion

The government of Ontario recently released their new long term energy plan for the electricity system which will lead the province up to the year 2030. Many parties have opposed this new plan for a number of reasons, most formidably because of the costs it will impose on consumers.

Regardless of whether individual consumers or parties agree or disagree with the direction in which the plan takes, there a number of issues that all parties can agree upon. These issues include the fact that the province will still require significant upgrades to the transmission system and generation capacity moving forward (Chung, 2011). There are also significant costs associated with moving away from an energy system that utilises coal to one with an increased amount of renewable generation capacity (Dubinsky, 2011).

In order to reduce costs to consumers, CHP and trigeneration systems have been identified as technologies that can create cost savings through reduced resource consumption, reduced heating and cooling costs, reduced transmission losses and they decrease the cost of upgrading the transmission system as they can be connected to the low voltage distribution system.

The purpose of this research was to determine whether it was technically and economically feasible to operate CHP plants equipped with thermal storage in Ontario under current market conditions. A secondary goal of this research was to determine whether optimised CHP plants can be converted to trigeneration plants by adding absorption chillers.

Unfortunately, as the results indicate, both CHP plants equipped with thermal storage and the conversion of CHP to trigeneration systems is not economically feasible at the current time. This is highly due to the fact that spot market prices for electricity are lower than the marginal cost of operating a CHP plant during over 80% of the hours in the year.

In conclusion, In order for these systems to become feasible, the price of electricity must rise by approximately 50% or the government has to create some kind of legislation that will act as a catalyst for their adoption. Some examples of legislation could be to subsidize CHP plants in the same manner as they do renewable energy projects through feed-tariff schemes or to put a carbon tax on boiler-only plants such as the "Climate Change Levy" in the United Kingdom.

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APPENDIX 2: Tables Containing NPV Calculations Data and Sensitivity Analysis Data

Analysis #1(Reference Scenario 1 and Alternative Scenario 1)

Discount Rate (3.5%)	CHP Gas Engine Capacity (Mwe)										
Thermal Storage Volume (m3)	1 MWe	2 MWe	3 MWe	4 MWe	5 MWe	6 MWe	7 MWe	8 MWe	9 MWe	10 MWe	11 MWe
500	-1.090.398	-2.003.214	-3.226.297	-3.843.426	-4.863.929	-5.978.184	-7.104.682	-8.207.442	-9.312.276	-10.451.915	-11.593.835
1000	-1.226.898	-2.139.714	-3.362.797	-3.967.429	-4.920.993	-5.940.483	-6.964.418	-8.043.672	-9.122.073	-10.205.093	-11.362.435
1500	-1.363.398	-2.276.214	-3.499.297	-4.103.434	-5.027.352	-6.021.930	-7.049.389	-8.107.416	-9.180.727	-10.216.076	-11.288.074
2000	-1.499.898	-2.412.714	-3.635.797	-4.239.865	-5.159.026	-6.131.905	-7.130.963	-8.167.153	-9.211.635	-10.284.036	-11.375.740
2500	-1.636.398	-2.549.214	-3.772.297	-4.376.365	-5.292.831	-6.231.446	-7.239.395	-8.254.301	-9.292.264	-10.342.817	-11.407.374
3000	-1.772.898	-2.685.714	-3.908.797	-4.512.865	-5.428.410	-6.360.575	-7.349.912	-8.350.018	-9.376.072	-10.422.006	-11.496.307
3500	-1.909.398	-2.822.214	-4.045.297	-4.649.365	-5.564.092	-6.494.115	-7.451.664	-8.462.055	-9.468.357	-10.503.096	-11.562.839
4000	-2.045.898	-2.958.714	-4.181.797	-4.785.865	-5.700.822	-6.629.037	-7.576.600	-8.560.374	-9.581.730	-10.596.889	-11.637.951
4500	-2.182.398	-3.095.214	-4.318.297	-4.922.365	-5.837.127	-6.764.373	-7.709.104	-8.684.021	-9.692.396	-10.701.993	-11.734.704
5000	-2.318.898	-3.231.714	-4.454.797	-5.058.865	-5.973.293	-6.900.309	-7.844.429	-8.805.053	-9.790.497	-10.814.352	-11.836.652
500	-2.455.398	-3.368.214	-4.591.297	-5.195.365	-6.109.793	-7.036.947	-7.980.088	-8.935.184	-9.915.077	-10.928.497	-11.947.607

Analysis #1(Reference Scenario 2 and Alternative Scenario 1)

Discount Rate (3.5%)	CHP Gas Engine Capacity (Mwe)										
Thermal Storage Volume (m3)	1 MWe	2 MWe	3 MWe	4 MWe	5 MWe	6 MWe	7 MWe	8 MWe	9 MWe	10 MWe	11 MWe
500	-2.410.282	-3.280.679	-4.135.147	-5.019.584	-6.017.651	-7.113.789	-8.221.790	-9.308.230	-10.397.320	-10.451.915	-11.593.835
1000	-2.546.782	-3.417.179	-4.271.647	-5.137.425	-6.062.564	-7.057.430	-8.057.778	-9.117.072	-10.175.744	-10.205.093	-11.362.435
1500	-2.683.282	-3.553.679	-4.408.147	-5.272.140	-6.165.560	-7.134.270	-8.133.293	-9.175.391	-10.228.339	-10.216.076	-11.288.074
2000	-2.819.782	-3.690.179	-4.544.647	-5.408.191	-6.293.699	-7.240.778	-8.216.179	-9.230.256	-10.254.076	-10.284.036	-11.375.740
2500	-2.956.282	-3.826.679	-4.681.147	-5.544.403	-6.427.008	-7.338.096	-8.321.767	-9.314.674	-10.331.573	-10.342.817	-11.407.374
3000	-3.092.782	-3.963.179	-4.817.647	-5.680.880	-6.561.262	-7.465.463	-8.430.579	-9.407.212	-10.412.109	-10.422.006	-11.496.307
3500	-3.229.282	-4.099.679	-4.954.147	-5.817.380	-6.697.140	-7.597.114	-8.530.062	-9.517.648	-10.501.641	-10.503.096	-11.562.839
4000	-3.365.782	-4.236.179	-5.090.647	-5.953.880	-6.833.283	-7.730.285	-8.653.536	-9.614.333	-10.613.206	-10.596.889	-11.637.951
4500	-3.502.282	-4.372.679	-5.227.147	-6.090.380	-6.969.933	-7.865.127	-8.784.795	-9.736.977	-10.721.339	-10.701.993	-11.734.704
5000	-3.638.782	-4.509.179	-5.363.647	-6.226.880	-7.106.744	-8.000.072	-8.918.957	-9.856.305	-10.818.507	-10.814.352	-11.836.652
5500	-3.775.282	-4.645.679	-5.500.147	-6.363.380	-7.243.417	-8.133.704	-9.055.976	-9.985.388	-10.942.154	-10.928.497	-11.947.607

Analysis #1(Reference Scenario 1 and Alternative Scenario 2)

Discount Rate (3.5%)	CHP Gas Engine Capacity (Mwe)					
Thermal Storage Volume (m3)	2MWe	3MWe	5 MWe	10 MWe	15 MWe	20 MWe
1000	-1305484,434	-1797488,26	-3.044.634	-7.370.946	-12.318.288	-17.756.099
2000	-1578484,434	-2068795,201	-3.245.973	-7.320.272	-11.899.242	-17.063.526
3000	-1851484,434	-2341772,166	-3.505.002	-7.390.485	-11.936.561	-16.659.152
4000	-2124484,434	-2614726,096	-3.774.662	-7.520.888	-11.989.175	-16.786.918
5000	-2397484,434	-2887726,096	-4.044.023	-7.707.220	-12.078.922	-16.831.631

Analysis #1(Reference Scenario 1 and Alternative Scenario 3)

Discount Rate (3.5%)	CHP Gas Engine Capacity (Mwe)					
Thermal Storage Volume (m3)	2MWe	3MWe	5 MWe	10 MWe	15 MWe	20 MWe
500	345.256	543.559	97.887,01	-3.401.371,14	-8.899.452,92	-15.018.334,66
1000	208.756	426.259	208.757,96	-2.471.704,41	-6.896.812,67	-12.283.175,56
2000	-64.244	167.391	42.604,98	-2.261.664,20	-6.020.709,07	-10.938.601,27
3000	-337.244	-103.075	-205.160,37	-2.247.846,12	-5.918.610,03	-10.276.594,82
4000	-610.244	-376.110	-471.215,37	-2.323.564,38	-5.887.055,14	-10.320.144,96
5000	-883.244	-649.110	-734.943,86	-2.479.409,28	-5.911.866,45	-10.291.953,15

Discount Rate Sensitivity Analysis of a 3 MWe CHP Engine with a 500 m3 Thermal Storage Operating in the Ontario Hourly Spot Market When Spot Price is increased by 50%

NPV 3 MW CHP	Discount Rate			
Thermal Storage Volume (m3)	3,5%	5%	6%	7%
500	543559	113911	-138122	-366.337

Fuel and Electricity Price Sensitivity Analysis for Alternative Scenario 3

Gas and Electricity Sensitivity Analysis	
Electricity	NPV
-10%	-CAD 782.694
-5%	-CAD 40.572
0%	CAD 702.361
5%	CAD 1.463.465
10%	CAD 2.234.942
Gas	
-10%	CAD 4.174.152
-5%	CAD 2.434.532
0%	CAD 702.361
5%	-CAD 1.017.692
10%	-CAD 2.767.698

Analysis #2(Reference 3 (Optimised CHP from Analysis #1, Alternative 3 with added cooling demand and electric chiller) and Alternative Scenario 4)

Discount Rate (3.5%)	Net Present Value
Absorption Chiller Capacity	3MWe CHP
1MW	-6.202.800
2MW	-5.134.451
3MW	-4.821.425
4MW	-4.766.459
5MW	-4.962.917
6MW	-5.424.806

APPENDIX 2: Absorption Chillers

Description of Technology

Absorption chillers produce cooling via the utilisation of heat. The process utilises either ammonia or water mixed with salt as a refrigerant. The most commonly used salt is lithium bromide (LiBr). Absorption chillers are available in 3 different designs:

- Single-effect indirect-fired
- Double-effect indirect-fired
- Double-effect direct-fired

Single-effect indirect-fired chillers consist of a single generator and condense all of the gaseous (vaporized) refrigerant in a single condenser. They are considered indirect-fired as they require an external heat source (e.g. process heat or low temperature waste heat from CHP units) to power the phase change of the refrigerant in order to produce cooling.

Double-effect absorption chillers have two generators (one high temperature and one low temperature) that work sequentially in order to reduce the cooling requirement of the vaporized refrigerant, thus increasing efficiency and coefficient of performance. Indirect-fired double-effect absorption chillers require a higher input temperature than single-effect chillers (ie. high temperature steam), while direct-fired double-effect absorption chillers produce their own heat via combustion of natural gas, liquefied petroleum gas, propane, or oil.

The refrigerant loop for all three designs is in a state of partial vacuum in order to enable the refrigerant to vaporize at a low saturation temperature (boiling point). As a result, the internal pressure of absorption chillers can range from 0.1 to 0.01 atmosphere (atm). (Miller and Miller, 2006) and (Sakraida, 2009) The term "tons" of cooling is frequently utilised in the United States for measuring the cooling capacity of air conditioners and refrigeration equipment. 1 Ton of cooling capacity= 12,000 BTU = 3.516 kW. This unit is used because 12,000 BTU/hour or 3.516 kW/hour is approximately the amount of energy required to melt one ton of ice at 0°C over a 24-hour period.

Double-Effect Absorption Chiller Efficiency (Single-Effect included in actual paper)

Chiller efficiency is measured as cooling production per unit of fuel consumed. As such it can be measured in BTUh, or kWh of cooling. Chiller capacity can be stated in tons, BTU or kW.

The term used to indicate the efficiency of a chiller is coefficient of performance (COP). The equation for COP is Energy output (i.e. chiller capacity) divided by Energy input (i.e. heat input), where:

- Energy Output (BTUh or kWh of cooling produced) / Energy Input (BTUh or kWh of heat for absorption)

(e.g. 3.516 kW capacity chiller with a COP = 0.7 operating for 1 hour would require approximately 5.023 kWh).

Double-effect indirect-fired and double-effect direct-fired chillers typically have COP ranges of 1.19 – 1.35 and 1.07 – 1.18, respectively (Sakraida, 2009).

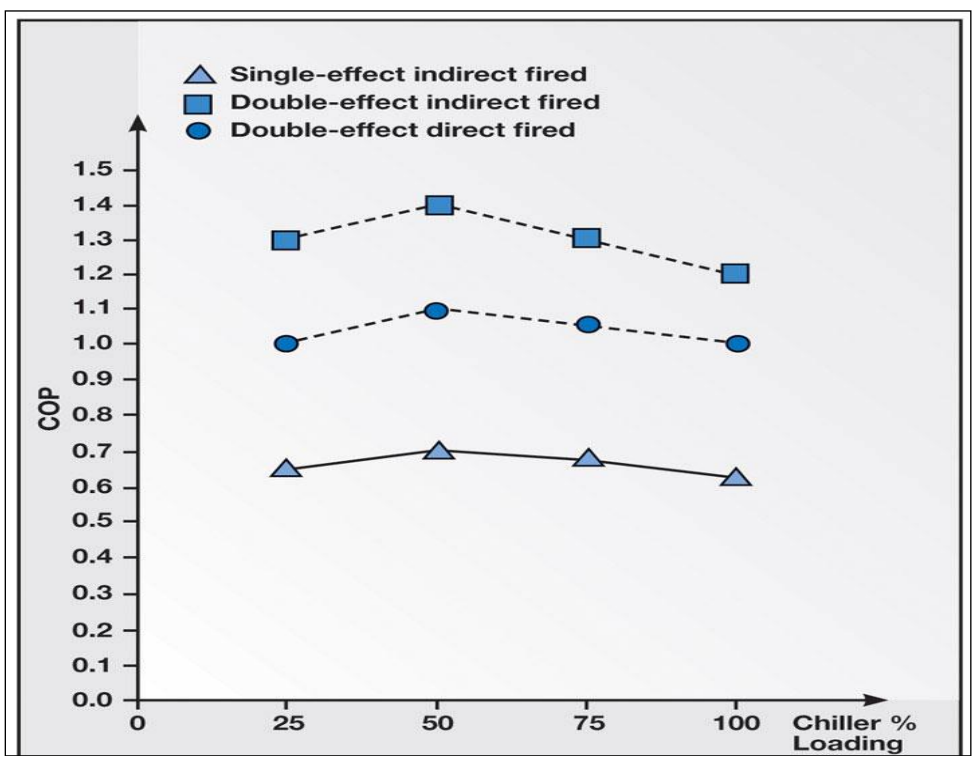
Factors Affecting Absorption Chiller Efficiency and Capacity

As with all energy conversion units certain factors can have an impact on the efficiency at which they operate. The performance of absorption chillers can be affected by three primary factors that include the percentage of the capacity being utilised, the temperature of the heat source and cooling source used to power the refrigeration cycle and the desired temperature of the chilled water.

Percentage of Capacity Being Utilised (% Load)

As indicated by Figure the coefficient of performance is dependent on the amount of the available capacity that is being utilised (% load). Ranging from low load to maximum load the COP increases up to a certain point (50% load for this example, however, it is product dependent), after which time the COP begins to decrease. This indicates that the optimum efficiency is realised at half load, and a sub-optimum level of efficiency is realised at all other loads (Gordon and Choon, 1995) and (Sakraida, 2009).

Figure 1

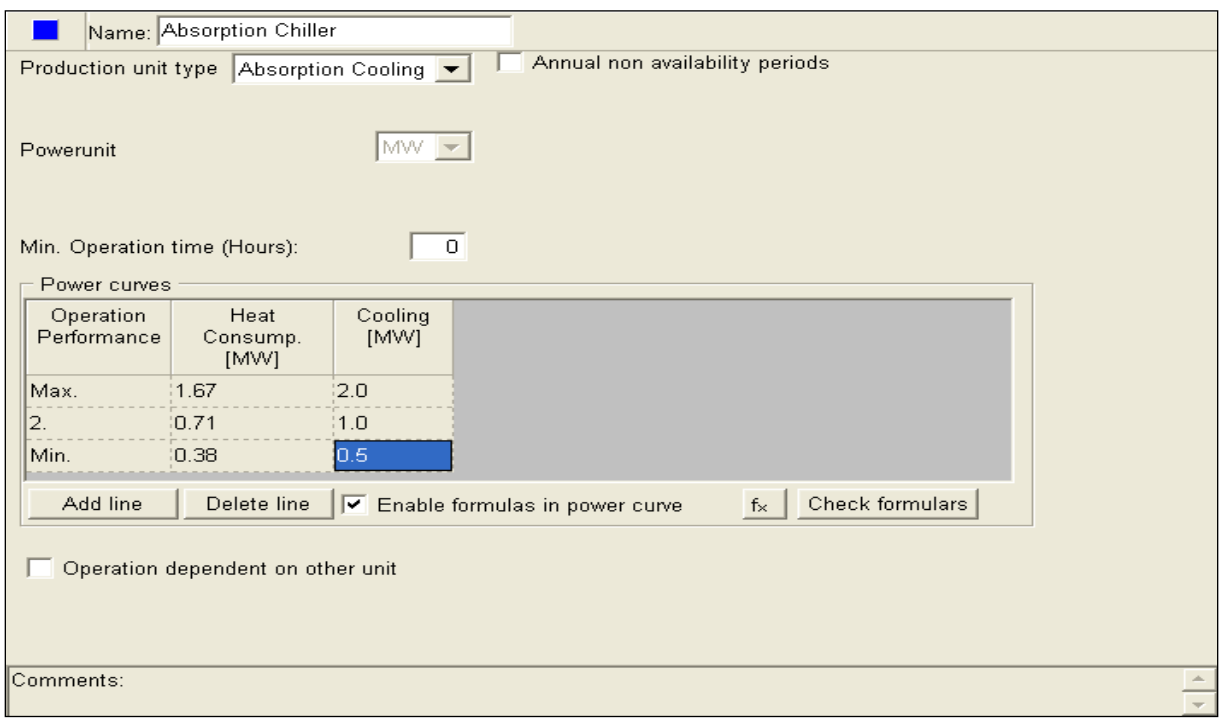


(Sakraida, 2009)

How to Enter Changes in COP that Result for Changes in % Load in the energyPRO Software Tool

In order to enter the fluctuations in chiller COP that result from changes in % load, you must break the curve into individual linear sections. Using the double-effect indirect fired chiller from Figure as an example, we can see that the power curve has two clear sections (one section with an incline between 25% and 50% load, and one section with a decline 50% to100% load). In order to get the program to calculate the proper heat consumption that corresponds to a given % load, you must specify a minimum and maximum load (for this example the minimum is 25% and the maximum is 100%). Assuming that this chiller has a capacity of 2MW, we can then utilise the given COP values from the graph to calculate the required heat consumption for different % load ranges. Figure is a print screen of the energyPRO interface that illustrates how this would be entered. At the start of the curve we have a minimum load of 25% equal to 0.5MW of cooling. At 25% load there is a COP equal to 1.3, which results in a heat consumption of 0.38MW. At the end of the first linear section we have a load of 50% equal to 1MW of cooling. The corresponding COP = 1.4, which results in a heat consumption of 0.71MW. The second linear section of the curve begins at 50% load (which has already been defined) and ends at 100% load equal to 2MW. At 100% load there is a COP = 1.2, which results in a heat consumption of 1.67MW. After specifying how the consumption of heat changes per unit of cooling produced depending on % load, the program will be able to calculate the corresponding heat consumption for any % load that falls within the range of 25% to 100%. The program treats each section as a linear relationship between % load and COP meaning that the heat consumption will change proportionately with an increase or decrease in % load over the predefined ranges.

Figure 2



Hot Water Inlet and Cooling Water Inlet Temperature

The temperature of the heat source (i.e. CHP waste heat or Boiler produced heat) that enters the chiller will also impact the efficiency of the unit. This is illustrated in figure 6, for a chiller capacity of 360 tons (1265 kW) and a constant chilled water output temperature of 44.6°F or 7°C. The cooling capacity factor, heat input factor and the heating capacity factor is dependent on the inlet water temperature (heating capacity factor should be ignored for this application as it pertains only to utilising the absorption heaters that Yazuki produces).
(Yazaki Energy Systems Inc., 2010)

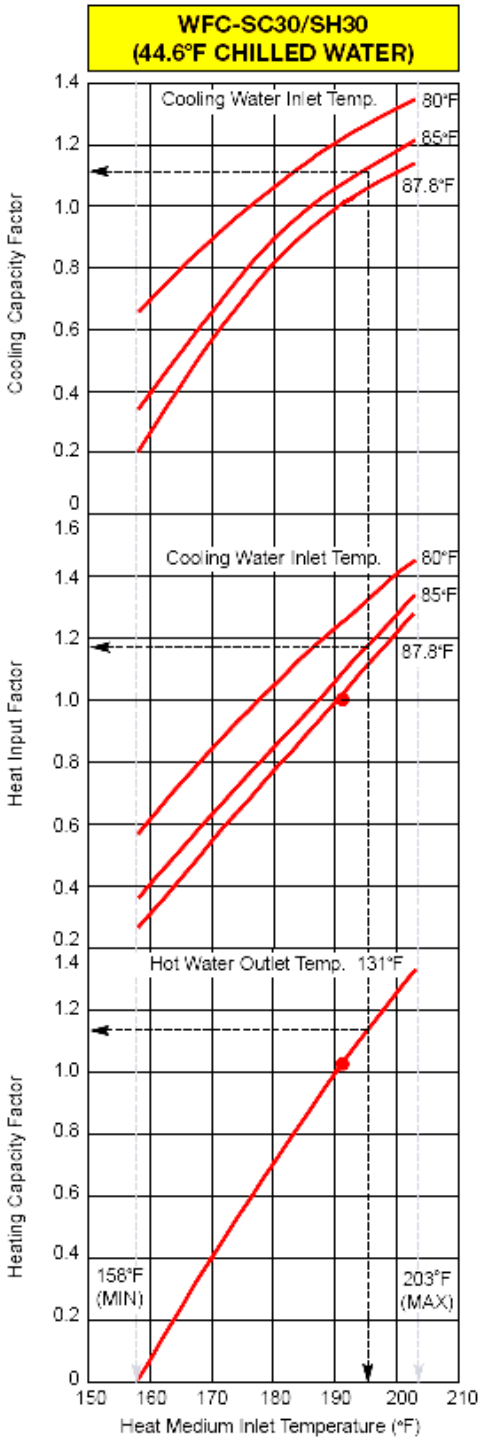
When the cooling capacity factor increases due to an increase in inlet hot water temperature, this increases the actual cooling capacity of the unit. Similarly, as the inlet hot water temperature increases, the heat input factor increases. As the heat input factor increases, so does the heat input utilised for cooling.

Conversely, the opposite can be seen for the inlet cooling water temperature. As the cooling water temperature increases, the cooling capacity and heat input factor decreases.

Both the cooling capacity factor and the heat input factor are utilised in calculating the actual cooling capacity and actual heat input for the chiller and are required to calculate COP and the required size of the cooling tower for heat rejection. The following graph

Figure 3 and examples of calculations performed can be found online at:
http://www.yazakienergy.com/waterfiredperformance.htm .
(Yazaki, 2010)

Figure 3



(Yazaki Energy Systems Inc., 2010)

Table 1 illustrates the changes in COP associated with changes in inlet hot water temperature. It illustrates that the relationship between the COP and hot water temperature is not linear, which supports 1. As the temperature increases so does the COP up to a certain point, at which point it begins to decline. The actual Cap (Capacity) and actual input are utilised to calculate COP. The equation for both is:

- Actual Cooling Cap = Cap Factor*Flow Correction*Std Cap (Nominal Capacity)
- Actual Heat Input = Input Factor*Flow Correction*Std input

(Yazaki, 2010)

Table 1 Changes in COP associated with changes in Inlet Hot Water Temperature

*****(Approximate capacity/input factor values measured by eye from**

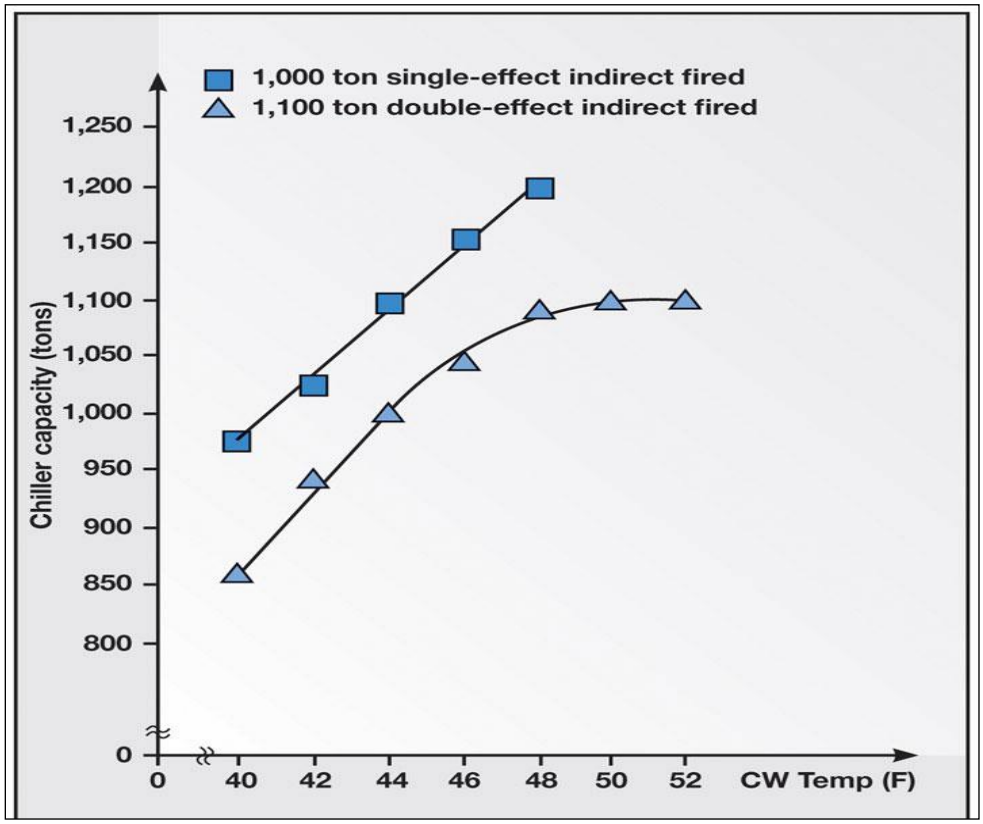
Inlet Hot Water Temp F°/C°	Type (Output)	Cap. Factor	Flow Correction	Std. Cap. (MBH)	Actual Cap (MBH)	COP
160/71	cooling	0.40	1	360	144.0	0.70
164/73	cooling	0.50	1	360	180.0	0.70
170/76	cooling	0.68	1	360	244.8	0.74
180/82	Cooling	0.88	1	360	316.8	0.74
190/88	cooling	1.02	1	360	367.2	0.70
200/93	cooling	1.19	1	360	428.4	0.67
Inlet Hot Water Temp F°/C°	Type (Input)	Input Factor	Flow Correction	Std. Input (MBH)	Actual Input (MBH)	COP
160/71	heat	0.40	1	514.2	205.68	0.70
164/73	heat	0.50	1	514.2	257.10	0.70
170/76	heat	0.64	1	514.2	329.09	0.74
180/82	heat	0.83	1	514.2	426.79	0.74
190/88	heat	1.02	1	514.2	524.48	0.70
200/93	heat	1.24	1	514.2	637.61	0.67

(Yazaki Energy Systems Inc., 2010)

<u>Chilled Water Outlet Temperature</u>

The temperature of the chilled water (i.e. The source of cooling) that exits the chiller will also impact the capacity of the unit. Figure 4 illustrates how the capacity of a 1000 ton single-effect indirect-fired chiller (3516 kW) fluctuates as the temperature of the outlet water fluctuates. As the water exiting the chiller increases in temperature, so does the capacity of the unit (Sakraida, 2009).

Figure 4.



(Sakraida, 2009)