Feasibility analysis of Polymer Electrolyte Fuel Cells for residential cogeneration applications in Australia

by

Mukul M Mahajan

Dissertation submitted to the School of Electrical Engineering in fulfillment of the requirement for the degree of

Master of Engineering
(Electrical Engineering)

Supervisor: Prof. Akhtar Kalam

School of Electrical Engineering
Faculty of Health, Engineering and Science
Victoria University

2006

STUDENT DECLARATION

"I Mukul M Mahajan, declare that the master by research thesis entitled "Feasibility analysis of polymer electrolyte fuel cells for residential cogeneration applications in Australia" is no more than 60000 words in length, exclusive of tables, figures, appendices, references and footnotes. The thesis contains no material that has been submitted previously in whole or in part, for the award of any other academic degree or diploma. Except otherwise indicated, this thesis is my own work".

Mukul M Mahajan Date: 21/08/06

Signature:

[redacted]

TABLE OF CONTENT

ABSTRACT

The objective of the thesis is to identify the technology and determine the economic feasibility for the implementation of the PEFC (Polymer Electrolyte Fuel Cell) stacks for Distributed generation in Australia.

The disposition of the thesis starts with an introductory background that highlights the need for a distributed energy system where Hydrogen acts as the main energy source. Subsequently a detailed survey of the availability of various types of fuels for the fuel cell powered stand-alone micro-grid is presented. The different types of fuels considered during the study include natural gas, methanol, ethanol, liquefied petroleum gas (LPG) and diesel. Both the availability and transport aspects for different fuels are surveyed. The coverage domain and the stage of development of the fuel infrastructure vary with its type.

The economic feasibility is determined by following a specified set of algorithm which consists of a series of calculations for varying system configurations. The configuration setup varies with the positioning and sizing of the system components like the fuel cell stack, the fuel reformer and the Combined Heat and Power (CHP) distribution network. The cost parameters and operating life for different configurations considered during the analysis are evaluated and then compared to the benchmark case where the power is bought from the grid and the heat demands are met by the conventional gas burner setup.

Two different cost approaches have been used; first one where the benefits of scaling up the system are considered and the latter one where a linear system cost approach has been used. Examining the two cost approaches, it is observed that it is important to consider the beneficial scaling factors. The calculated results are considered for two different supply strategies. In the first strategy, the entire heating load of the utility is met by the fuel cell system. Whereas in the second strategy, the heat demand is partly met by the fuel cell system and the gas burner acts as an auxiliary heat source. A software tool in Visual Basic editor linked to a Microsoft excel sheet has been developed for calculations with varying heat and power demands, the three system architectures, and the type of fuel used.

Subsequently an analysis on the effects of economic factors has been carried out with the help of the Visual Basic tool mentioned earlier.

The results indicate that the different system architectures are suited in various scenarios and the amount of heat and power loads. The results also show that the price of power from the grid has to increase considerably where the fuel cell systems can compete economically with the benchmark case. If a fuel cell system is to be installed, considerations have to be given to the desired economic configuration, the actual heat and power load curves for a domestic utility, costs and availability of the fuel supply infrastructure. The calculated results highlight significant variation in the fiscal and utilization costs for the different combinations calculated in the study.

ACKNOWLEDGEMENTS

I take this opportunity to express my appreciation to the staff of the School of Electrical Engineering at Victoria University for having provided the support necessary for me to carry out this Master of Engineering research degree.

My sincere gratitude is extended to Prof. Akhtar Kalam for his constant encouragement, learned suggestions, supervision and invaluable support in both academic and personal matters. This thesis wouldn't have been complete if not for his input, advice and enthusiasm to look into every single technical and presentation detail.

I also thank Dr. Cecilia Wallamark at Energy Processes, KTH for her assistance and advice provided to me for understanding the concepts of fuel cell system economics. I'm also grateful to Mr. John Osborne from Sustainable Energy Authority of Victoria (SEAV) for providing me with the valuable information regarding domestic energy system in Victoria. Special appreciation goes to Mr. Stuart Mcquire for allowing me to analyse his grid interactive house. Special mention goes to my friends in the School of Electrical Engineering for their help in construction of the calculation tool.

I'm thankful to my family, friends, workmates and students for their support outside the academic world. Last but not the least, I'll always be indebted to HE who dwells within us and inspires us to pursue the righteous path.

PUBLICATIONS

M. Mahajan, A. Maung Than Oo, A. Kalam, "Renewable Hydrogen based Distributed Power generation systems," in IEEE Proceedings of the ICECE, Bangladesh University of Engineering and Technology, Dhaka, 2004, pp. 172 - 176.

M. Mahajan, A. Kalam, "Economic evaluation of a fuel cell system for domestic application in Australia," Proceedings of the Australasian Universities Power Engineering Conference 05, University of Tasmania, Hobart, 2005, pp. 232 -236.

LIST OF TABLES

LIST OF FIGURES

LIST OF ACRONYM AND SYMBOLS

d_{cb}	Distance from the central cite to the building area	[m]
d_{fp}	Fuel pipeline length	[m]
d_{hep}	Heating pipeline length	[m]
d_{hp}	Hydrogen pipeline length	[m]
d_{sc}	Distance from fuel source to the central cite	[m]
f_{b}	Fuel flow to the burner	[LHV kWh_{fuel}/year]
f_{ref}	Fuel flow to the reformer	[LHV kWh_{fuel}/year]
f_{tot}	Total amount of fuel used	[LHV kWh_{fuel}/year]
p_{bought}	The total power bought from the grid	[kWh_{el}/year]
P_{demand}	The total power demand	[kWh_{el}/year]
P_{FC}	Power produced in the fuel cells	[kWh_{el}/year]
P_{sold}	The total power sold to the power grid	[kWh_{el}/year]
q_{b}	Heat produced in the burner	[kWh_{th}/year]
q_{demand}	The buildings heat demand	[kWh_{th}/year]
q_{hep}	Heat loss in the heating pipes	[kWh_{th}/year]
q_{sys}	Heat produced in the fuel cell system	[kWh_{th}/year]
N_{b}	Number of buildings	
$N_{FC, 250}$	Number of 250 kW fuel cells	
$P_{FC, comp}$	The size of the complementing fuel cell	[kW_{el}]
$P_{FC, max}$	The size of the fuel cell system	[kW_{el}]
$Q_{FC, max}$	Maximum heat supplied by the fuel cell system	[kW_{th}]
η_{b}	Burner efficiency	[Usable heat kWh/LHV burner fuel kWh]
$\eta_{sys, el}$	The fuel cell power efficiency	[Usable power kWh/LHV kWh_{fuel}]

η_{ref}	Reformer efficiency	[LHV $_{H_2\,out}$/ LHV fuel kWh]
$\eta_{sys,\,tot}$	Total fuel cell system efficiency heat)kWh/LHV	[(Usable power and kWh$_{H_2}$]
a_d	Annuity factor for the distribution net	
a_{FC}	Annuity factor for the fuel cell stack	
a_s	Annuity factor for the system	
C_{be}	Cost for the buildings and help equipment	[$]
C_{elec}	Total cost of electronics	[$]
$C_{el,\,bought}$	Cost for the bought power from the grid	[$/kWh]
$C_{el,\,sell}$	Cost for the sold power from the grid (negative)	[$/kWh]
C_{FC}	Total cost for the fuel cell	[$]
C_{fp}	Total cost of the fuel pipeline	[$]
C_{hep}	Total cost of heat pipeline	[$]
C_{hp}	Total cost of hydrogen pipes	[$]
C_I	Cost for land improvement	[$]
$C_{reformer}$	Total cost for reformer	[$]
C_{sys}	System cost	[$]
CC_{pipe}	Capital cost of pipeline	[$/kWh]
C_T	carbon dioxide tax	[$/kWh$_{fuel}$]
D_d	Depreciation time for the distribution network	[years]
D_{FC}	Lifetime of the fuel cell	[years]
D_s	Depreciation time for the system	[years]
ET	Energy tax	[$/kWh$_{fuel}$]
I	Interest rate	[%]
OM_{FC}	Maintenance and material costs to increase fuel cell lifetime	[$/year]
OM_{pipe}	Maintenance, personnel and material costs for pipeline system	[$/year]
OM_{sys}	Maintenance, personnel and material costs for system	[$/year]
$PR_{elec.}$	Price for the electronics	[$]
$PR_{el,\,bought}$	Bought Price for bought power	[$/kWh$_{el}$]

$PR_{el,\,sell}$	Price for the sold power	[\$/kwh$_{el}$]
PR_{FC}	Price for the fuel cell	[\$]
PR_{fuel}	Fuel price	[\$/kWh$_{el}$]
PR_{hep}	Price for heating pipelines	[\$/m]
PR_{hp}	Price for hydrogen pipeline	[\$/m]
PR_{kW}	Base cost of the fuel cell system	[\$/kW$_{el}$]
$PR_{reformer}$	Price for reformer	[\$]
TC_{pipe}	Total pipeline cost	[\$]
TC_{sys}	Total system cost	[\$]
TVC	Total variable cost	[\$/year]

1. INTRODUCTION

1.1 Introduction

Stationary fuel cell systems are often discussed as a future alternative for distributed generation. Both fuel cell technology and the advantages of distributed generation are being investigated. Stationary small scale fuel cell systems are at present in a demonstration phase. The advantages of fuel cell are high efficiencies and low emission levels. Additional advantages with the PEFC (Polymer Electrolyte Fuel Cells/ Proton Exchange Membrane Fuel Cell) are the high load following possibilities and near commercial state. At the outset, the present goals for the manufacturing cost of a fuel cell system for 2005 to 2015 are set to reduce from 1500 US\$/kW$_{el}$ to 400 US\$/kW$_{el}$ [1]. However, fuel cell systems on the market are more expensive than this goal but prices are decreasing as research and development continues. Investigations into the total economy of stationary fuel cells have been performed for different locations around the globe. In United States for instance, it is not economically feasible to implement fuel cell system for and average building but feasible in parts with high electricity/gas price ratios [1]. Study of the economy of stationary fuel cell systems conducted in Japan indicates that stationary fuel cell installations are economically not suitable for a Japanese residence [2]. Feasibility analysis conducted in Sweden suggests that the price of fuel cell components has to decrease considerably before fuel cell can be considered to be a feasible option for residential cogeneration application [3].

Market surveys and detailed study of the fuel infrastructure would be crucial for the evolution of distributed hydrogen economy in the Australian setting. This study is an effort to identify the prerequisites for the stationary setup of the Hydrogen fuel cell systems in domestic applications. The analysis is done during the period where it is time in Australia and other countries to make a choice of fuels for future needs and evolve an infrastructure to exploit the resource in a sustainable way.

1.2 Background

Energy efficiency and clean distributed generation technologies are an important issue in regards with comprehensive energy policy debate. Evolution of a sustainable energy infrastructure in form of decentralized power and heat supply network has the potential to eliminate the energy related crises and the associated issues regarding inherent drawbacks of the conventional centralized grid supply system [4]. An alternative is to decentralize the parts of the infrastructure and distribute fuel to the consumer utility [5]. Briefly, the merits of deregulated power generation can be outlined as [6]:

- Greater system efficiency due to elimination of transmission and distribution losses;

- Independence from the fluctuating and non-reliable centralized grid supply;

- Provision for on-site co-generation facilities thereby providing a supplemental utility;

- Generating the otherwise economically non-viable infrastructure for the implementation of renewable energy sources;

- Reduction of dependence on fossil fuel producing economies and thereby rendering isolation from inflation of fuel prices;

- Smooth incremental curve of the generating capacity within a developing network. This is in contrast to the centralized generation where lump-sum capital investment and setup is desired;

- Appropriately designed distributed inverters can actively cancel or mitigate transients in real time at or near the customer level improving grid stability;

- Decentralization in turn boosts the Hydrogen economy where cost of piping the energy in the form of Hydrogen is reduced to 25% as against the transmission of electric power. When distributing energy over distances exceeding approximately 400 km, the costs would be even lower.

There is currently an array of deregulated power supply sources varying in the generating capacity, cycle efficiency, capital investment costs and commercial availability status as can be illustrated in Table 1. The transformation of modern distributed generation system from traditional systems has been in the location and size (1 to 10 MW) of the plant layout and the technology implemented within.

Table 1: Statistical comparison of deregulated power generation systems [4]

	Status	Size	Cycle Efficiency	Installed Costs $/kW	Total Costs $/kWh
Steam Turbines	Commercially Available	50 kW- 200 MW	12 to 38	400- 1000	0.03 to 0.06
Reciprocating Engine	Commercially Available	20 kW- 20 MW	28 to 38	500- 1400	0.06 to 0.09
Combustion Turbines	Commercially Available	500 kW- 500 MW	21 to 65	600- 900	0.04 to 0.08
Micro turbines	Commercially Available	30 kW- 300 kW	20 to 28	600- 1000	0.06 to1.0
Fuel cells	Commercially Available	5 kW- 3 MW	36 to 60	1900- 3500	0.06 to 0.10
Photovoltiacs	Commercially Available	1 kW+	10 to 20	5000- 10000	0.10 to 0.20
Wind Turbines	Commercially Available	750 kW+	13 MPH+	1000- 1500	0.10 to 0.20

It can be inferred from Table 1 that the concept of using fuel cells provides the ideal solution for decentralized markets due to the fact that it has the highest cycle efficiency. Another advantage that can be derived from Table 1 is that the energy system can be easily upgraded to a higher kW capacity just by increasing the number of fuel cell stacks. An emerging energy convention in the form of Hydrogen infrastructure is seen as an evident solution for the future energy system provided the installation costs are brought down to comparable levels of the conventional system's costs [7, 8].

1.3 Motivation

Fuel cells for transforming energy into electricity occupy a firm place in the financial scenarios because of their reputation of intrinsically high efficiency [9]. The fuel cell system not only facilitates deregulated renewable power generation but is also the most energy efficient and concentrated source of power having high energy density. Such a system is not only emission free but also eliminates the complexities of power generation. It provides a flexible solution for remote area power systems where it invests in energy storage systems using Hydrogen. A fuel cell is an electrochemical device that converts the chemical energy of a fuel directly into electrical energy. Intermediate conversions of the fuel to thermal and mechanical energy are not required. Figure 1 indicates the flows and reactions in a simple fuel cell. Unlike ordinary combustion, fuel-rich and oxidant (typically air) are delivered to the fuel cell separately. Electrochemical oxidation and reduction reactions take place at the electrodes to produce electric current. The bi-product of the cell reaction is water.

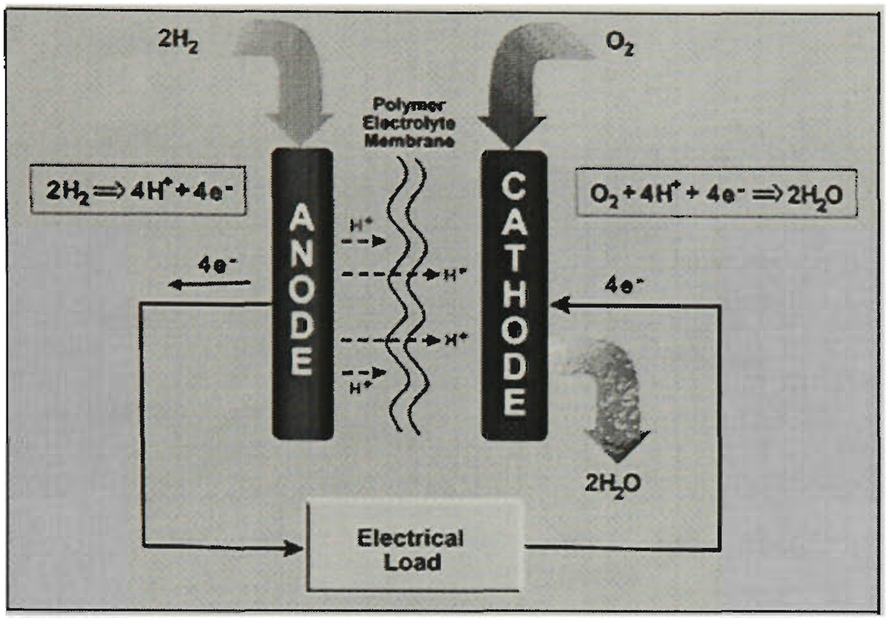


Figure 1: Schematic view of a fuel cell [4]

The key features of the fuel cells that make them such a viable tool for the evolution of a decentralized market are [10, 11]:

- High efficiency: Electrical efficiencies of stationary reformate PEFC systems are seen in the range of 13% to 35 % Lower Heating Value (LHV). This indicates that a fuel cell system gives higher efficiency than competitive techniques independent of the system size (Figure 2);
- Low chemical, acoustic, and thermal emissions;
- Siting flexibility;
- Reliability;
- Low maintenance;
- Excellent part-load performance;
- Modularity;

- Fuel flexibility enabling hydrogen production from solar and/or wind hybrids and even from biomass gasification as well as the reformation of hydrogen carrier fuels such as natural gas and methanol.

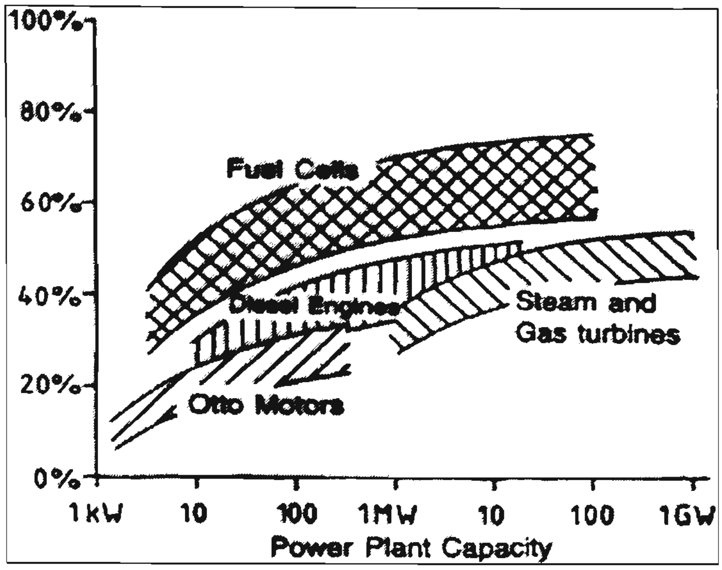


Figure 2: Comparison of power plant efficiencies[4]

The case for moving towards a Hydrogen based economy meets the required pre requisites for being desirable as the way to protect the environment and provide a stand alone energy system [1]. The energy vector in the form of Hydrogen could be obtained by reforming other fuels or electrolysed from water by passing electric current through it [12]. Bio-chemical processes such as anaerobic reactions such as fermentation and photolysis of water using algal vegetation can also act as the source of Hydrogen [13].

1.4 Problem statement

Storage and transport of the Hydrogen gas is a largest problem if the international community is to make the giant transition [14]. Thereby the transition has to be a gradual one where the prerequisites for energy carriers in the form of methanol, ethanol, dimethyl ethers and natural gas reformates are required to be identified. A detailed analysis of the algorithm and conversion efficiencies of obtaining Hydrogen rich fuels from natural gas and biogas has been carried out in the earlier research [7, 15]. Most feasible lifecycle aspects and choice of fuels for tractive applications has been dealt with at the beginning of the century [16, 17]. Despite the inconsistency of the results varying with the assumptions and limitations the highlighted energy infrastructure can be seen to emerge from natural gas reformate at the outset. Such an infrastructure is likely to be seen in parallel with the existing power grid and for both stationary and tractive applications. Stationary power application of fuel cells represents the biggest opportunity to truly impact the world's environment in comparison to the tractive applications. At its terminal state of deployment, fuels fed by rich fuels could produce all the energy needs of an average residence [1]. Worldwide protocols in the quest of the green house gas reduction are considered as major driving factors assisting the development of distributed infrastructure [18]. The fiscal scenarios and the security of the supply are also the key players in such a transition [19].

Australia faces similar challenges from the rest of the world in relation to the growing concerns about energy security and green-house emissions. Australia is therefore in a better position than as compared to many other nations that have limited resources of their own and are thus far more at risk of disruptions to power [20].

1.5 Approach

The objective of the thesis which is the identification of economic feasibility is achieved through four distinct stages. Initially the power and domestic heating infrastructure available in the area under feasibility consideration is outlined. Secondly a survey of the available fuels in Australia today that can be used for distributed generation has been presented. In the third stage of the thesis, the costs for a power supplying enterprise to supply heat and power to a specific set of domestic loads is calculated. Finally the cost comparison for three distinct system architectures has been performed and its sensitivity analysis with variation of input parameters is carried out. The three system architectures are compared to the benchmark system where the heat is produced by the burner and the power is brought from the centralized power supply network. To calculate the system costs, natural gas is considered as the actual source of fuel for conversion to the Hydrogen rich reformate. The impact of various parameters such as the number of residential blocks, power costs, fuel costs, operating efficiencies and the cost of the distribution network on the total system cost has been analyzed. The result of the standard case with certain predefined parameters is presented in the report. The effects of variation of certain parameters on the derived results have also been analyzed. The capacity and operation of the fuel cell system depends on the consumers' power and heat demand which eventually depends on the surrounding climate. The most favorable demand approach for residential cogeneration system is determined.

1.6 Organization

Chapter one of the thesis highlights the introductory summary of the study which has been undertaken to determine the feasibility of the fuel cell for residential cogeneration in Australia. It further explains the overall structure of the whole thesis. The power and heat infrastructure survey as detailed in the second chapter is a review of the current available generation, transmission and distribution network of electricity and the different ways of space and water heating systems being implemented in the part of Australia that is under feasibility consideration. The third chapter viz. the fuel investigation deals with the first objective of the study. The most likely fuels used in distributed generation setup such as natural gas, biogas, hydrogen, methanol, ethanol, Liquefied Petroleum Gas (LPG) and diesel have been described in the report. Just a brief introductory analysis of LPG and diesel infrastructure has been carried out. The survey can be classified in terms of the infrastructure setup, technical database and pricing parameters. The fourth chapter summarizes the different assumptions and the input data considered in the calculation. Different configurations with their respective assumptions have been elaborated in detail in this chapter.

The actual calculation of the total annual costs for different architectures is done in the fifth chapter. A software tool developed in Visual Basic has been used for the calculation of the cost parameters. The fuels other than natural gas can also be considered by modifying certain parameters of the tool for the fiscal analysis. The cost for a stationary PEFC system has been calculated and compared to the cost of the benchmark system. The cost calculated is the annual cost to supply a residential building with its power and heat demand. Two discrete supply strategies have been implemented. In the first approach, the heat demands for the domestic load are met by the fuel cell system as a whole. In the second approach, the fuel cell system meets the base loads while the burner supplies the additional heat demand. The building's total annual power and heat loads have been calculated from the readings taken from an existing building in the state of Victoria. As a case study, the building considered is a grid interactive house located in the Melbourne suburb, Victoria. It has been assumed that the analyzed fuel cell system and the fuel source are located in the same part of Australia. Chapter 6 elaborates results and discussion.

Finally to conclude, the most economical configuration is determined and the certain external factors have been mentioned that will monitor the reduction of the total annual cost of the residential cogeneration systems powered by PEFC systems.

2. POWER AND HEAT INFRASTRUCTURE

2.1 Power Distribution

The electricity supply industry in Australia was organized on a state basis with initially little transfer of power between the various states other than Victoria and New South Wales [21]. However national electricity market commenced in 1998 whereby the bulk consumers (distribution and retail operations) can buy power from the interstate generation companies located in any south eastern state. States of New South Wales, Queensland, Victoria and South Australia were initially bundled together for wholesale operations. The Basslink project wherein the States of Tasmania and Victoria have been interconnected by a 500 kV High Voltage Direct Current (HVDC) submarine cable has made interstate wholesale operations between utilities in other states and the hydroelectric generators in Tasmania feasible [22].

The four electricity supply operations viz. generation, transmission, distribution and retail were initially controlled by a single monopoly business. The restructuring of the electricity supply industry has opened the generation business for privatized competition. The electricity transmission business in Australia has largely been a single monopoly business since [23]:

- The critical importance of electricity to industrial development,
- The need for co-ordination in the development of a system as highly interconnected as the electricity supply industry and,
- The large size of capital investments required.

The distribution business is a domination of regional bodies whereas retail operations are again open to private competition. Similar to the overall national electricity market, the Victorian power infrastructure is not speaking into four distinct stages viz. generation, transmission, distribution and retail. The generating companies own the power generation plants and compete to sell power to the national electricity market.

The interstate grid connections and the main state power grid consist of 330 to 500 kV overhead transmission network. The regional networks that generally operate at the voltages of 66 to 110 KV convey power from the main electricity grid to local networks and sometimes to high utilization utilities. Before the end user receives the power, it is transformed to 230 volts rms. The transmission network in Victoria is owned by SPI PowerNet.

The 500 KV diffusion route is constrained from Portland to Traralgon across the Melbourne urban settlement. The majority of the intrastate network consists of a 66 kV sub transmission network [21]. Figure 3 gives a brief overview of the transmission and distribution network across the Victorian state.

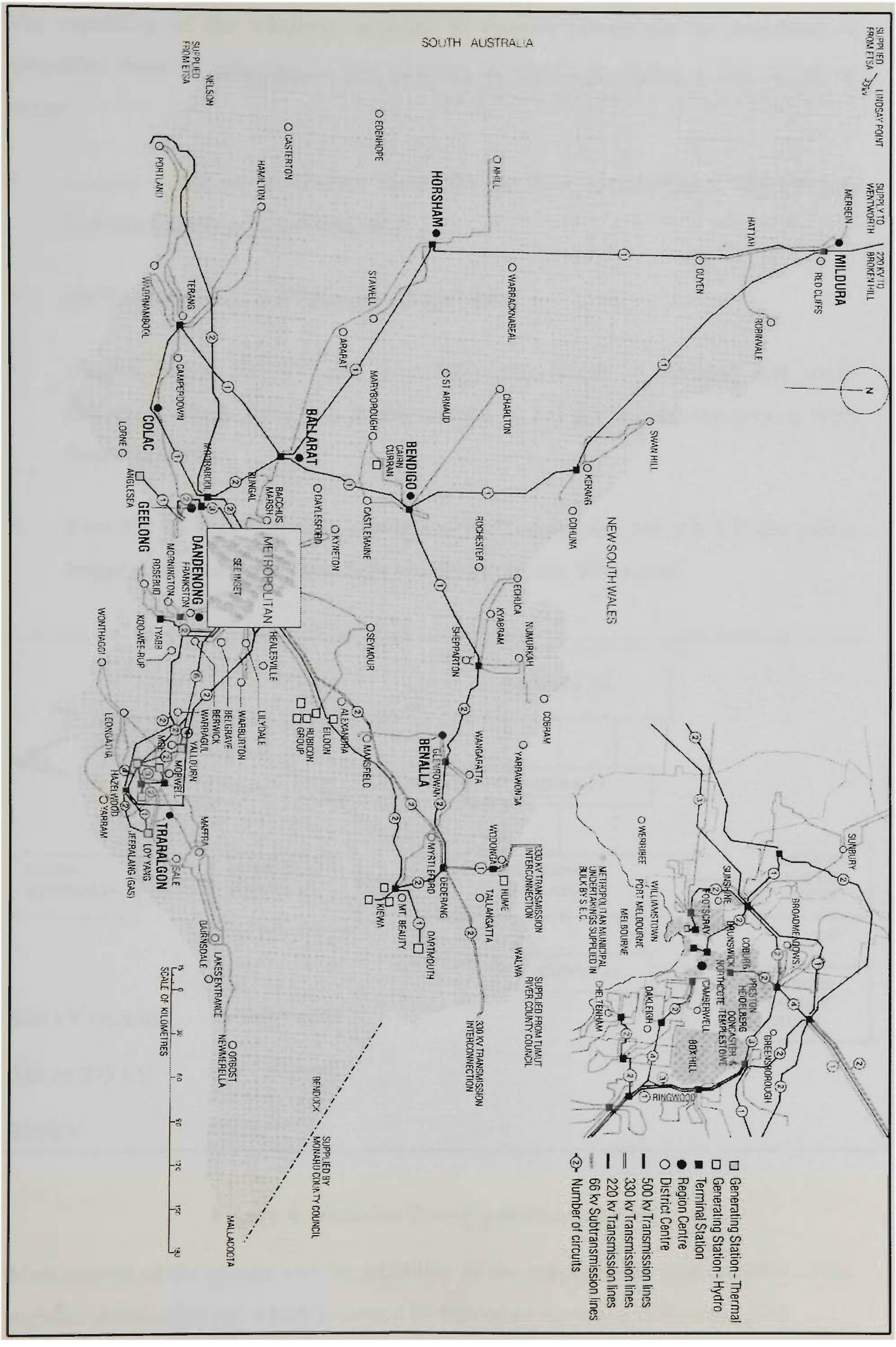


Figure 3 :Power transmission network in Victoria [21]

The capability of the Victorian network to transfer power can be described in simplified form by referring to four sections as shown in Figure 4 and described below:

- Latrobe valley to Melbourne, three 500 kV lines in addition a 220 kV line between Hazelwood and Rowville;
- Six Latrobe valley to Melbourne 220kV lines;
- Double circuit 500 kV line west from Moorabool to Portland and south Heywood, where there is a transformation to 275 kV for interconnection with South Australia;
- Two 330 kV lines between snowy and Melbourne plus one 220 kV line and a longer rural grid connection between Dederang and Melbourne.

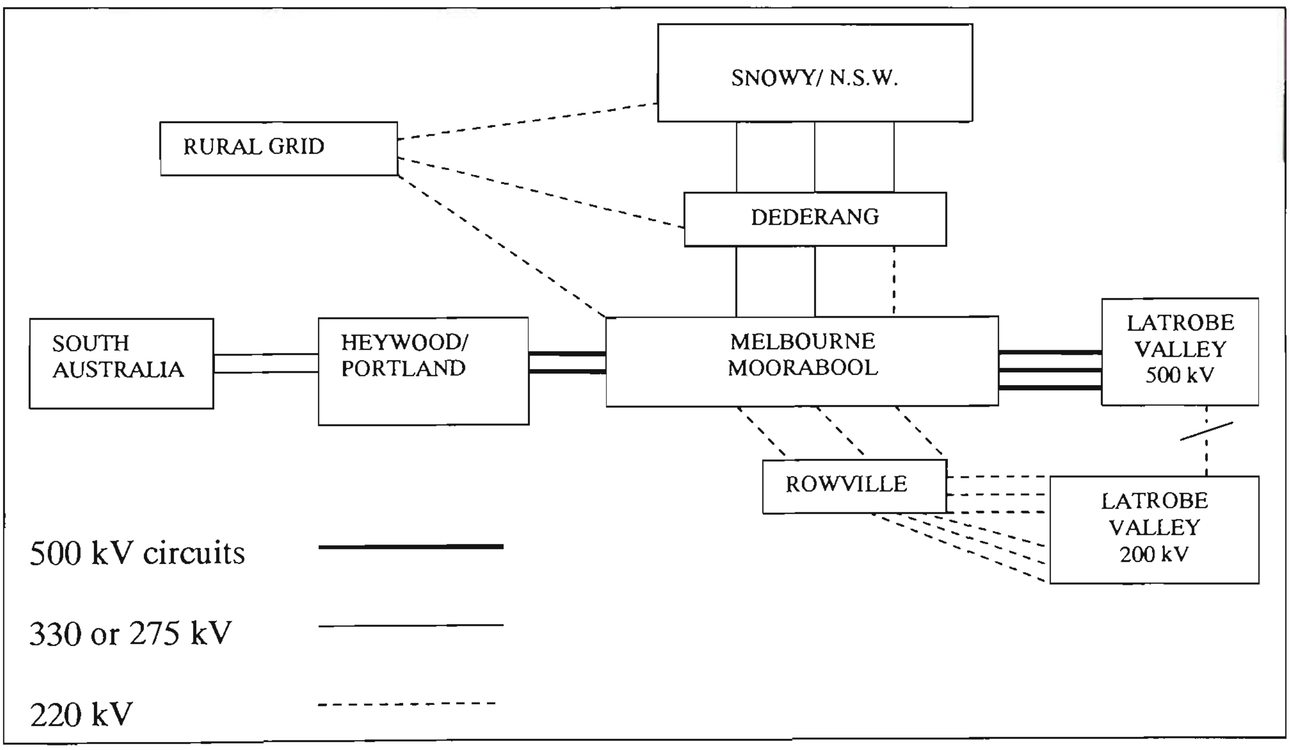


Figure 4: Victorian Power grid structure [24]

Maintenance of the quality and the reliability of the supply is the responsibility of the regional distribution net which is owned by Powercor Australia in Victoria [23].

The retail business has been privatized for the evolution of competitive markets. Privately owned companies such as Origin energy, Energy Australia, TRU and AGL buy wholesale power from the national electricity market and sell it to end-users at a tariff regulated by the national electricity market.

As of January 2002 Australia had power generating capability of 45.3 million kW. Approximately 84 % of this capacity was thermal while 14 % was through non conventional energy sources. Western and southern regions of Australia mostly depend on natural gas to fuel their energy supplies. The Energy Supply Association of Australia (ESAA) has predicted that consumption will grow rapidly in coming years rising to 206 bkWh by 2008 with Queensland, New South Wales (NSW) and Victoria being the main consumers [25].

With the supplementary interconnections of grids, there will be more use of natural gas for electricity generation than if there are no new interconnections. Nearly all the anticipated increase in gas utilization in states other than Victoria has been in power generation. However the black and brown coal are and will remain the mainstay for electricity generation as illustrated in the Table 2.

Table 2 gives an overview of the share of electric energy generated in PJ/year for the various available fuels and energy resources with the projections until 2020.

Table 2: Electricity generated annually through different fuel sources (PJ/year) [26]

	2005	2020
Brown coal	91	25
Gas	63	103
Hydro	8	8
Solar thermal	0	58
Wind	6	6

The housing utilization of power accounts for nearly 27 % of total electrical energy utilization which has rapidly increased by nearly 80 % from 1980 to 2000. These trends point out colossal expected surge in green house gas pollution from power use in the housing segment. Simultaneously, Australia has amongst the lowest residential power prices in the world, therefore there is little enticement to lessen energy utilization [27].

Figure 5 shows that Victoria consumed 39,115 Giga watt hours (GWh) of electricity in 2000.

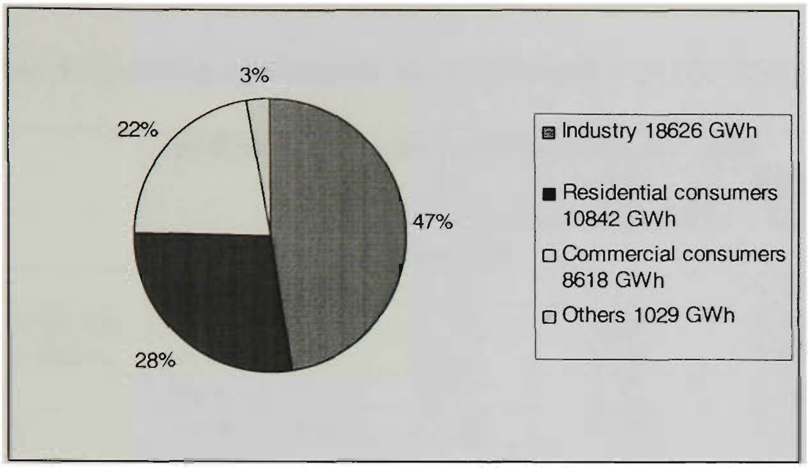


Figure 5: Share of annual electricity consumption in 2000 by various sectors in Victoria [27]

In 2002, Australia accounted for 1.7% of the global carbon di oxide emissions [25]. With respect to the Kyoto agreement, Australia was one of the three countries permitted an increase in its carbon emission than what was in the year 1990 [7].

The total price of electricity charged to the consumer consists of:

1. Network tariff as mentioned in the Table 3 for general supply consumer in Victoria;

2. The energy cost;

3. Wholesale market operation costs;

4. Costs on transmission and distribution losses;

5. Costs on retail operations and marketing.

Average electricity retail prices in Victoria as on the end of financial year 2003-2004 as under:

Residential: 16.12 c/kWh.

Non-residential: 8.65 c/kWh

Total average: 10.64 c/kWh

Table 3 gives the variation in the domestic electricity prices for Victoria with a variation in annual energy consumption in KWH.

Table 3: Variation of domestic electricity prices in Victoria [28]

Region	Tariff Name	Consumption-kWh per year			
		600	1200	2500	3500
		Average electricity prices – Cents/kWh (GST inclusive)			
Melbourne- city	Network price	8.76	6.80	5.78	5.51
Melbourne- Nth suburbs	Network price	10.33	8.08	6.90	6.59
Melbourne- SE suburbs	Network price	10.97	8.50	7.22	6.89
Eastern Victoria	Network price	13.77	9.70	7.58	7.02
Western Victoria	Network price	13.20	10.08	8.46	8.03

2.2 Distributed generation

With dispersed generation, electricity is produced at a short distance from a consumer in a decentralized generating unit. As mentioned earlier, generation of electric power close to the consumers has significant advantages rendered to the consumer as well as to the utility provider. The environmental and economic aspects with dispersed generation are also vital.

However, the disadvantage or the problem with dispersed generation can be the one where an costly and sophisticated control system may be required in a case of net-metering where consumer trades power with the grid.

One more disadvantage in most of the situations is the high fitting price in comparatively small scale power production. With distributed generations, there is no need of long distance power transports, but there is a need for long distance fuel transports [29].

2.3 Heating infrastructure in Australia

Roughly 80 % of the Australian housing settlements have some form of space heating system. The bulk of the Australian states has a comparatively mild type of weather and hence requires space heating for a partial period over wintry weather.

Electric heaters are naturally preffered because of the small capital investments in these locations. An uptrend in the electric space heating demands is probable with the prologue of quash cycle air conditioners [30].

Natural gas provisions about 30 % of the total domestic energy in Australia chiefly intense around space heating/cooling (40%), water (45%) and cooking almost 30%. The share of natural gas for heating and cooking utilities has taken a significant uptrend in recent years [31]. As shown in the Table 4, gas accounts for 33% of domestic water heating for Australia as a whole and around 60 % in Victoria.

Table 4: State wise variation in percentage share of domestic heating through different sources in Australia [32]

	Electric	Gas	LPG
NSW	78	19	1
Vic	38	59	2
Qld	82	7	6
SA	49	46	3
WA	37	41	7
Tas	96	0	1
NT	45	0	2
ACT	79	20	0
TOTAL	61	31	3

It can be inferred that at present Victoria accounts for two thirds of the Australian household gas markets. Table 5 compares the running costs of the different types of heating systems.

Table 5: Running costs of various heating systems [33, 34]

Energy supply	Price	Energy content	Efficiency	Cents/MJ
Firewood	$ 120/tonne	16MJ/Kg	60%	1.25
Natural gas	3.81 cents/unit	1 unit=3.6 MJ	70%	1.51
Electricity	12.75 cents/kWh	3.6 MJ/kWh	100%	3.54
LPG	64.9 c/L delivered	36.5 MJ/L	70%	2.54
Solar with electric boost	$ 2.15/ 1000 L	NIL	249%	-
Solar with gas boost	$ 1.20/ 1000 L	NIL	200%	-

Australia has an recognized domestic solar water heater business and is one of the worlds leading exporters with systems installed in over 70 countries. The most common application is in the form of thermosyphon system. Domestic water heaters classically require some electrical boosting to ensure the permanence of the supply. Gas boosted systems have also become accessible but at relatively higher capital investment [35].

kindling has been an imperative resource of heat energy supply for regional Australian settlements. Around 1/5th of the residential sector uses firewood regularly or occasionally for heating. In Australia, most wood fuel is obtained from the land clearing operations on a clandestine land [33].

2.4 Heat pipelines in the studied system

Three configurations of heat and power production (described in detail in the chapter 5) have been considered in the studied system. In both the cases "local" and "split", no major heat pipelines are necessary due to location of heat production. Heat is produced in or in vicinity of a building. In the configuration case central, the heat is produced at a distance from a building, which gives rise to a need for heat pipelines. A pipe of dimension 40-mm is chosen to supply the necessary amount of heat. The heat losses from a standard pipe with a dimension of 40-mm are approximately 20 W per meter. For the twin pipes used in this study, a heat loss of 15 W per meter is assumed [36]. The price of pipes for the studied conditions is assumed to be 425 $/meter. Even though, a slightly higher pipe dimension is chosen for a higher capacity i.e. 50-mm, it is possible to assume that the price is the same as for the 40mm pipe. An economic lifetime of 40 years and no maintenance are assumed for the heating pipelines.

3. FUEL INVESTIGATION

3.1 Natural gas

3.1.1 Natural gas facts

Natural gas is a fossil fuel that is formed during the course of millions of years deep beneath the crust of the earth. Fossil fuel is formed through the decomposition of organic material. The earths total natural gas reserves are quite extensive with large assets spread all over the world. With the rate of current consumption and the existing and possible reserves of natural gas, the assets are projected to last for approximately 250 years. Currently, Australia retains 2.407 trillion cubic meters of natural gas reserves [37].

Due to the high pressure, no external energy is needed to extract the gas from the well and the pressure can even be sufficient to supply customers far from the main pipeline grid. When the gas has to be transported at large distances, there is a need for an external energy input for example, compressors along the pipeline. Natural gas is mainly constituted of methane (85-99%) which exhibits the basic hydrocarbon molecular structure. Higher hydrocarbons such as ethane, propane and butane exist in small amounts. Other components that exist in small amounts are carbon dioxide, nitrogen and sulfur. The composition of the different components in natural gas depends on where in the world it is extracted. The percentage breakup is elaborated in Table 6.

Table 6: Facts of Australian Natural gas [38]

Composition		**Fuel data**
Methane	88% (mol)	LHV 40.4 (MJ/Nm3)
Ethane	5.5% (mol)	HHV 44.6 (MJ/Nm3)
Propane	2.0% (mol)	Density 0.85 (kg/Nm3)
Carbon dioxide	3.0% (mol)	
Nitrogen	0.7% (mol)	
Butanes	0.8% (mol)	

3.1.2 The state of Australian natural gas infrastructure

The natural gas reserves in Australia are more than three times its oil reserves. Australia's proven and probable natural gas reserves are 109,051 PJ, which is equal to about 91 years supply at current production levels.

Australia has several natural gas resources ranging from major basins such as the Carnarvon (in northwest Western Australia), Gippsland (in the Bass Strait off Victoria's south-east coast), and the Cooper/Eromanga Basins (on the borders of South Australia and Queensland)[31]. The North-West Shelf, account for 80 per cent of Australia's gas reserves [38].

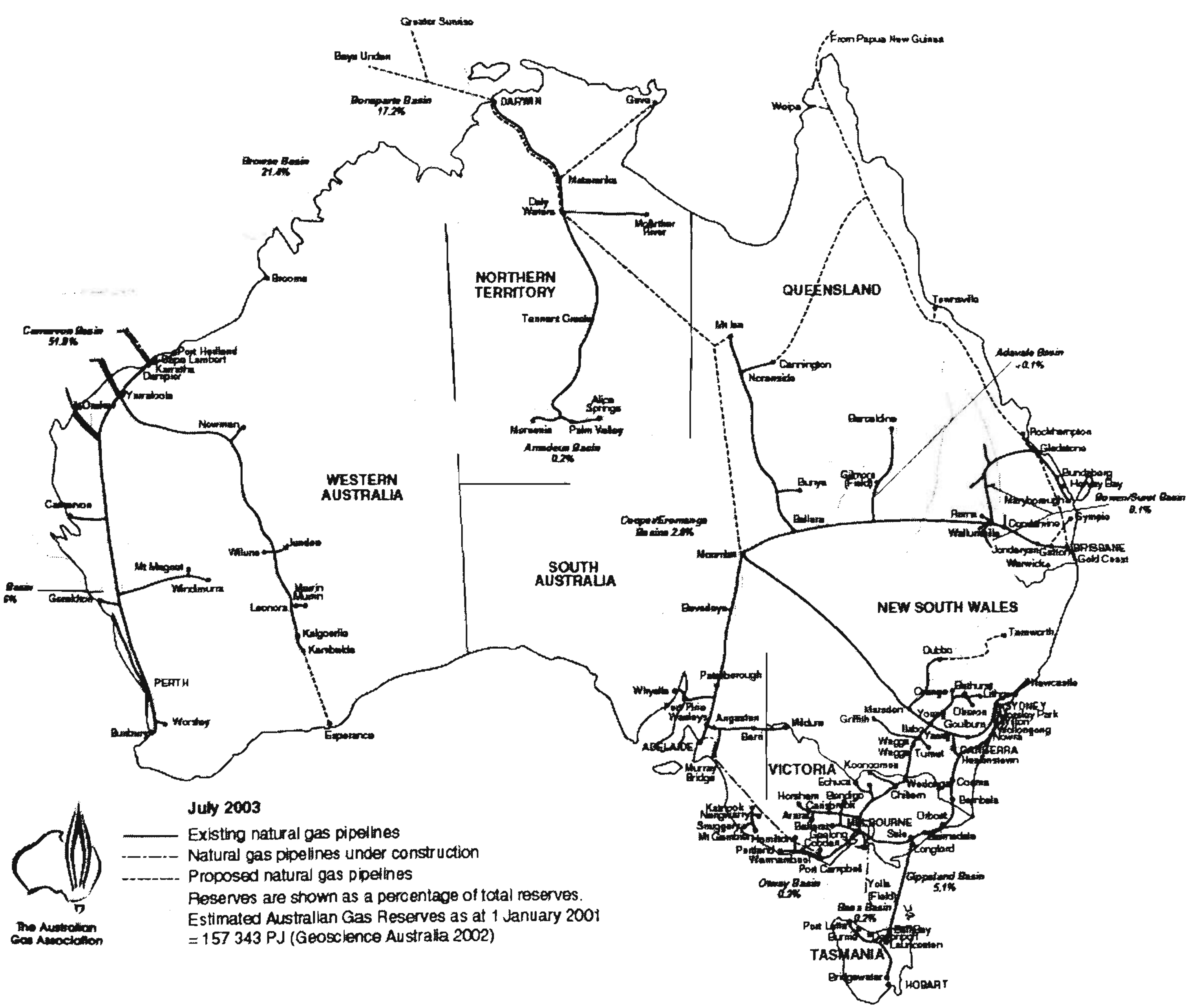


Figure 6: Natural gas production and distribution network in Australia [39]

Figure 6 shows the natural gas infrastructure in Australia. The majority of Victoria's natural gas is sourced from the Gippsland Basin and is produced at the Longford processing plant. A small but growing amount of gas is supplied from other gas fields in the Gippsland and Otway Basin and increasingly gas is being supplied interstate from Victoria. At projected consumption rates, Victorian natural gas reserves that are currently known are expected to meet demand for at least the next 15–30 years [27].

Australia's natural gas reserves are linked to major consumption sites by over 17,000 km of high-pressure transmission pipelines used solely for the transportation of natural gas. Most natural gas markets are supplied by a single pipeline, which carries gas from a single production centre [31]. Australian gas distribution network currently supplies 3.1 million domestic consumption sites (with approximately 6 million people), and 92 commercial and industrial customers through over 70,300 kilometres of local reticulation pipelines [31]. The natural gas distribution sector involves operating the lower pressure gas reticulation or pipeline network system, which takes the gas from the city gate stations to homes, offices and factories. The natural gas distribution network consists of over 75,000 km of gas reticulation pipeline [39]. Natural gas distribution system in Victoria includes over 8,300 km of natural gas mains and supplies over 400,000 consumers in metropolitan and regional areas [40].

Natural gas supplies for Victoria are obtained mainly from the Gippsland basin fields operated from private fields. Another onshore gas field is located in Portland that supplies the adjacent regional centres. Figure 7 give the elaborate network system of the Victorian natural gas distribution system.

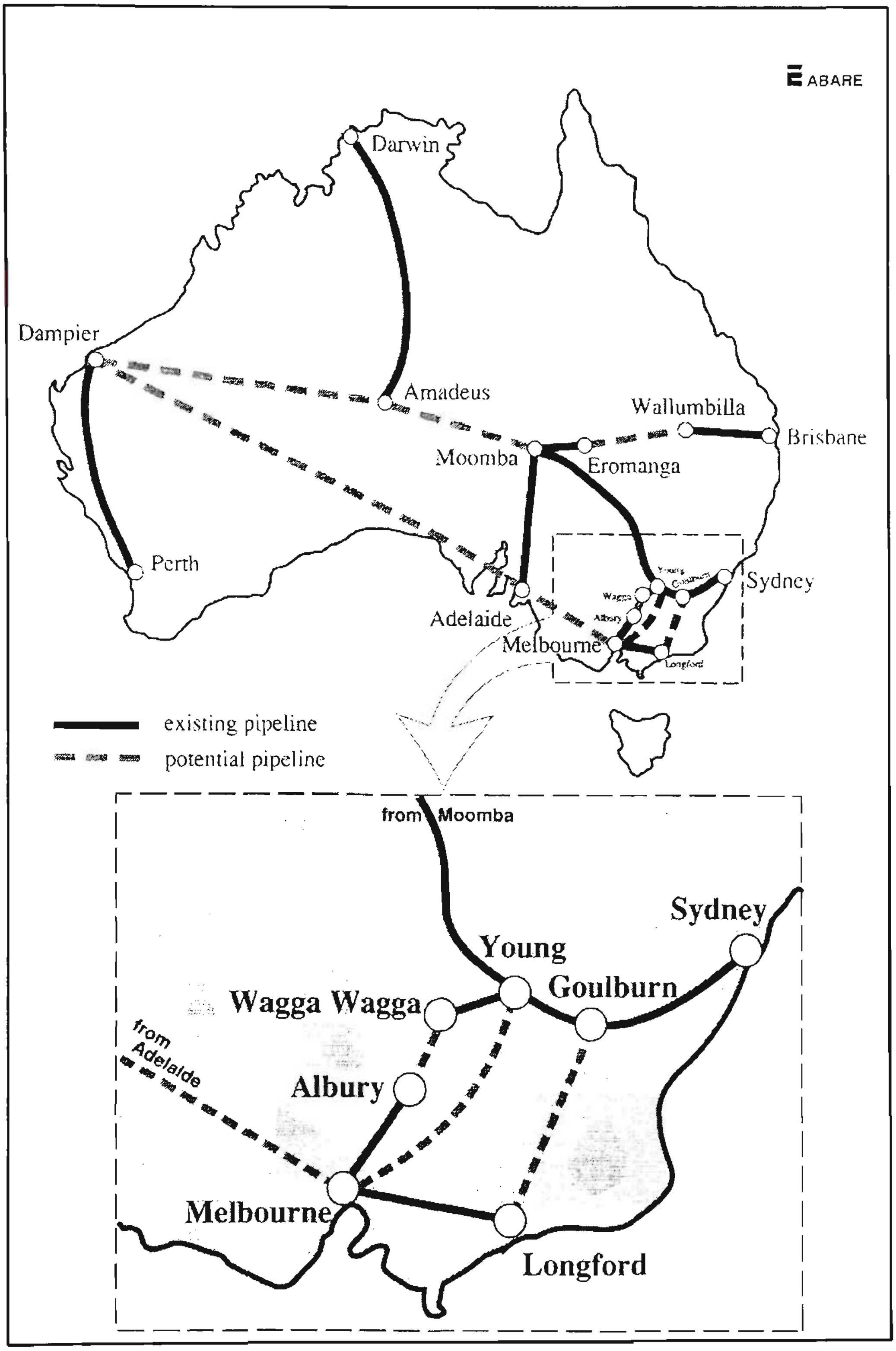


Figure 7: Natural gas distribution network in Victoria [26]

3.1.3 Natural gas consumption

In 2001, all the consumption utilities in Australia consumed around 996 PJ of natural gas. Where natural gas provided about 19.7 percent of the nations total primary energy needs.

Over the past 20 years, natural gas consumption has increased at an average of about 5.2 percent a year. This compares with an average growth rate for total energy consumption of 2.4 percent a year, and has resulted in natural gas's market share increasing from 12 percent in 1980-81 to 19.7 percent in 2001. More recently, natural gas consumption has been increasing at 3.9 percent per annum [39]. Factors contributing to this level of growth are:

- expansion of the pipeline network;
- gas's relatively low price compared to petroleum products and electricity;
- economic growth over the period;
- development of major gas-based industrial and mining projects;
- an expansion in the number of gas-fired power stations;
- environmental advantages which make natural gas an attractive fuel compared with other fossil fuels;
- Growing export demand for natural gas; and energy market reforms.

Table 7 gives the market segmentation of the Natural gas usage by the various consumer sectors in PJ.

Table 7: Natural gas consumption figure as per various sectors in Australia [41]

Market segment	NG consumption in PJ
Industrial	355
Commercial	46.5
Residential	112.8
Mining	133.1
Electricity generation	147.6
Transport	10.6
Other	12
Total	817.8

3.1.4 Natural gas transportation

The main consumption of natural gas (NG) is not currently close to the production sites; on the contrary it is very far away. This means that the transportation aspect of the natural gas markets is important economically and environmentally. The transport of natural gas is generally accomplished with pipelines from the production sites to the consumer. When the distances are long, natural gas can be condensed to liquefied natural gas, (LNG) to simplify transport. The density of LNG is 600 times higher than the density of NG. The process of changing NG to LNG then back again requires a lot of energy i.e. almost 15% of the calorific content of the natural gas itself [42].

In Australia, NG is transported through pipelines with different materials, sizes and performance. The recently proposed contract consists of building a double 14-inch (350mm) pipeline over 340 km and an 18-inch (450mm) pipeline over the remaining 340 km. The pipeline will transport gas from the Iona and Minerva gas fields in Victoria to three power stations in Adelaide, South Australia. The Eastern Gas Pipeline is 457mm (18") in diameter, manufactured to API 5L X70 specifications, with an operating pressure of 14.89MPa and a design gas delivery rate of 65 peta-joules per annum. The material used is a high quality steel alloy [43].

3.1.5 Natural gas distribution

To date, gas distribution has been characterised by demand centres linked to gas fields by single transmission pipelines. Gas reserves have generally been sold on a long term Take-or-Pay contract basis to the major distributor and in some cases directly to major industrial consumers in each State. Transmission pipelines transport natural gas from gas fields to specified points, called Gate Stations, on the outskirts of major gas consumption regions where gas enters local distribution networks. Transmission pipelines are generally single pipelines of large diameters operating at high pressure over long distances.

The second leg of gas infrastructure systems, distribution networks, carries gas from central stations to ultimate consumers. Distribution networks are generally characterised by smaller diameter pipes carrying gas at lower pressures than transmission pipelines through a web of pipelines. On the contrary, transmission pipelines and the distribution networks generally do not include compressors to induce the gas flow through them. Rather, once gas enters a network, gas moves towards consumers through several "pressure tiers" within the network by virtue of the gas pressure at the gate stations. Desired pressure levels within the networks are maintained through the means of pressure regulators located in between each pressure tier [44].

3.1.6 Natural gas storage

Natural gas is often stored prior to the distribution pipeline just to act as a sort of buffer at peak hours. With central storage the distribution companies can serve their customers with higher reliability. There are also significant advantages with local storage at peak hours when the natural gas demand increases the local storage and reduces the time that is needed for the delivery system to respond.

There are different kinds of storage, such as, depleted gas or oil fields, aquifers and salt formation. Natural gas can be stored in pressurized vessels which gives certain flexibility in transportation and availability. A problem with natural gas storage is that they are very space demanding and are given certain limitations. To cope with the large volumes involving natural gas, natural gas is stored as liquefied natural gas LNG in specially constructed insulated containers [45].

3.1.7 Natural gas safety

There is a risk for gas leakage when transporting natural gas in pipelines. Common reasons are outer mechanical influence, corrosion, material problems, welding mistakes and leakage in pipe connections. Gas leakage is common in low and medium pressure pipelines than in high pressure pipelines, which often depends on the pipeline material. As mentioned before, the high pressure pipelines are made of steel. The risk that arises when there is a gas leakage is the fire hazard, the loss of gas and environmental impacts. Amongst the environmental impacts are the disturbance of ecological systems and methane's green house effects. Natural gas is non toxic and is lighter than air; it rises upwards and is easily removed with normal ventilation system.

Revised gas safety standards have been set by the office of gas safety (OGS), Victoria. The standards set the requirements of consumer piping, fluing, ventilation and appliance installation of natural gas and liquefied petroleum gas. To ensure continuity and safety of supply and gas quality, the OGS is the responsible authority for the on-shore production and storage of gas. The OGS promotes end use safety regulations to large users, typically where supply is from pressurized transmission [46].

3.1.8 Natural gas and the environment

The high amounts of Hydrogen in natural gas compared to coal and oil results in a more environment friendly combustion with high amounts of water and lower amounts of carbon dioxide produced. There are some forces working (mainly from supporters of bio fuels) against the increasing usage of natural gas. The promoters of bio fuels say that by using natural gas, the market for much more environment friendly bio fuels decreases. Methane is 30 times stronger gas than carbon dioxide therefore its leakage through gas pipelines must be prevented.

In Victoria, proactive preventative maintenance is applied to all accessible installations. Scheduled maintenance is planned on a frequency which delivers effective protection against the adverse effects of equipment malfunction or breakdown. For inaccessible, buried pipelines, maintenance is largely by effective response to reported leaks. In addition, programs for corrosion protection, leakage surveys and mains and service renewals are also in place. While providing adequate system pressures to ensure reliability of supply, pressure is reduced to very low levels at the consumer's premises thereby reducing and controlling the volume of gas released and hence the potential consequences in the event of a gas escape [47].

3.1.9 Natural gas Economy:

It is quite difficult to mention a specific price for natural gas today. Large consumers have their own deal with the suppliers. The price to connect the distribution net and the natural gas price itself depends on where the customer is located, how much the customer consumes. Table 8 elaborates the standard prices for natural gas supply in the suburban Victoria.

Table 8: Suburban natural gas supply charges in Victoria [48]

Domestic General	**Peak Period**	**Off-Peak Period**
Supply Charge	$17.33	
Commodity Charge		
First 3200 MJ	0.8922 c/MJ	0.8922 c/MJ
Over 3200 MJ	1.0506 c/MJ	0.8250 c/MJ
Commercial / Industrial	**Peak Period**	**Off-Peak Period**
Supply Charge		
Meter / Regulator capacity up to 100m3/hr	$23.02	
Commodity Charge		
First 100000 MJ	1.0166 c/MJ	0.7966 c/MJ
Next 450000 MJ	0.9128 c/MJ	0.5616 c/MJ
Over 550000 MJ	0.51029 c/MJ	0.46695 c/MJ

Peak periods apply from 1 June to 30 September inclusive. Off-peak periods apply from 1 October to 31 May inclusive. Tariffs are per meter billing cycle [48]. Prices shown include the general service tax (GST). Figure 8 shows the cost distribution for a pipeline installation for an interconnection between the state of Eastern gas pipeline and the Australian Capital Territory.

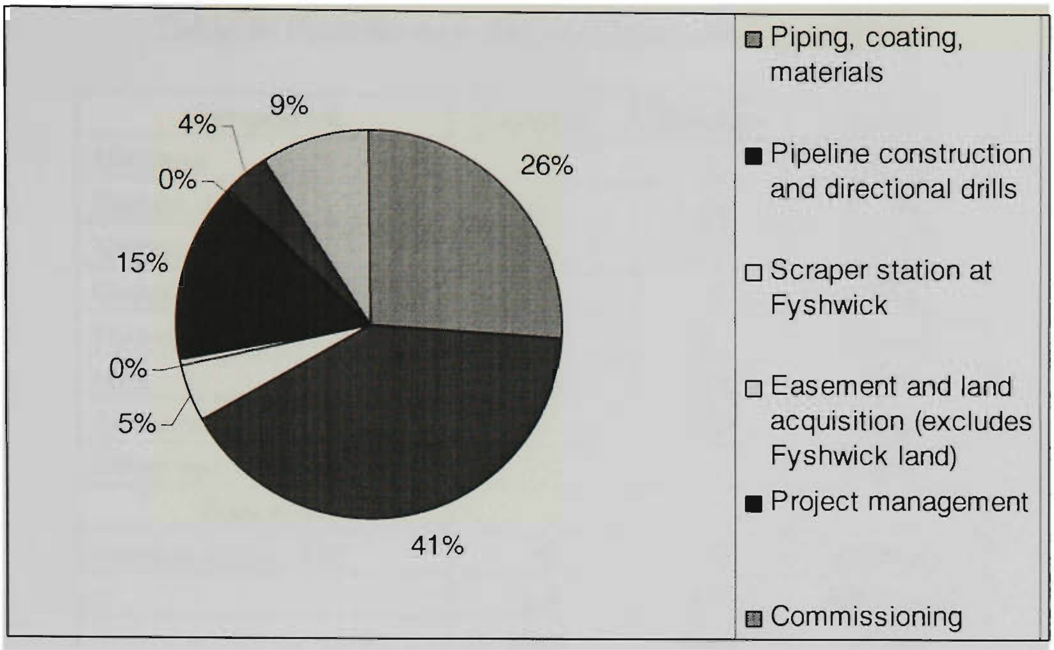


Figure 8: The cost distribution in a specific case where a 14.9 MPa pipeline with a length of 1600 meters installed as Australian capital territory (ACT) network extension to eastern gas pipeline (EGP) [49]

3.1.10 Natural gas in the future

Natural gas is thought of as a good alternative, as a "bridging" fuel between the traditional fuels used today and a future fuel. The assets of natural gas are sufficient to maintain power and heat production until environment friendly alternative is found.

3.2 Biogas

3.2.1 Biogas facts

Biogas is produced by microbiological conversion of organic material under anaerobic conditions. The production of biogas can occur naturally in places like swamps where the digestion of rotting takes place in an oxygen free environment.

The composition of the produced biogas varies depending on the raw material that is decomposed. Biogas mainly consists of methane (CH_4) and carbon dioxide. Hydrogen sulphide may exist in small amounts and the gas is saturated with water vapor. Upgraded biogas contains more than 96% methane and has a lower heating value of 9.6 kWh/cubic meters [29]. Table 9 shows the variation in composition of biogas obtained from landfills and sewage.

Table 9: Facts for two different types of biogases [50]

Component	Landfills	Sewage	Units
Methane	45	65	[vol %]
Carbon dioxide	40	35	[vol %]
Nitrogen	15	0.2	[vol %]
Oxygen	1	0	[vol %]
Hydrogen	0-3	0	[vol %]
H2S	100	500	PPM
Ammonia	5	100	PPM
Other hydrocarbons	0	0	[vol %]
Fuel data			
Heating value, LHV	16	23	MJ/Nm3
	4.4	6.5	kWh/Nm3
	12.3	20.2	MJ/kg
Density	1.2	0.85	kg/Nm3

3.2.2 State of Victorian infrastructure for biogas:

As on 2002, the total capacity of the biogas resource in whole of Australia was 122 MW. Almost 402 GWh of the electricity is generated from biogas which accounts for 2.2 % share of the electricity generated from renewables [51].

A Western Treatment Plant in a Victorian metropolitan suburb at Werribee discharges treated effluent to Port Phillip Bay. In 2000, a $124 million upgrade project was initiated to modify the plant to protect the long-term health of the Bay. This major eco-upgrade system now reduces nitrogen levels by enhancing the modern lagoon system with an activated sludge processes. This is increasing energy requirements at the plant. Simultaneously, the greenhouse gas emissions have been reduced by capturing increasing quantities of biogas collected from the covered lagoons. Power-generating facilities have been constructed under a partnership with AGL Ltd to produce electricity from biogas. Similarly under the eastern green energy project, biogas will be used to generate electricity at the plant. The project will produce 30GWh a year of green energy from biogas, reducing imported electricity needs and cutting greenhouse emissions by about 25,000 tonnes a year [52].

Berrybank Farm saves $435,000 per year from a $2 million investment in a Total Waste Management System. The System involves generating electricity from biogas, conserving and recycling water, and collecting waste for sale as fertiliser. The waste management system is a seven-stage process including automatic and continuous waste collection, grit removal, slurry thickening, primary digestion, secondary digestion, biogas purification and a cogeneration thermic plant. 1700 cubic metres of biogas, is able to run cogeneration electricity program with a daily output of 2,900 kW of electricity [7].

3.2.3 Biogas transportation

Currently the biogas resource is utilized to generate electricity. Such generating stations are located near the feedstock digesters that produce biogas. The transportation of the methane rich gas after treatment to the power generating station is done through the gas outlet pipe.

3.2.4 Biogas storage

By the basic principle, Biogas can be stored in the same way as the natural gas. The main method of storing biogas today is in pressurized containers where the storage type is categorized by the storage pressure (low, medium and high) [29].

To store the gas 'gasometer' or a compressor and some gas bottles are needed. The compressed form of the gas is not as compact as would be the liquid, but is marginally useable for local vehicular travel. The liquefied form would be ideal for vehicles, but to liquefy methane requires a considerable energy expenditure of about 20% to 33% of production, depending on operational scale, and needs expensive cryogenic equipment. The cost of the gas-filling and compressing equipment for compressed gas handling is not cheap, either, and requires a licence to operate in most Shires in Australia. The gasometer route is the one to take for most home use scenarios. It can be used for small stationary engines for various purposes such as pumping water, driving fixed machinery or generating electricity.

3.2.5 Biogas safety

An advantage with biogas is that majority of the different types of biogas have a lower density than air, which decreases the risk of dangerous gas accumulations when a leak occurs. Biogas contains water and sulphur which can cause corrosions, if not removed.

3.2.6 Environmental aspects of biogas

Due to the fact that biogas is a bio fuel, it gives no net contribution of carbon dioxide to the atmosphere which as the major driving factor for deriving considerable interest in this resource. Methane, a major constituent of biogas is also the major green house gas. When harnessing the biogas resource, preventive measures have to be taken in order to avoid gas leakage from the system. Some plants encounter problems with methane gas leakage into the surroundings. It is in the interest of the governing state to introduce and implement the code of safety rules to cope with the problem.

3.2.7 Economics of biogas infrastructure

The investments in the form of raw material costs and the production cost of biogas to a considerable extent in wastewater treatment plants is valued as zero. This is because the gas arises as a waste product of the treatment process. As the demand of the biogas increases, the production from new plants where organic waste is digested increases. Generally for these types of plants, the cost of raw material for the extracted biogas is strongly dependent on the cost of the waste product treatment and the fee for digestion wastes. In Australia, electricity generated from renewable energy such as biogas is worth a $40 /Gwh premium over electricity from non-renewable sources [53].

3.2.8 Applications of biogas

Some of the current applications where biogas is utilized are:

- Heat production,
- Power production and
- Fuel transportation

3.3 Hydrogen

3.3.1 Hydrogen facts

Hydrogen is the cleanest energy carrier fuel. Hydrogen is present in the atmosphere occurring in concentrations of 0.5 ppm by volume at lower altitudes [29]. Practically Hydrogen is not present in considerable amounts as a readily available natural resource. It can be extracted from the other readily available mineral resource such as natural gas. It is the lightest gas known with the density approximately 7 % of air density. Table 10 gives density and lower and higher heating values for hydrogen gas.

Table 10: Facts about Hydrogen [6]

LHV (g)	2.8	[kWh/Nm3]
HHV (g)	3.3	[kWh/Nm3]
LHV (liq.)	2300	[kWh/Nm3]
Density (g) 1 atm, 20°C	0.084	[kg/ Nm3]

Hydrogen stands for approximately 1 % of the world's energy conversion. Steam reforming of natural gas and partial oxidation of oil represent 76 % and 23 % of the world's Hydrogen production respectively. Approximately 1 % is produced through electrolysis of Water [29].

3.3.2 Hydrogen Production

Some of the different ways of producing Hydrogen today are:

- By-product in different chemical processes;
- Steam reforming of Heavy Hydro-carbons;
- Steam reforming of Natural gas;
- Gasification of coal;
- Electrolysis of water;
- Production from biomass.

The technology of reforming fuels into Hydrogen becomes more and more interesting today. There are several ways of extracting Hydrogen from different fuels. Some reforming processes are more developed than others. For example, the reforming of natural gas is fully developed and commercialized whilst the reforming of diesel, ethanol and other fuels are not fully developed but is still in research stages. There are three main processes used in reforming. They are, steam reforming, partial oxidation and auto thermal reforming.

A] Desulphurization

If fuel used for Hydrogen production contains sulphur it has to undergo a desulphurization processes before its introduction into reforming processes. This is due to the deactivation effect that sulphur has on the catalyst in the reformer and the fuel cell. The desulphurization unit has to be adapted to the level of sulphur concentration of the fuel.

B] Steam reforming

Hydrogen can be produced through steam reforming in the presence of catalyst, usually nickel. The catalyst decreases the necessary temperature and speeds up the reaction rates. For steam reforming the best fuels are those that contain short coal chains and therefore is easily vaporized. The fuel and water are vaporized in the reactor where the following reaction takes place [5].

$$C_nH_m + nH_2O \longrightarrow nCO + (n+m/2)H_2 \qquad \text{Eqn. B1}$$

The above reaction is endothermic and therefore requires energy from Hydrogen. In steam reforming, there is a risk of coking. The formation of coke decreases the amount of hydrogen produced. To avoid the formation of coke a high molar ratio between the water vapour and fuel is chosen. The production stream usually contains 5 to 20 % carbon monoxide, a large amount of Hydrogen and a low amount of different species. For the use in low temperature fuel as PEM, a low maximum concentration of carbon monoxide is required. A high concentration of carbon monoxide can cause catalyst deactivation. Other components like sulphur can also cause deactivation of the catalyst. When producing Hydrogen for a fuel cell system the purity is of utmost importance, which is why the choice of fuel and type of reforming are big issues in this area.

The advantage with steam reforming is that it has a high efficiency which gives high Hydrogen yield. There is also a possibility to use surplus heat produced in the processes. The disadvantage with the process is that the reaction rate is low and that a large reactor is needed. The large size of reactors is due to the heat exchangers. The system also has a long response time which in some cases is a very important parameter. For example in cases where the possibilities of storing hydrogen is low, and the importance that Hydrogen is delivered high, a low response time is needed.

C] Partial oxidation

For heavier hydrocarbons with long coal chains steam reforming is not a good alternative due to the fact that they are not completely vaporized. Partial oxidation is used for heavier hydrocarbons. The risk for coking is much lower with partial oxidation than it is for steam reforming, but of course it depends on the fuel used. Due to the low risk of coking heavier hydrocarbons like diesel and gasoline can be used. The partial oxidation process is exothermic. The process is based on extremely rich fuel combustion (low air/fuel ratios). The main reactions that occur when alcohol is used as a fuel [54]:

$C_xH_yO_z + (x\text{-}z/2)\ O_2 \longrightarrow y/2H_2 + XCO_2$ Eqn. C1

$C_xH_yO_z + (x/2\text{-}z/2)\ O_2 \longrightarrow y/2H_2 + XCO_2$ Eqn. C2

$C_xH_yO_z + (x+y/4\text{-}z/2)\ O_2 \longrightarrow y/2H_2 + XCO_2$ Eqn. C3

As mentioned earlier, the reactions that occur depends on the fuel used and cannot be generalized. Partial oxidation is performed at relatively high temperatures (800 to 1300°C) which brings the risk of methane formation. For most fuel cells methane presents a problem, therefore the production stream must be cleaned before it is used.

Partial oxidation can be performed either with or without catalyst. Advantages with the system containing catalyst are that the needed temperature and the consumption of oxygen are decreased. One drawback with the catalyst is that the fuel must be cleaned from sulphur due to the risk of catalyst deactivation. A commonly used catalyst is copper/zinc (Cu-Zn).

Advantage with partial oxidation is that the process is insensitive to contaminants and choice of fuel. The system has a low response time which is of big importance in mobile applications. The low response time is of big importance in mobile applications. The low response time of the system is partly due to the absence of heat exchange in the reactor. As the reactions are exothermic no external energy is needed.

Disadvantage of the process is that the Hydrogen yield is low. The fact that there is no water (containing Hydrogen) supplied to the reactor as in steam reforming lowers the Hydrogen yield. There are some risks of coking when heavier hydrocarbons are used.

D] Auto thermal reforming

Auto thermal reforming is the most difficult process to define, as it is not a single step but a combination of separate processes into one. Auto thermal reforming is in simple terms a combination of steam reforming and partial oxidation. The heat generated by partial oxidation is used to supply heat to steam reforming step [55].

The process is called auto thermal reforming duel to the fact that the reaction is balanced in regard to the heat ($\Delta H = 0$). A suitable temperature is 700°C and usual catalyst can be a blend of platinum and palladium.
The general reaction for auto thermal reforming is

$$C_nH_m + x(O_2 + 3.76\ N_2) + (2n-2x)H_20 \longrightarrow nCO_2 + (2n-2x + m/2)H_2 + 3.76xN_2$$
Eqn. D1

The process begins with the partial oxidation where only air and fuel are supplied to the reactor. Later water is supplied and the amount of supplied air is decreased which starts the steam reforming part of the process. The heat needed in the steam reforming is supplied from the partial oxidation step. The efficiency of auto thermal reforming is higher than the efficiency for partial oxidation but lower than for steam reforming [29].

E] Water gas shift reaction

One of the methods to lower the carbon monoxide concentration in the product stream is the water gas shift method. It uses chemical reaction called water-gas shift and it is constantly used in the chemical process industry. The water gas shift reaction is

$$CO + H_2O \longrightarrow CO_2 + H_2O \qquad \Delta H = -41\ kJ/mol$$ Eqn. E1

The reaction rate is relatively slow and therefore a large reactor is needed. The water gas shift reaction is performed at different temperature levels, high and low temperature. First the reaction is executed at high temperature of 350-450 °C and then at lower temperature of 180-270°C. After the two steps the carbon monoxide levels are approximately 0.5 to 1 vol %. To lower the concentration even further an additional cleaning step is needed, for example selective oxidation (preferential oxidation PROX) [29]. After the PROX step The CO levels should be less than 50 ppm to be compatible with a PEM fuel cell system [5].

3.3.3 State of Australian Hydrogen infrastructure

Currently the market for hydrogen production is in applications other than being an energy carrier. The transport sector is an exception to this where Hydrogen is harnessed as a primary fuel source. The West Australian government is investigating a $ 8.16 million to trial Hydrogen fuel cell buses in partnership with DaimlerChrysler, BP and Murdoch University in Perth. Table 11 gives the areas of implementation and the manufacturing cost of Hydrogen in Australia [18].

Table 11: Summary of common hydrogen production methods [20]

Production process	Summary	Current Usage	Approximate Manufactured Cost ($/GJ)	Used in Australia?
Steam-methane reforming	There are three steps involved in this process: steam reforming, water gas shift reaction and hydrogen purification.	Reagent in the petrochemical industry	8	Yes
Partial oxidation of hydrocarbons	The hydrocarbon feedstock is oxidized to produce CO2 and hydrogen.	Chemical processes such as oil refining	18-25	Yes
Gasification of Coal, Biomass or Wastes	The hydrocarbon feedstock is gasified at high temperature to produce a syn-gas, which is then processed and purified to obtain hydrogen.	Chemical processes such as ammonia production	10-11	Yes
Water electrolysis	Electricity is passed through an aqueous electrolyte, breaking down water into its constituents.	Insulator and cooling gas in high power alternators	29-42	Yes, minor scale (eg. Power industry point of use)

At present there is no actual market for liquid Hydrogen though the idea of producing such an infrastructure for motive applications is in its rudimentary stages. The entry points for Hydrogen into Australian markets can be represented to form a cluster which indicates the export target goals as well as the local markets. One of such markets is the decentralized market where the power production units in the form of micro-turbines or fuel cells running on Natural gas Hydrogen. The sizes of such power generating units in the de-centralized markets is as high as 40-200 kW/hr [56].

The transport sector, particularly the road transport is the largest consumer after the manufacturing sector. Australian transport fuel demand shows that the total fuel consumption for the Australian vehicle fleet in 2000 was an estimated 25 billion litres. Passenger vehicle consumed a total of 16 billion lifters of fuel of which 88% is petrol [20].

An array of motor vehicle companies is developing Hydrogen internal combustion engine vehicles. As mentioned earlier, the Perth Hydrogen fuel cell bus trial is a step in this direction.

3.3.4 Hydrogen transportation

Hydrogen can be transmitted and stored as either a gas or cryogenic liquid. Hydrogen is non-corrosive and may be contained at ambient temperatures by most common metals used in installations designed to have sufficient strength for working pressures involved. Equipment and piping to contain Hydrogen should be selected with a consideration of hydrogen embrittlement. This is particularly important at elevated temperatures (232° C) and pressures. Embrittlement is caused by the absorption and diffusion of the small Hydrogen molecules through the metal which makes the steel more susceptible to stress fractures. Hydrogen can be transported by pipelines or pressurized containers. The most economical way of transporting Hydrogen is by pipeline. Stainless steel piping is preferred when distributing Hydrogen. However distribution in pressurized vehicles can also be considered. For distances over 500 kM, the transmission of hydrogen can be significantly cheaper than the transmission of electricity through wires. The possibility of storing hydrogen creates a solution to the problem of storing electricity. Hydrogen flows very easily and at equal pressure ratios and pipe diameters. The flow of Hydrogen is 2.68 times than that of methane.

This fact means that the lower heating value of Hydrogen per volume is almost compensated due to the fast flow [29]. To get the same capacity as natural gas pipeline, the diameter of the hydrogen pipeline has to be approximately 30 % larger if the other parameters are the same [29]. Metals used for liquid hydrogen must have properties to withstand very low operating temperatures. In America for example, several precautions are made to ensure the safety when handling liquid Hydrogen during transfer are [57],

- Hydrogen tankers to be adequately grounded during loading and unloading operations;

- Only the operating personnel thoroughly acquainted with liquid Hydrogen operating procedures, equipment and its properties are permitted to perform transfer operations;

- Transfer operation to be discontinued during thunderstorms;

- Transfer hoses in liquid Hydrogen service to be purged with Helium or gaseous hydrogen before usage.

3.3.5 Hydrogen storage

During the storage, precautions have to be taken to prevent leakage which can be caused due the small molecular size of Hydrogen.

The containers used to store liquid Hydrogen are double walled to allow use of vacuum insulation in addition to insulation to prevent heat transfer from conduction, convection and irradiative sources. The storage containers of compressed Hydrogen are similar in construction to those used to store compressed natural gas. These containers can be made from steel, aluminium or composite materials. The choice of materials is also an important issue due to the risk of Hydrogen embrittlement. Hydrogen has a low energy density that makes storing a problem. Compared to all other fuels, Hydrogen has the lowest energy storage density. For example, Hydrogen has to be compressed to 3500 bar to attain the same energy density as heating oil [6]. To store large amount of Hydrogen in normal size containers, very high pressures are needed which in turn affects the material requirements. Even when liquid Hydrogen has only 20 % of the energy contained in the same volume of gasoline [58].

Hydrogen can also be stored in form of hydrogen rich compounds such as methanol, ammoniac etc. Sodium boro-hydrite is another chemical rich in Hydrogen like methanol. It is a density close to that of petrol and can be easily transported. Hydrogen is produced on demand when the solution is passed through a catalyst releasing pure Hydrogen. The chemical has got a considerable potential however the costs have to be reduced [56].

The most common ways of storing Hydrogen are,

- Pressurized cylinders;
- Above ground storage tanks;
- Caverns, aquifers and natural gas and oil fields;
- Pipeline networks.

3.3.6 Safety measures with Hydrogen

The flammable limits of Hydrogen in dry air at atmospheric pressure are 4 to 75 % hydrogen by volume. The energy needed to ignite Hydrogen is very low, 0.02 milli-joules compared to methane which is 0.29 milli-joules. When handling Hydrogen, there must be a good ventilation system in case of a leakage. Due to the lightness of Hydrogen, it does not accumulate near the ground at a leakage site; instead it rises up in the atmosphere with the speed of 20 meters/sec. outside the sealed containers, it is almost impossible to get a detonation with a flame or a spark when a small leakage occurs. Hydrogen is non-toxic and the radiation of heat is lower for the Hydrogen flame than the other fuels. Liquid Hydrogen that leaks can cause cooling damages on human tissue, metal and rubber [20].

3.3.7 Environmental impacts of Hydrogen usage

When Hydrogen is combusted in internal combustion engines, water vapour is the major emission, though some oxides of Nitrogen may be formed if combustion temperatures are high enough. When using neat Hydrogen in fuel cells, water is the only emission. Analysis has been conducted as to how the water vapour emissions from the Hydrogen combustion affect the environment. The present stand-point is that the water vapour contributes negligibly to green house effect.

Table 12 highlights the estimated greenhouse emissions associated with selected Hydrogen production processes.

Table 12: Estimated greenhouse emissions associated with selected Hydrogen production processes [20]

Production process and the cost of production	Emissions (kg CO_2/kg of Hydrogen)
Electrolysis using renewable power (tidal, wind, PV, etc.) ($42/GJ)	Zero
Electrolysis using conventional electricity (coal fired, plant efficiency 40 %) ($35/GJ)	37
Electrolysis using conventional electricity (gas fired, plant efficiency 55 %) ($29/GJ)	15
Steam reforming of natural gas (without sequestration) ($8/GJ)	5.5-7
Coal gasification (without sequestration) ($ 11/GJ)	15-16
Biomass gasification ($10/GJ)	zero

3.3.8 Hydrogen economy

The price of the Hydrogen as fuel depends significantly on the way it is produced. This can be proved by the fact that Hydrogen produced through solar electrolysis of water is ten times the cost of producing the same amount through steam reformation. The data for four different approximations of Hydrogen pipeline cost is shown in Table 13.

<u>Case 1:</u> In 1973, the cost was calculated for a pipeline between Gibraltar-Karlsruhe stretch was divided into 3 parts with pressure and dimensions [6].

<u>Case 2:</u> In a study done in 1993 an estimated pipeline cost for a pipeline from Algeria was approximated (including 300 kM under sea) [29]

<u>Case 3:</u> The Hydrogen pipeline cost mentioned in the study done in 1999 by Joan Ogden [7]

Case 4: The pipeline will transport Hydrogen from the Dow chemicals Canada Inc. facility [59]

Table 13: The pipeline cost and facts for three different cases

Facts	Case 1	Case 2	Case 3	Case 4	Units
Type of course	-	Difficult	-	-	-
Length	2150000	-		8700	M
Working pressure	26/102	100	14/69	-	Bar
Diameter	1100	1700	76	762	Mm
Fuel capacity	10 E 10	7.10 E 10	200 10 E 6	-	Nm3/Year
Total cost	-	-	-	6 10 E 6	$
Cost per meter	830	3690	1200	775	$/m
O & M cost	-	1.5 % capital cost	-	-	$

According to [4], the cost of pipeline delivery in Los Angeles is expressed by the following expression:

Price of pipeline in $/GJ) = 1.2 * Distance (KM)/Flow rate.

The cost of pipeline delivery depends on the flow rate and the length of the pipeline. Higher the flow rate, the shorter the pipeline, lower the cost [7].

3.3.9 Applications of Hydrogen

Some of the applications where Hydrogen is used as a raw material or as a fuel are as follows [57]:

- Dyes;
- Catalysts;
- Flavours and fragrances;
- Pesticides;
- Halogen organics;
- Plastic and synthetic fibres;
- Petroleum;
- Metal production;
- Welding and cutting;
- Heat treatment of different materials.

3.3.10 Future of Hydrogen Economy

In the imminent future, fossil fuels will stay the primary source of the energy carrier in form of Hydrogen. If the operating price of the electrolysis process to produce Hydrogen reduces, water will eventually replace fossil fuels as the raw material. Such a breakthrough is expected to occur in the next few decades. It is expected to take almost 50 years from now to make a giant transition from the fossil fuel economy to the Hydrogen based economy. At the current moment, the Hydrogen cannot compete with the fossil fuel lobbies. However various upcoming non-conventional areas of producing Hydrogen through the biological processes are being considered for commercialization.

3.4 Methanol

3.4.1 Methanol facts

Methanol, also abbreviated as methyl alcohol has got the most basic structure of Hydrogen to carbon. Natural gas is the primary raw material in the production of methanol. Other sources from which it can be derived are coal and biomass residue. If Methanol is to be considered as an alternative for fossil fuel, the raw material used for production has to be biomass. The problem with biomass is that very large plants are required for the production to be economically viable. The Methanol process begins with a step where the raw material is converted to synthetic gas. Synthetic gas consists of Carbon monoxide and Hydrogen. Methanol is then produced from synthesis gas over a catalyst at increased temperature and pressure. Often the synthesis gas must be cleaned from impurities before reaching the catalyst. Methanol has a boiling point of 65 °C. Table 14 indicates the values of the energy content of methanol fuel.

Table 14: Methanol facts [60]

LHV	4.37	MWh/Nm3
HHV	4.98	MWh/Nm3
Density	790	kg/Nm3

3.4.2 Australian methanol infrastructure

World demand for methanol is forecast to increase over the next several years. The emerging fuel cell technologies offer the largest future market for Methanol. The majority of fuel cell designs require methanol as their fuel input, particularly in commercial and domestic vehicles [61].

The "Tassie-shoal" Methanol project aims to construct two separate Methanol plants each on a concrete gravity structure. Each plant will have a 5000 tonne per day Methanol production capacity. The first plant could be commissioned and operational by 2009 [62].

It is planned that another Methanol plant, would be installed adjacent to the first about four years later raising the total Methanol production to 10,000 tonnes each day or 3.45 million tonnes per annum. The Methanol will be exported via tankers to customers in Southeast Asia and North America [61]. Similar encouraging signs for the development of a Methanol plant in west Australia are under consideration.

Melbourne methanol plant is capable of producing 60,000 ton of methanol each year. This represents approximately 70% of the nation's Methanol requirements and significantly reduces the country's dependence on overseas imports. The chemical industry accounts for approximately 80% of the country's Methanol consumption, with this being used in the manufacture of formaldehyde, which in turn is used to produce urea and melamine formaldehyde adhesive resins [63].

3.4.3 Methanol transportation

Methanol is mainly transported by truck and can be transported in pipelines. Methanol is a liquid at room temperature and normal pressure, which simplifies transport. Selection of appropriate material is imperative during methanol transportation. Methanol is corrosive to metals and can inflict damages to the material. Methanol is less hygroscopic (absorbs water from the surrounding air) than ethanol but still safety measures have to be taken to ensure that no penetration of water occurs. The volume of methanol that is needed to satisfy certain energy demand becomes 1.3 times higher than the volume of Ethanol. Certain precautions have to be taken when handling Methanol and a permit is required. Methanol is a good Hydrogen carrier due to its low volume and the simple process of cleaving methanol to Hydrogen [62].

3.4.4 Methanol storage:

Methanol can be stored in tanks above or underground. Acceptable tank materials for containing methanol include carbon steel, fibreglass, and stainless steel. Due to the cost, stainless steel tanks are rare. Carbon steel tanks used underground must be protected against corrosion, usually done with a fibreglass coating [64]. Methanol is a toxic chemical and can cause blindness. Methanol almost burns with an invisible flame and is very flammable liquid. Methanol is an odourless chemical which results in difficulties of detecting leakages. To cope with this, additives are added to give the liquid a recognizable odour [62].

3.4.5 Environmental impacts of using Methanol as a fuel:

Methanol evaporates when exposed to air and dissolves completely when mixed with water. If released to the air, Methanol breaks down to other chemicals and remains as a vapour for approximately 18 days. It does not bind well to soil and so can enter groundwater. On an environmental spectrum of 0 to 3 Methanol registers 1.2. A score of 3 represents a very high hazard to the environment and 0 a negligible hazard. Factors that are taken into account to obtain this ranking include the extent of the material's toxic or poisonous nature and/or its lack of toxicity, and the measure of its ability to remain active in the environment and whether it accumulates in living organisms. A substance that scores highly as an environmental hazard is oxides of Nitrogen at 3.0 and one of the lower scores is Carbon monoxide at 0.8 [63]. If a spill occurs, it is very hard to decontaminate the area due to its high solubility with water.

3.4.6 Methanol economy

The price of Methanol is approximately 0.08 $/ kWh and in 2010, the US department of energy predicts a price of 0.04 $/kWh in USA. The production cost for ethanol in Australia is up to 70 cents/litre [65].

At ambient pressure and temperature, 52 cubic metres of Methanol contains approximately 227 MWh (LHV), which gives a load of nearly 227 000 kWh (LHV)/truck.

Examples of what storage might cost are [64]:

A] Underground 10 000 gallons = US $ 62,407

B] Above ground = US $ 54,600

where 10,000 gallons = 37,854 litres and,
$ = 1.28 AUD (05)

3.4.7 Methanol applications

Methanol is used as,

- Fuel;
- Solvent;
- Raw material for chemicals.

3.4.8 Methanol future

Today in Australia methanol and ethanol are considered as the future fuels. However the methanol infrastructure is mainly targeted at the transportation sector.

3.5 Ethanol

3.5.1 Ethanol facts

Ethanol is one of mankind's oldest chemicals, which has been produced for thousands of years. It is produced bio-chemically from certain sugar types, starch or even cellulose. The easiest way of producing Ethanol is by fermenting sugar and then distilling the ethanol to achieve a high concentration. The distilling process consumes rather much energy. The most common raw material for Ethanol is sugar canes, sugar beets, corn and grain, which is widely used around the world. Ethanol can also be produced from starch rich raw materials as potatoes and from ethylene (raw oil). The Ethanol produced mainly consists of Ethanol (CH_3CH_2OH) and 5 % water. It has a boiling point of 78 °C. There are small amounts of methanol and aldehyde's. There is a lot of research going on about producing Ethanol from cellulose around the world. Major efforts have been put in to develop new efficient production techniques.

Ethanol has a wide raw material potential as in the following [66]:

- Wood: Cutting residuals, Sawdust, Clearing/ Thinning.

- Cultivation: Straw, Switch grass, Energy wood, Corn, wheat.
- Recirculation: Industrial waste, household garbage, Waste fiber.

3.5.2 State of Australian Ethanol Infrastructure

Ethanol is produced in Australia by the fermentation of molasses and wheat by-products. Some 90% of Ethanol is used as an additive for gasoline.

Bio-fuels such as Ethanol are produced from renewable biomass feedstock and represent a potential inexhaustible supply of future transport fuel for Australia in conventional vehicles and hybrid vehicles using fuel cells. The market penetration of Ethanol blend fuel in the Australian transport market is small, and has been achieved against the unrelenting opposition of the major foreign-owned oil companies that dominate the Australian fuels market. Of the 60 million litres of Ethanol produced 40 million litres is sold into transport fuel market for blending with petrol and the remaining 20 million sold to the chemical and pharmaceutical markets [67].

3.5.3 Ethanol transportation

In Australia today, Ethanol is mainly transported through trucks. Ethanol is hygroscopic which means that it absorbs water from the surrounding air. The penetration of water must therefore be stopped when transporting ethanol. As Ethanol is a liquid at normal temperatures and pressures, it is easy to transport.

3.5.4 Ethanol storage

Ethanol can be stored as gasoline, in metal containers. As said earlier the vessels have to be air tight to keep the high concentrations of Ethanol.

3.5.5 Ethanol safety

Ethanol is not classified as a toxic chemical but due to possibilities of misuse it has to be denaturized. The safety measures handling Ethanol is less extensive than it is for gasoline or methanol. Ethanol does not burn with a visible flame.

3.5.6 Ethanol and the environment

When Ethanol is produced from biomass and not from fossil sources, it is said to have no net contribution to the global discharge of carbon dioxide. Life cycle analysis says that Ethanol has much less impact on the greenhouse effect than gasoline and oil does. Discharges and leakages of Ethanol to the water and ground is easily decomposed and not a large environmental problem. Ethanol is decomposed naturally to water and carbon dioxide.

3.5.7 Ethanol economy

Ethanol costs more to produce then petrol. According to a report from the Bureau of Transport Economics production costs of ethanol from corn, cereal or sugar are mainly in the range 40 to 70 cents per litre (58 cents to $1.02 per litre of gasoline equivalent) [68].

A gallon of Ethanol contains less energy than a gallon of gasoline. The production cost of ethanol must be multiplied by a factor of 1.5 to make an energy-cost comparison with gasoline. This means that if ethanol costs $1.10 per gallon to produce, then the effective cost per gallon to equal the energy contained in a gallon of gasoline is $1.65 [69]. In contrast, the current wholesale price of gasoline is about 90 cents per gallon. Table 15 gives a typical cost breakdown of an Australian fuel Ethanol plant.

Table 15: A typical cost breakdown for a Ethanol production plant [69]

	Percentage of Total Cash Operating Cost
Grain Feedstock	72%
Utilities	17%
Consumables	4%
Labour	4%
Maintenance	1%
Administration & Expenses	2%

Distribution costs for ethanol are also higher than petrol because the lower energy content of Ethanol requires a large increase in the amount of fuel transported and stored for a given energy supply - one litre of ethanol has an energy content of 23 megajoules, petrol has 34 megajoules [70].

3.5.8 Ethanol applications

Some ethanol applications are,

- Transportation sector;
- Raw material for chemicals;
- A future possible application in combined heat and power production.

3.5.9 Ethanol in the future:

USA and other countries like Brazil see ethanol as a future fuel. The use of ethanol is mainly to replace gasoline and diesel in the transportation sector. The big point for USA is to be self-sufficient of fuel and not dependent on the other OPEC countries.

3.6 Liquefied petroleum gas (LPG)

3.6.1 LPG facts

This is a brief description of LPG at its stand-point today. LPG is a petroleum product that consists of propane, butane and propylene. The main component is propane (about 90%) [58]. At ambient temperature and pressure, LPG is gaseous, but with slightly increased pressure, it liquefies. This property makes it easy to store in pressurized containers. LPG's liquid density at 20° C is about 500 kg/m3. Its density as a gas is 1.5 to 2 times higher than the density of air, which in case of a leak, means that it sinks to the ground. It has a lower heating value (LHV) of 46 MJ/kg which is equal to approximately 6.4 MWh/m3 [71].

The environmental properties of LPG are very common to natural gas. LPG is free of heavy metals and has a very low content of sulfur. For certain industrial processes, a very high demand of purity and a careful monitoring of the temperature are needed. In such case LPG has qualitative properties compared to many other fuels.

3.6.2 LPG production

Two different ways of producing LPG are:

- Separation of heavy hydrocarbons in Natural gas and
- Distillation of Gasoline.

In a simple refining of crude oil, 35 kg LPG per ton oil can be extracted [29]. When refining at high exchange of gasoline the amount of LPG extracted can be as much as 50 to 100 kg per ton crude oil.

3.6.3 Applications of LPG

Different applications where LPG is widely used are,

- Engine fuel;
- Mobile Kitchens;
- Mobile homes and boats;
- Heating of buildings;
- Soldering;
- Industry;
- Reserve power;
- Agriculture.

3.6.4 Production of LPG

During 2000, Australia produced 3.3 million tonnes of LPG. Approximately 78% of Australia's LPG was sourced directly from underground reservoirs, generally as an associated product of crude oil and natural gas production. This is known as naturally occurring LPG. The remaining 22% is extracted from crude oil during the refining process at eight refineries located near Australia's major mainland cities [72]. LPG is produced when crude oil is heated and when reformers produce petrol. More LPG is produced by refinery reformers as the octane requirement of petrol produced increases. Australia's naturally occurring LPG is sourced predominantly from Bass Strait (offshore Victoria), the North West Shelf (offshore Western Australia) and the Cooper-Eromanga Basin (in central Australia) [72].

3.6.5 Transportation of LPG

LPG is transported through a pipeline on a large scale. It is delivered in compressed form in cylinders for domestic usage. The flammable limits are lower than 2.1 vol-percent and higher than 9.5 vol-percent. The burning flame of propane is visible in all conditions [58].

3.7 Diesel:

Diesel oil exists in various grades and is most abundant and easily available fuel. Diesel oil has high energy content per unit volume. Diesel has a lower heating value of 230 kJ/mol and a boiling point of 230°C [73]. The density of diesel is 880 kg/Nm3[74]. Diesel is a fossil fuel and is hard and complicated to reform into hydrogen. If Diesel is to be considered as a fuel for fuel cells it will probably be for the transportation sector and not for stationary fuel cell systems. Since fuel cells in general are sensitive to sulfur contamination of the fuel, diesel oil has to be de-sulfurized before use. Therefore no further information is gathered about diesel in this report.

4. THEORY AND PREREQUISITES FOR ANALYSIS

The economic analysis constitutes the annual cost computation of an alternative energy system. The system is assumed to be designed for a hypothetical residential installation powered by a fuel cell system in a metropolitan suburb of Australia. For the assumption of certain cost parameters, an actual photovoltaic grid interactive residence located in a Melbourne suburb is considered as a case study [75]. Several computational formulae derived from various literatures and textbooks have been applied to carry out the cost estimations. In the analysis, three different system architectures namely, central, split and local are compared with each other. For central and split architectures, combinations of more than one individual and identical residential installation have been considered. The energy system is essentially a cogeneration unit supplying heat and power demands of a residential settlement. Several vital aspects are to be considered while designing the co-generation unit. The crucial one of them would be the estimation of the heat and power loads at the consumer end. Two demand strategies have been implemented in the analysis; one where all the heat loads of the building is supplied by the fuel cell system and the other where it is possible to supply a specified part of power demand with the fuel cell system. The fuel cell system is assumed to be Polymer Electrolyte Fuel Cell PEFC.

A typical PEFC system is shown in Figure 9

Figure 9: Plug and power's 7 kW residential PEM fuel cell power plant [76]

Living circumstances in Australia are simulated by assuming a building size of 150 square meters. The total heat and power loads for the buildings are assumed to be 5.33 MWh /year and 1.9 MWh /year respectively [75].

As mentioned earlier, the demand figures are derived by monitoring the annual hourly demand profile of a hybrid solar grid interactive house in the Melbourne metropolitan area. The sizing of the fuel cell system is assumed to be the same as the major power source (Photovoltaic array) considered in the actual case study done at the residential location having a grid interactive feature located in Victorian metropolis. The power demand varies during the day whereas the heat demand is strongly dependent on the season.

4.1 The Total Heat Supply Strategy

The fuel cell system is assumed to be large enough to completely supply the building with its heat demand. To supply the buildings heat demand, the fuel cell system is estimated to have a maximum heat output of 5 kW_{th} . A 35% power efficiency and a total fuel efficiency of 100% for the fuel cell system means that a 2.69 kW_{el} system is required.

When total fuel cell efficiency is 100% or when there are heat losses due to heat distribution, the system size increases. The heat variation and the peaks above 5 kW_{th} are assumed to be covered by heat storage. An approximation from the hourly demand estimation done at the case study site gives power bought from power grid to be 304 kWh/year (16% of the total power demand).

4.2 The Partial Heat Supply Strategy

The photovoltaic grid interactive house has been designed to supply the base load demand that never exceeds 2 kWel and the peaks are supplied by the grid. Therefore requirements for the fuel cell system are that it must be able to supply 2 kWel which is the minimum continuous power demand to the building. The reason for the second alternative could, for example, unusually high requirement for continuous power supply. With a 2 kWel fuel cell system, a larger part of power would be bought from the power grid and a part of heat demand supplied by additional heating.

An approximation from the hourly demand estimation done at the case study site gives additional heat demand of 1,066 kWh/year and power bought from the grid to be 513 MWh/year (27% of the total power demand).

4.3 Aspects of the two approaches of demand supply

The results depend on the power efficiency of the fuel cell system. The calculated values are assumed as valid approximations for all efficiencies. The choice of demand approach depends on the investor's priority and external factors such as fuel price, power price and possibilities of connections to district heating etc [77].

4.4 System architectures

As mentioned earlier, three system architectures have been considered in the analysis:

1. **Central configuration:** In this architecture, all the heat and power are produced in a central site by a PEFC system.

2. **Split configuration:** The fuel is reformed to Hydrogen in a central reforming site. The Hydrogen is then distributed to each building in Hydrogen pipes where the heat and power production takes place with the help of a PEFC.

3. **Local configuration:** The fuel is transported directly to each building where it is reformed and transformed to Power and heat by a PEFC system.

In the case where additional heat is needed, a burner is used which is localized nearby the fuel cell. In the central and local architectures, the chosen fuel is used in the burner. In the split case, the chosen fuel is not transported to the building, thus hydrogen must be used in the burner. In the study, the role of Power Company is taken; network fee and GST are excluded in the calculations. The customer whose demand of power and heat is fulfilled pays tax, network fees and GST.

Several technical and economic assumptions have been made that applies for all three architectures:

- There are no energy losses in the fuel distribution pipeline network.

- There is no energy loss in hydrogen distribution pipeline network.

- Heat loss in the heating pipeline is 0.015 kW per meter of heating pipeline.
- With the use of heat storage (water tank), the variation of heat demand over day and night can be covered.
- The building utilizes the heat losses.
- The fuel cell and reformer has a sufficient response time to cover sudden changes in heat demand.
- A burner covers the need for additional heat in the second demand approach (efficiency of 94%)
- The PEFC can be shut down and started again in reasonable time limit, which is a prerequisite for operation under the warmer periods of the year.
- An electric efficiency of the fuel cell systems of 35% and turn down ratio of six are assumed.
- The air-conditioning load is assumed to be fulfilled by the electric power (tri-generation feature of the fuel cells can be considered in future studies).
- An interest rate of 8% is assumed for the standard case. (The standard case is where all the parameters have a predefined values)
- A depreciation time of 20 years is assumed for the production system.
- The fuel cell system lifetime is set to 20 years. A lifetime target of 40,000 hours for the fuel stacks is accepted which is approximately 4-5 years. To get a theoretical lifetime of 20 years a high operation and maintenance (O & M) cost is assumed. The O & M cost in $/ year is assumed to be the yearly capital cost for a fuel cell with a lifetime of 5 years and with interest rate assumed in the calculations. The fuel cell O&M cost per year corresponds to the investment of additional fuel cells under a 20 year period. A depreciation time of 40 years is assumed for the distribution net for heating, hydrogen and fuel pipelines.

- The O & M cost for the distribution system is assumed negligible.

- The heat exchanging system in the buildings is the same for each of the three configurations and the reference system, the cost is therefore not included in the calculations. Similarly, the cost for the hot water tank is not included in the calculations.

- Unforeseen expenses are 10 % of the total system cost.

In the central and split architectures, the distance from the fuel source to the building is the sum of the distance from the central site and the distance from the central site to the building. The three different architectures are then compared with the benchmark case.

4.4.1 Central configuration

The fuel is transported to a central production unit through a pipeline. The central production unit consists of a natural gas reformer and PEFC stacks as shown in Figure10. The power and heat are then supplied to the individual residential blocks R1, R2, R3 and R4 through a power grid and a pipeline network.

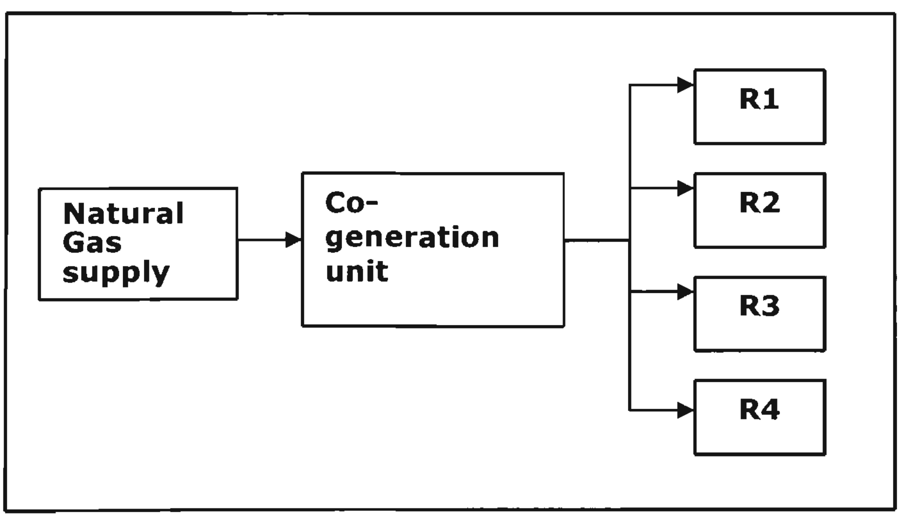


Figure 10: Central co-generation system layout

Technical assumptions

- There are heat losses in the main heat pipe to the buildings. Heat losses in the pipes between the main pipe and the buildings are negligible due to short distances.

- Sizes of system components are calculated from the sum of all demands for all the buildings.

- The power loss due to distribution is negligible.

- There are heat losses from the fuel cell due to its position at a distance from the buildings.

Economic assumptions

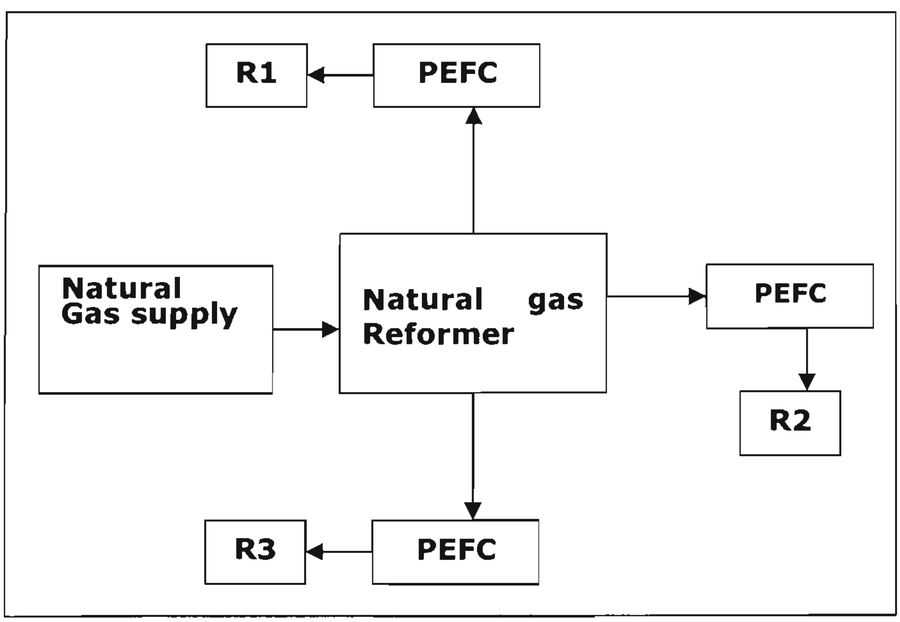
- The cost for buildings and help equipment is 10% of the system cost.

- The cost for land improvement is 10% of the system cost.

The reformer and the fuel cell stacks are placed together so that the heat rejected by the fuel cell stacks can be utilized for the natural gas reformation process.

4.4.2 Split configuration

The reformer is placed in the central site where it converts the fuel to Hydrogen as highlighted in Figure 11. The fuel is transported to the central site by a pipeline network. The power and heat required are produced in each building by a PEFC system.



R1, R2, and R3: Residential heat and power loads, PEFC: Polymer electrolyte fuel cell stacks

Figure 11: Split co-generation system layout

Technical assumptions

- The size of the reformer is calculated from the sum of demand for all the buildings.

- Hydrogen is used in the burner.

- There are no heat losses from the fuel cell due to its position inside the building. Since the heat dissipation cannot be utilized for reformation process, the system efficiency is relatively low as compared to the previous configuration.

Economic assumptions

- The cost of heating pipes is negligible because the heat is produced inside the individual residential block.

- The cost for buildings and help equipment is 10% of the system cost.

- The cost for land improvement is 5% of the system cost

One drawback with this configuration is that there is no possibility to use the anode exhaust gas from the fuel cell in the steam reforming step (refer to the assumptions above). This means that some of the fuel must be used to give the central reforming process the required energy.

4.4.3 Local configuration

Figure 12 illustrates that the power and heat are produced in each building by an individual PEFC system. The fuel is transported to the individual location site F1, F2 and F3 represent individual cogeneration utility system.

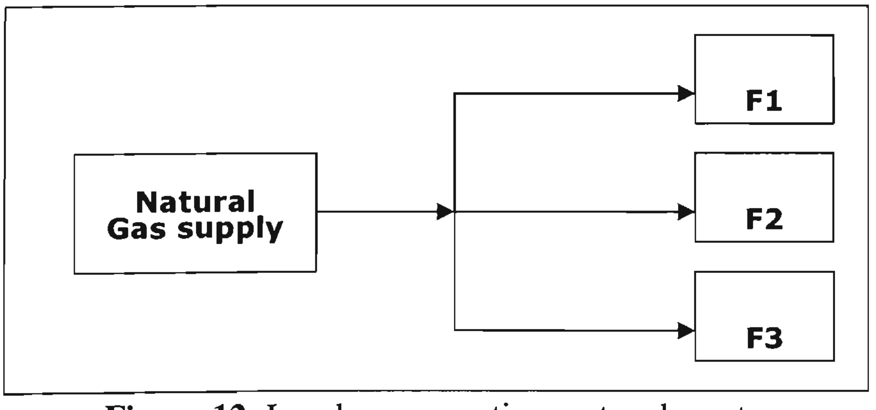


Figure 12: Local co-generation system layout

Technical assumptions

- There are no heat losses, except for the system exhaust gases, from the fuel cell system.

Economic assumptions

- The cost of heating pipes is negligible.

- The cost for buildings and help equipment is only 5% of the system costs where pipelines are not required.

- The land improvement cost is negated due to localization of the system inside the buildings.

The reformer and PEFC are placed together, which gives the opportunity to use the heat streams as effectively as possible. There are a few drawbacks of placing the system in the building. The heat loss in the process goes to the building.

4.4.4 Benchmark configuration

The reference system does not produce any power; instead it buys all the power from the grid. Gas burner supplies all the heat demands in the building. A water tank is localized in each building and is use to cover the sudden changes in the heat demand. The same type of fuel and fuel transportation is used as in the previous three configurations.

5. COST ESTIMATIONS

5.1 Standard case

The calculations are done for a standard case and then a sensitivity analysis is done to see how the different parameters affect the total cost. This is done for three configurations with respect to two demand approaches. The standard case is the one in which the values of the independent input variables as shown in Table 16 are taken as the constant standard values from the various sources.

Table 16: Data used in the standard case

Parameters	Natural Gas	Units
Fuel price, PR_{fuel} [32]	0.03	$/kWh$_{fuel}$
Fuel pipeline cost PR_{fp} [78]	105	$/m
Hydrogen pipeline cost PR_{hp} [5]	665	$/m
Heating pipeline cost PR_{hep} [29]	425	$/m
System depriciation time, Ds	20	years
Pipeline depriciation time, Dd	40	years
Interest rate, I	8	%
Number of buildings, Nb	100	
Price of sold power, $PR_{el,sell}$ [79]	0.18	$/kWh$_{el}$
Price of bought power, $P_{rel,bought}$ [79]	0.13	$/kWh$_{el}$
Exchange rate, EX	1.3	Aus. $/U.S $
Energy tax on fuel [32]	0.003	$/kWhfuel
Power bought from the grid, P_{bought} [75]	304/513 *	kWh/year
Additional heat needed, Qb	0/1066 *	kWh/year
Average heat demand, Q_{demand}	5330	kWh/year
Average power demand, P_{demand}	1900	kWh/year
Distance from fuel source to central site, dsc	1000	M
Distance from central site to building, dcb	500	M
Heat loss in pipes, Qhep [29]	0.015	kW/m
Power efficiency of fuel cell system [80]	0.35	Usable power/ LHV Fuel
Base cost of fuel cell system PRkW [77, 81]	1500	US $/kWel

* The first value is the first demand approach where all the heat is supplied by the fuel cell system. The second value is for demand approach number two.

5.2 Simulation tool

For the calculations, the code is written in Visual basic editor and linked to Microsoft Excel macros. The excel document is divided into different sheets, which are linked to each other. There is one configuration sheet, one input and result data sheet, one demand and standard value sheet, fuel sheets and a variation sheets.

In the configuration sheet, the three different configurations are shown. In the "in and result data" sheet, it is possible to choose the distances from the building to the fuel source and it is possible to choose between the two demand approaches. The main calculations are done in the fuel sheet where it's also possible to change the general standard values and the input of demand approach. The main calculations are done in the fuel sheet, where it is possible to change the standard values for the fuel. In the variation sheet it is possible to vary different parameters and see how they affect the result. The structure of the excel document is shown in Figure 13.

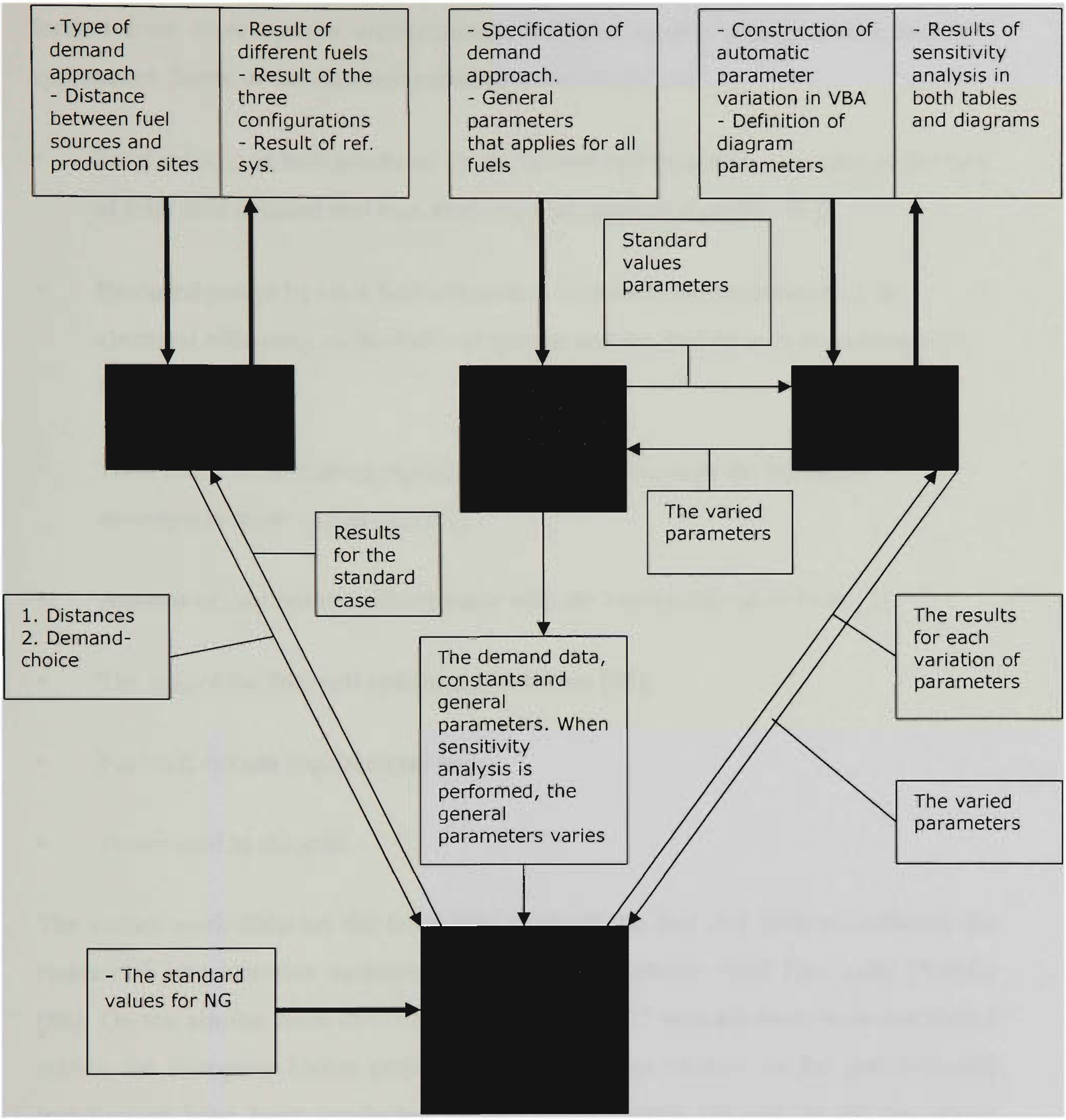


Figure 13: The structure of the excel sheets used in the calculation [The blue boxes represent the excel sheets. The thick arrows represent the external communication with the user. The narrow arrow represents the internal flow of information.]

5.3 Technical and economic factors considered in the calculations

The calculations are divided into a technical and an economy part. The equations of the calculations are described in a separate chapter dealing with the equations.

Several different technical parameters are calculated for the 12 possible combinations formed from three system architectures, two heat supply strategies and two cost approaches. Some of the different parameters calculated are:

- Total amount of heat produced by all the fuel cell systems considered as the sum of total heat demand and heat loss in the heating pipeline [82, 83],
- Produced power by each fuel cell system considered is the product of the electrical efficiency of the fuel cell system and the fuel flow in the reformer [3, 84],
- Total heat lost in heating pipelines is calculated through the technical assumption made earlier [82, 83],
- Amount of fuel fed to each reformer with the expression taken from [3],
- The size of the fuel cell system derived from [85],
- Fuel cell system requirements and
- Power sold to the grid.

The earlier work done on the feasibility study of the fuel cell systems included the residential co-generation systems powered by Phosphoric Acid Fuel cells (PAFC) [86]. On the similar lines the test programs on PEFC systems have been conducted within the European Union project [87]. Subsequent studies on the real fuel cell installations have been conducted in various literatures [88-90]. In all the above studies, the cost breakup of the system installations has been in the form of fixed and variable cost components. Thereby in the economy part of this feasibility study done in the Australian environment, the cost consists of:

- The capital cost, which is the annual investment cost ($/year)
    - Fuel cell system: This part of the major capital investment is a crucial component of the feasibility analysis. In this study, two types of cost approaches have been applied while computing the system costs. The detailed computations have been discussed in the later section.

- Burner: The cost of burner has been discussed only in demand approach 2 (partial heat supply). The cost of the natural gas burner is assumed to be $ 325 AUD. [32]

- Buildings and help equipment: As per the assumptions made by [91, 92], the cost for buildings and help equipment and land improvements account for 10 % of the system costs.

- Land improvements

- Variable cost ($/ year)

  - Distribution system (an external owner is assumed for the distribution system): The capital cost of the distribution system is considered as the product of the total pipeline cost and the annuity factor of the distribution system [82, 91].

  - Fuel pipeline

  - Hydrogen pipeline

  - Heating pipeline

  - Transport by truck (not considered in the study)

  - Operation and maintenance cost of the distribution system is assumed to be negligible [90].

  - Operation and maintenance cost of the fuel cell system: The expression for operation and maintenance cost in the first cost approach has been derived by [93] and has been used in the similar study done in [90]. In the non linear cost approach, the expression derived for PEFC system for mobile applications has been considered [94].

- Operation and maintenance of the system cost (i.e. Reformer, electronics, piping, power cables etc.): As per the work done in [91] this cost is assumed to be 10% of the total system cost.

- Fuel cost: Fuel cost is assumed to be 0.03 \$/kWh [48, 75].

- Power bought from the grid: the price of bought power is 13 cents/kWh [75]

- Power sold from the grid: The price of sold power is taken from [75] as 0.15 \$/kWh.

- Unforeseen expenses: as per [91], the unforeseen expenses are 10% of the total system cost.

- Fuel tax deduction: [2] gives the co-relation between the Energy tax, carbon dioxide and the total system efficiency and its impact on the total fuel taxation incurred. The expression derived is considered for the computations.

At the current moment, the residential fuel cell installations have not been commercialized in Australia. The interest from financing bodies on such an investment is unknown. However for analysis, the interest rate as assumed in [90, 91] is taken to be 8% per annum.

5.4 Theory behind the fuel cell system cost

The most common and the feasible way of approximating the cost of fuel cell systems is to use the constant cost per fuel cell capacity, \$/kWel. In this study two different cost estimations are applied, one with the constant cost and one where consideration is taken to the beneficial scaling effects.

In the first approach, the usual way (constant cost per kWel) of calculating the costs of a fuel cell system is used. When the capacity rises, the price for the fuel cell system (PEFC) rises proportionally. The price used in the study is, PR_{kW} =1500 \$/kWel. where the price given by the different companies span between \$ 1000 and \$ 2000, where \$ 1000 is a near future target cost.

The equations used in the first approach for all three configurations:

Total fuel cell system cost = PRkW . PFCmax . Nb. (1)

For example if there are 100 buildings and each building has a 2 kWel fuel cell system, the total fuel cell system cost becomes 1500. 2. 100 = $ 300 000.

In the second approach, a cost assumption that depends on the size of the fuel cell system has been used (see below), taken from reference [94]. These costs are developed for mobile applications but the authors have used them for stationary applications. The price is divided into the three most expensive parts included in a fuel cell system. Only the cost ratio of the different components is used in this study. The cost is instead based on $1500 for a 1 kWel system. Equations 2 to 5 show how the cost is divided between the different components as a function of power capacity.

Fuel processor (reformer) ($)	$320 + 36.\ P_{FC,\ max}$	(2)
FC stack, blower & cooling ($)	$1073 + 22.P_{FC,\ max}$	(3)
PC electronics ($)	$840 + 97.P_{FC,\ max}$	(4)
$\sum$ Total system cost ($)	$2233 + 155.\ P_{sys,\ max}$	(5)

The cost ratio is described in equation (6) to (8)

$$A_{REF} = (320 + 36.\ P_{FC,\ max}) / (2233 + 155.P_{sys,\ max}) \quad (6)$$

$$A_{FC} = (1073 + 22.\ P_{FC,\ max}) / (2233 + 155.P_{sys,\ max}) \quad (7)$$

$$A_{elec} = (840 + 97.\ P_{FC,\ max}) / (2233 + 155.P_{sys,\ max}) \quad (8)$$

5.4.1 Assumptions

- The cost (PR_{kW}) for a 1 kWel fuel cell system is $ 1500 US.
- A scale factor (0.8)is used to consider scaling effects
  The equation used: Cost (Pnew) = Cost (P_{old}). (Pnew/ Pold) EXP 0.8.
- In the split case, the cost for electronics is divided equal between the fuel cell and the fuel processor (reformer).

5.4.2 Central configuration

In the central configuration, a large fuel cell system provides all the buildings with power and heat. Due to the high capacity required and the limited availability of large commercial fuel cell systems , the fuel cell system is divided into 250 kWel fuel cells and complementing fuel cell. For example if the total need of power is 560 kW, the calculation is done for two 250 kW fuel cells and one 60 kW fuel cell.

Total cost for all the fuel cell system [10, 94]:

$1500. (P_{FC, comp}/1)$ EXP $0.8 + N_{FC, 250}. (1500. (250/1)$ EXP $0.8)$

$P_{FC, comp}$ = the size of the complementing fuel cell.

$N_{FC, 250}$ = Number of 250 kW fuel cell systems

5.4.3 Split configuration

In the split configuration, there is a fuel cell in each building and a large reformer that supplies hydrogen to all the buildings.

The cost for a fuel cell system inside the building for a fuel cell and 50 % of the electronics is added to the first cost.

The total cost for all the fuel cell systems [92, 94]:

$N_b. (1500. ((P_{FC, split} / 1) ^\wedge 0.8). (A_{FC *} + 0.5\ A_{elec *})) + 1500. (P_{FC, split}. N_b/1)$ EXP $0.8). (A_{REF} + 0.5\ A_{elec})$

In A^*_{FC}, $P_{FC, max} = P_{FC, split}$ (The part that is FC)

In A^*_{elec}, $P_{FC, max} = P_{FC, split}$ (The part that is electronics)

In A_{elec}, $P_{FC, max} = P_{FC, split}. N_b$ (The part that is electronics)

In A_{REF}, $P_{FC, max} = P_{FC, split}. N_b$ (The part that is reformer)

$P_{FC, split}$ = the size of the fuel cell in each building.

5.4.4 Local configuration

There is a fuel cell system in each building.

Total cost for all the fuel cell systems [92, 94]:

$1500. ((P_{FC,\, local}/ 1) \wedge 0.8). N_b$

$P_{FC,\, local}$ = the size of the fuel cell in each building.

6. RESULTS AND DISCUSSIONS

6.1 Calculation results

The results from the calculations in the standard case are shown in Table 17. The standard case is described closer in chapter 6. The results are shown for the two demand approaches and two cost approaches.

Table 17: The cost for the energy company to supply 100 buildings with power and heat demand in standard case

	Demand approach	Central $/year	Split $/year	Local $/year	Reference $/year
Cost approach Linear	1*	194,365	235,014	140,097	59,854
	2**	134,091	148,853	123,319	59,854
Cost approach Scale factor	1*	90,919	155,953	118,249	59,854
	2**	73,960	120,897	110,635	59,854

* The fuel cell system supplies all the heat needed by the buildings. In the linear approach, a linear fuel cell system price is used (2100 $/ kWel)

** A main part of the buildings power demand is supplied by the fuel cell system. The part of the heat not supplied by the fuel cell system is covered by a gas burner.

The reference system is much cheaper than the fuel cell systems. Table 17 shows that the cheapest (73,960 $/year) combination with the central architecture, demand approach 2 (partial heat supply) and cost approach 2 (Scaling factor). It also shows that the most expensive (235,014 $/year) combination is with the split configuration, demand approach 1 (full heat supply) and cost approach 1 (linear).

Table 18 & 19 presents how the total cost is divided into capital costs and variable costs. Table 18 shows the linear cost approach and Table 19 shows the scaling factor approach. The results in both tables concerns natural gas.

Table 18: Share of capital and variable costs for linear cost approach

Cost approach, Linear	Demand approach	Central (%)	Split (%)	Local (%)
Capital cost of system	1*	45	45	43
Total variable cost	1*	55	55	57
Capital cost of system	2*	36	35	38
Total variable cost	2*	64	65	62

Table 19: Share of capital and variable costs for the scale factor cost approach

Cost approach, Scale factor	Demand approach	Central (%)	Split (%)	Local (%)
Capital cost of system	1*	29	38	38
Total variable cost	1*	71	62	62
Capital cost of system	2*	18	29	36
Total variable cost	2*	82	71	64

Tables18 and 19 show that the variable cost is higher than the capital cost for all the cases. The variable cost includes the distribution costs (installation cost for the pipelines), but these are not the major cost parts. The major part of the variable cost consists of the fuel cost. In both the cost approaches, demand approach 2 (full heat supply) has a higher percentage of variable cost than demand approach 1 (partial heat supply).

If Table 18 is compared to Table 19, it can be seen that when using cost approach 1 (linear) the percentage of capital cost is higher than in cost approach 2 (scale factor). In cost approach 2, consideration is taken to the benefits of scaling up the system. Figure 15 & 16 shows how the total cost and capital cost respectively are divided into different cost elements for the central configuration.

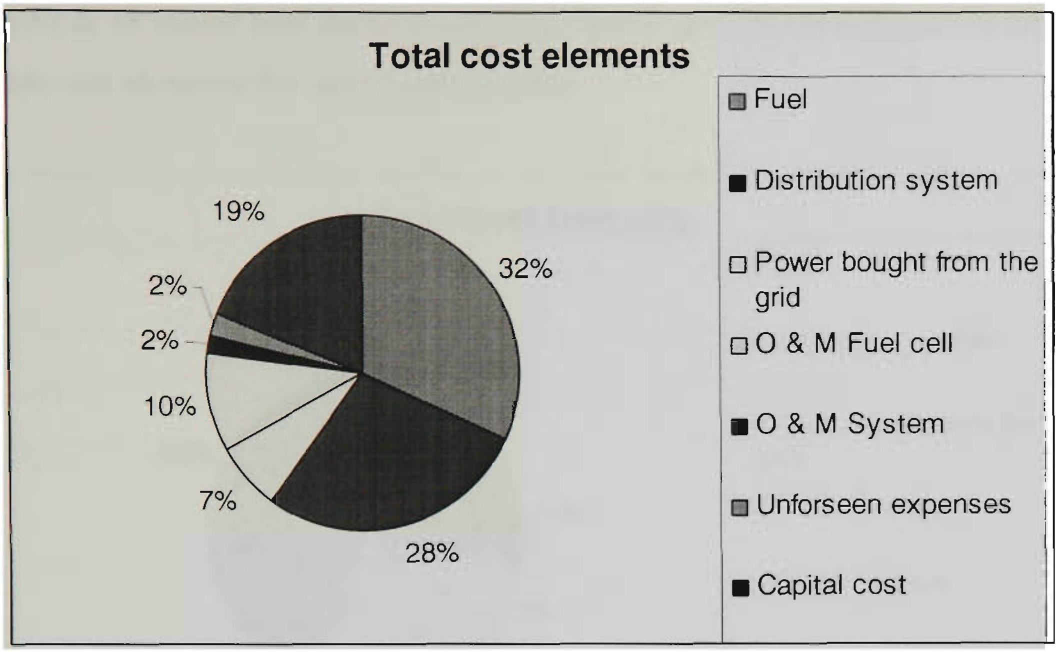


Figure 15: The distribution of different cost elements that is included in the total cost. The total cost is the cost for supplying 100 buildings with power and heat. [The figure shows the total cost for central configuration, cost approach 2 (scaling factor) and demand approach 2 (partial heat supply).]

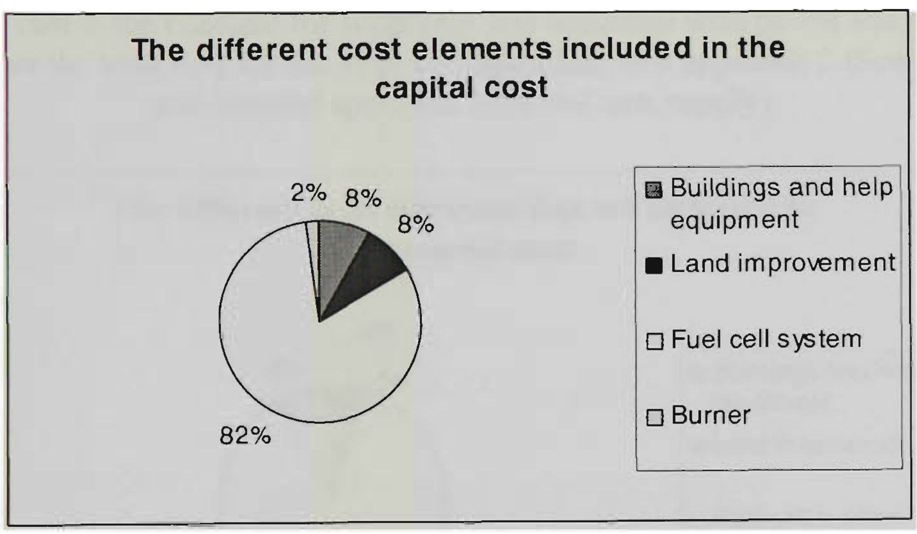


Figure 16: The distribution of different cost elements that are included in the capital cost. The capital cost is the cost per year for the investment cost of the production system. The system supplies 100 buildings with power and heat. The figure shows the capital cost for the central configuration, cost approach 2 (scaling factor) and demand approach 2 (partial heat supply)

Figures 15 shows that the fuel cost is the major cost element; this means that the system is strongly dependent of the fuel price. This result is consistent with the results obtained in [77]. Figure 16 shows that the largest part of the capital cost consists of the fuel system cost.

Figure 17 & 18 shows how the total cost and capital cost respectively, are divided into different cost elements for local configuration.

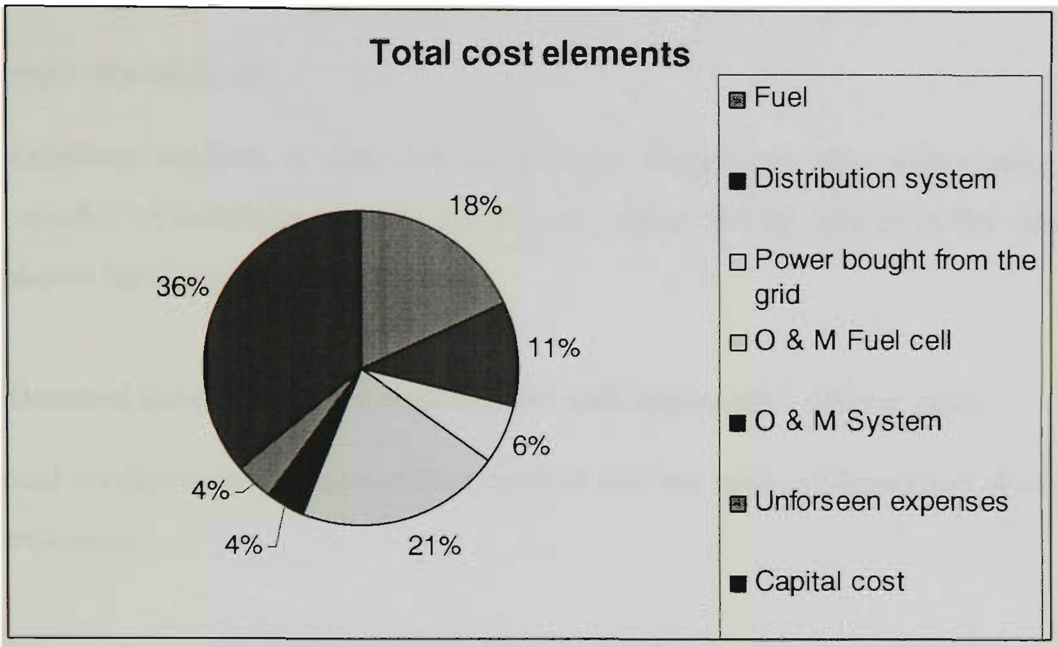


Figure 17: The distribution of different cost elements that is included in the total cost. The total cost is the constant for supplying 100 buildings with power and heat. The figure shows the total cost for the local configuration, cost approach 2 (Scaling factor) and demand approach 2 (partial heat supply)

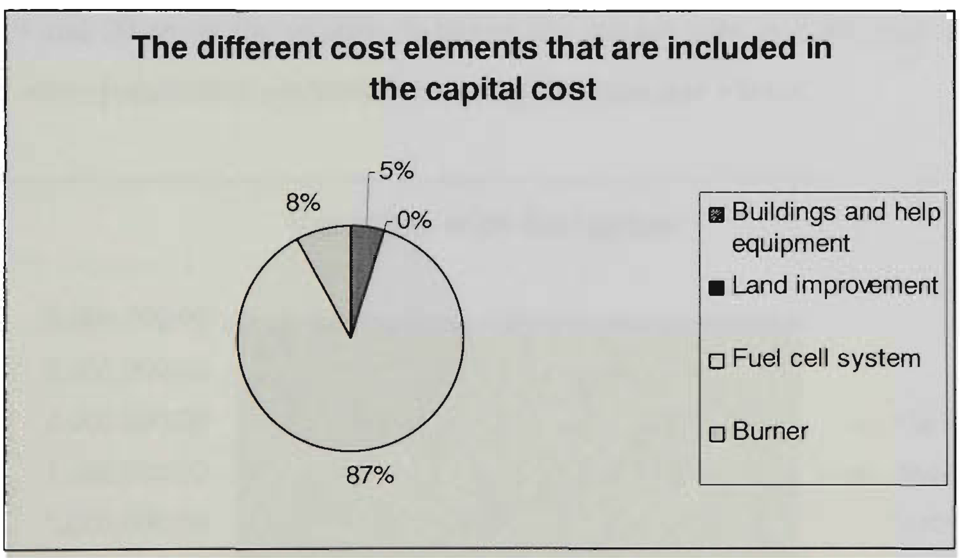


Figure 18: The distribution of different cost elements that are included in the capital cost. The capital cost is the cost per year for the investment cost of the production system. The system supplies 100 buildings with power and heat. The figure shows the capital cost for the local configuration, cost approach 2 (scale factor) and demand approach 2 (partial heat supply)

Figure 17 show that the fuel price is the largest cost element. The capital cost, O & M costs and unforseen expenses also have considerable impact on the total cost. The

Figure 18 shows that the capital cost mainly consists of the fuel cell system cost. The price of the burners stands for approximately 8% of the capital cost. Two calculations which are done with standard parameters, are shown in excel sheets later.

6.2 Sensitivity analysis

The sensitivity analysis is done for natural gas. Parameters like power price, fuel price, number of buildings, scale factor etc. are varied and the results of the total cost is displayed both in tables and diagrams.

6.2.1 Demand case 1 (full heat supply) and cost approach 1 (linear cost)

The local configuration is always the cheapest and the split configuration always the most expensive.

6.2.2 Demand case 2 (partial heat supply) and cost approach 1 (linear cost)

The analysis shows that the local configuration is the cheapest in most of the cases and the split configuration, the most expensive. In the cases where the fuel price is decreased or the power price is increased, other results are attained.
Figures 19 and 20 show the relation between the system cost and the fuel and power price. All other parameters are held constant at the standard values.

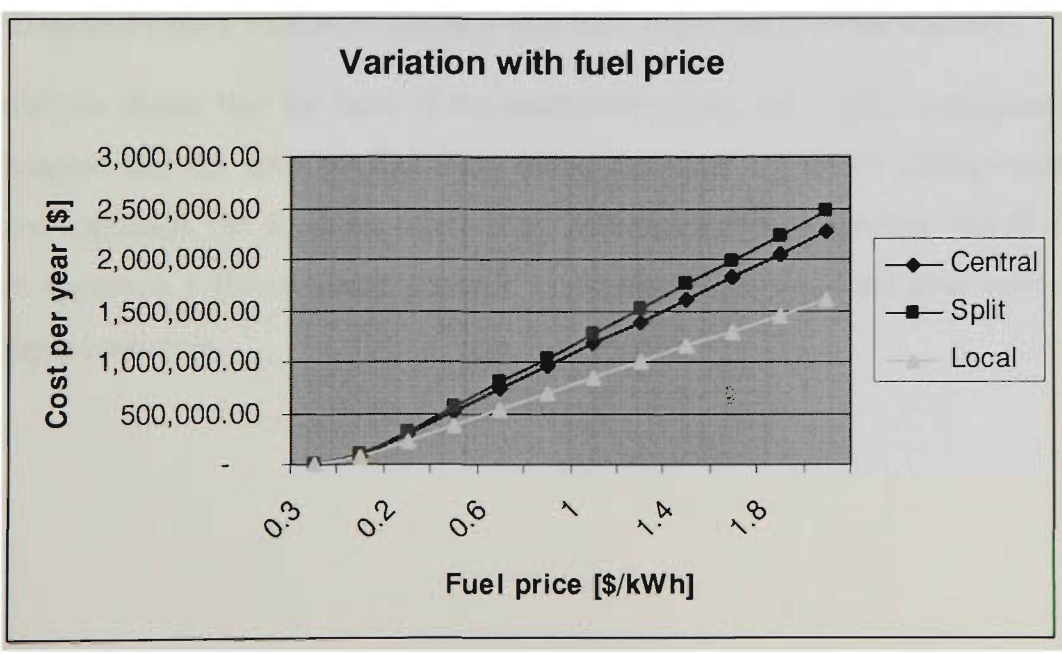


Figure 19: The variation of annual cost for 100 buildings with respect to the variation of fuel price for linear cost approach and partial heat supply strategy

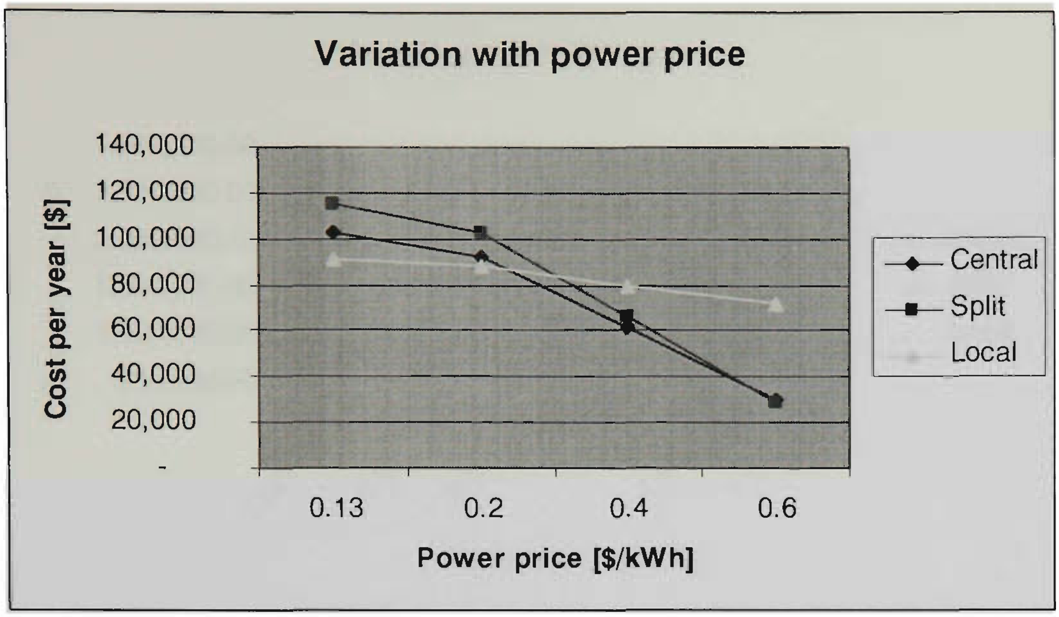


Figure 20: The variation of annual cost for 100 buildings with respect to the variation of power price for linear cost approach and partial heat supply strategy

Figure 19 shows that at all prices of natural gas (including CO_2 tax and energy tax), the local configuration is the cheapest.

Figure 20 shows that at power prices (not including network fee and power tax) of approximately 0.27 $/ kWhel and above, the central configuration is the cheapest. It is also possible to see that at power prices of approximately 0.25 $/kWhel and above, the split configuration is cheaper than the local configuration.

6.2.3 Demand case 1 (full heat supply) and cost approach 2 (scale-factor)

The analysis shows that for most of the parameter values, the central configuration is the cheapest and the split configuration being the most expensive configuration. In this cost approach, the costs are much more affected by the parameter variation than in cost approach 1 (linear cost). Figures 21-22 show how the total cost varies with different parameters.

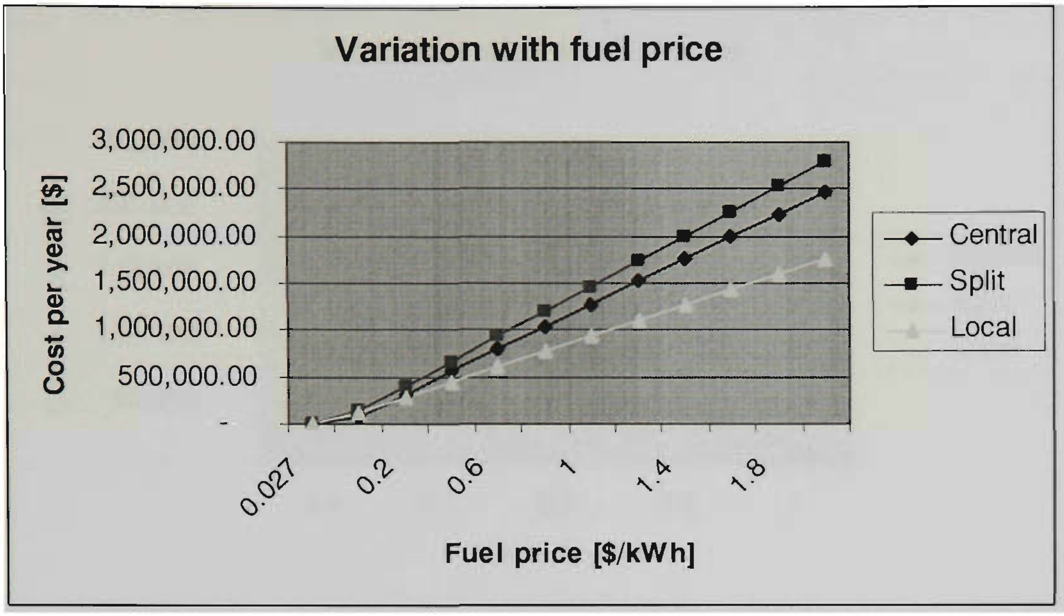


Figure 21: The variation of annual cost for 100 buildings with respect to the variation of fuel price for scaling factor cost approach and full heat supply strategy

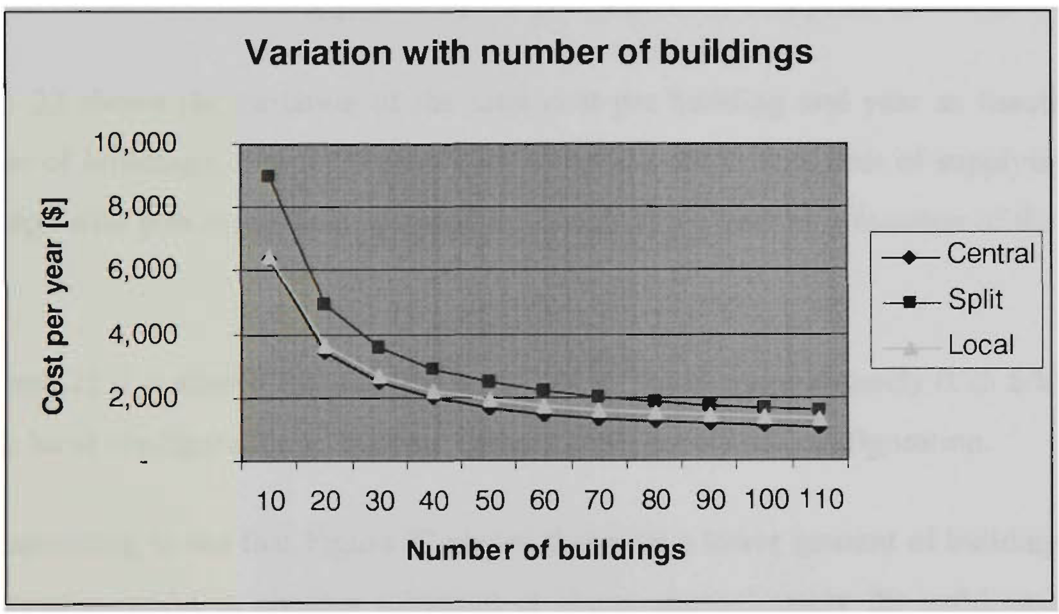


Figure 22: The variation of annual cost per building with respect to the variation of number of buildings for scaling factor cost approach and full heat supply strategy

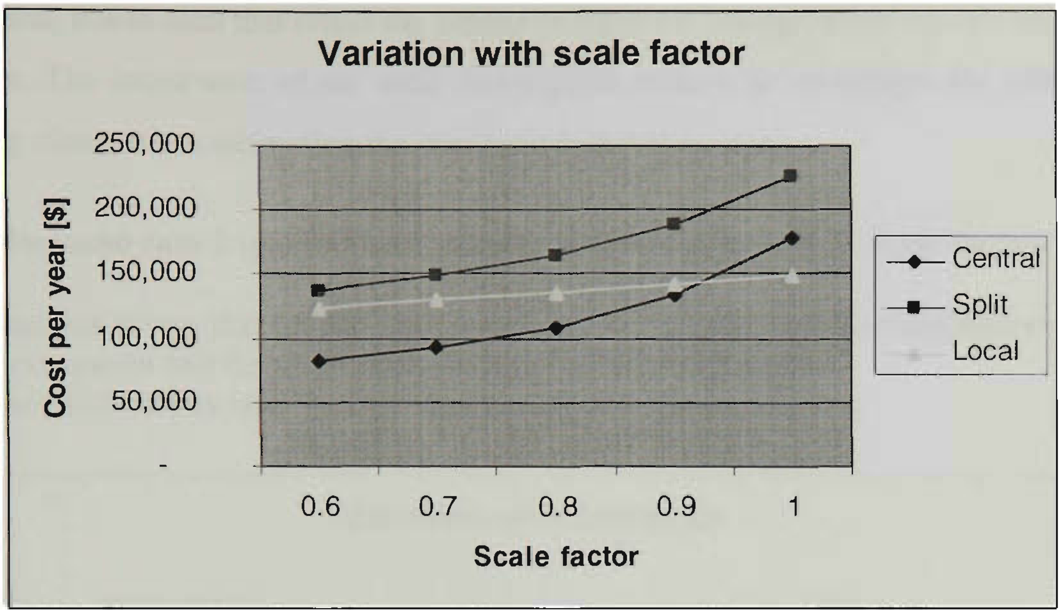


Figure 23: The variation of annual cost for 100 buildings with respect to the variation of scale factor for scaling factor cost approach and full heat supply strategy.

Figure 21 show the variation of the total cost of supplying 100 buildings with power and heat demand (demand approach 1) per year where the fuel price is varied.

Figure 22 shows the variation of the total cost per building and year as function of number of buildings. Figure 23 shows the variation of the total cost of supplying 100 buildings with power and heat (demand approach 1) per year as a function of the scale factor.

In Figure 21 it is shown that the fuel price has to rise to approximately 0.25 $/kWh_{NG}$ for the local configuration to become cheaper than the central configuration.

It is interesting to see that Figure 22 shows that with a lower amount of buildings, the local configuration is cheaper (changes at about approximately 20 buildings) This depends partly on the economies of scale, which gives a lower total cost per building for central configuration if the total number of buildings is increased. Another thing that affects the cost in the central configuration is the heat losses in the heating pipelines. The heat loss is grater per total amount of heat transported with fewer buildings than with more buildings.

In figure 23 the effect of using the scale factor is shown. The scale factor is 0.8 in cost approach 2; this is higher than the most of the scale factors used in the industry. Cost approach 1 corresponds to a scale factor of 1. Depending on which scale factor that was used, it was seen that either the central or the local configuration was the cheapest system. The importance of the scale factor gives reasons to investigate the effects of scaling closer when estimating the cost for a fuel cell system.

6.2.4 Demand case 2 (partial heat supply) and cost approach 2 (scale factor)

The analysis shows that for the most parameter values, the central configuration is the cheapest system and the split configuration, the most expensive.
Figures 24-27 shows how the cost varies with different parameters.

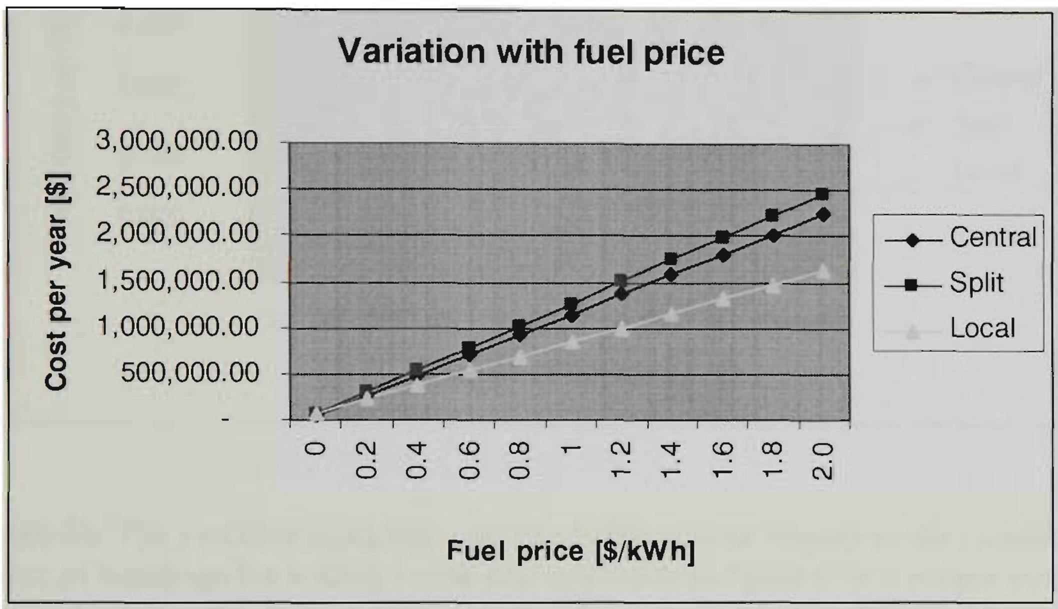


Figure 24: The variation of annual cost for 100 buildings with respect to the variation of fuel price for scaling factor cost approach and partial heat supply strategy

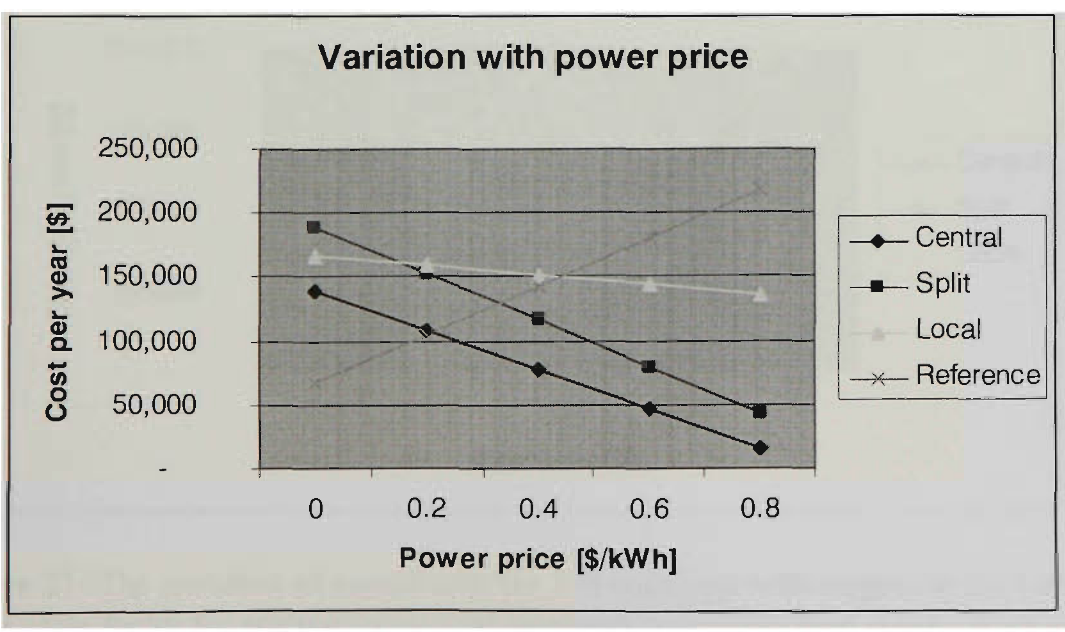


Figure 25: The variation of annual cost for 100 buildings with respect to the variation of power price for scaling factor cost approach and partial heat supply strategy

Both the figures show the variation of total cost of supplying 100 buildings with power and heat (demand approach 2) per year. In figure 24, the fuel price (including Carbon dioxide and energy tax) and in figure 25, the power price, (not including network fee and power tax is varied. The reference system is included in figure 25.

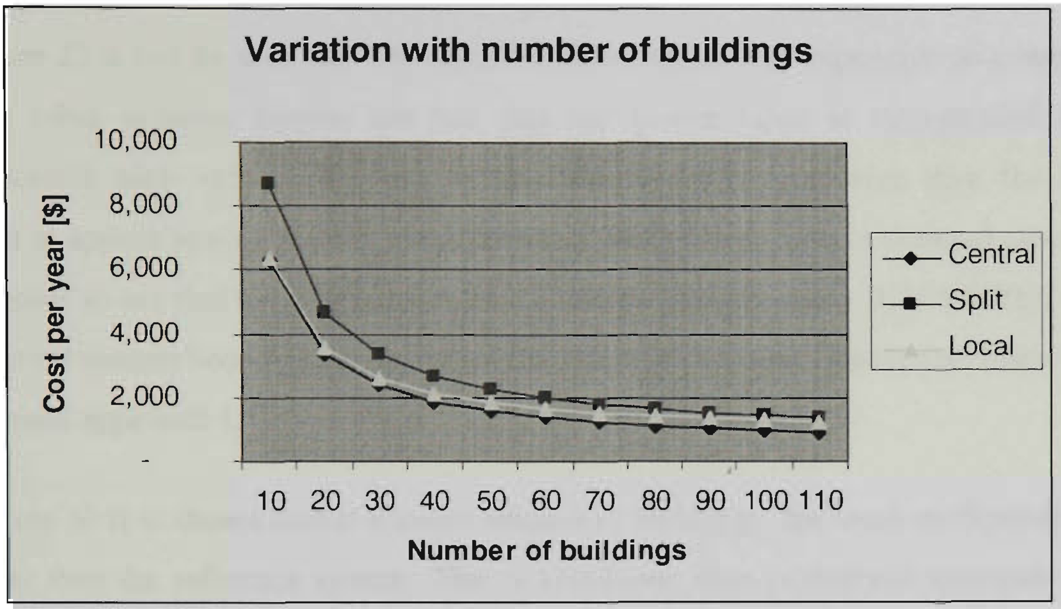


Figure 26: The variation of annual cost per building with respect to the variation of number of buildings for scaling factor cost approach and partial heat supply strategy.

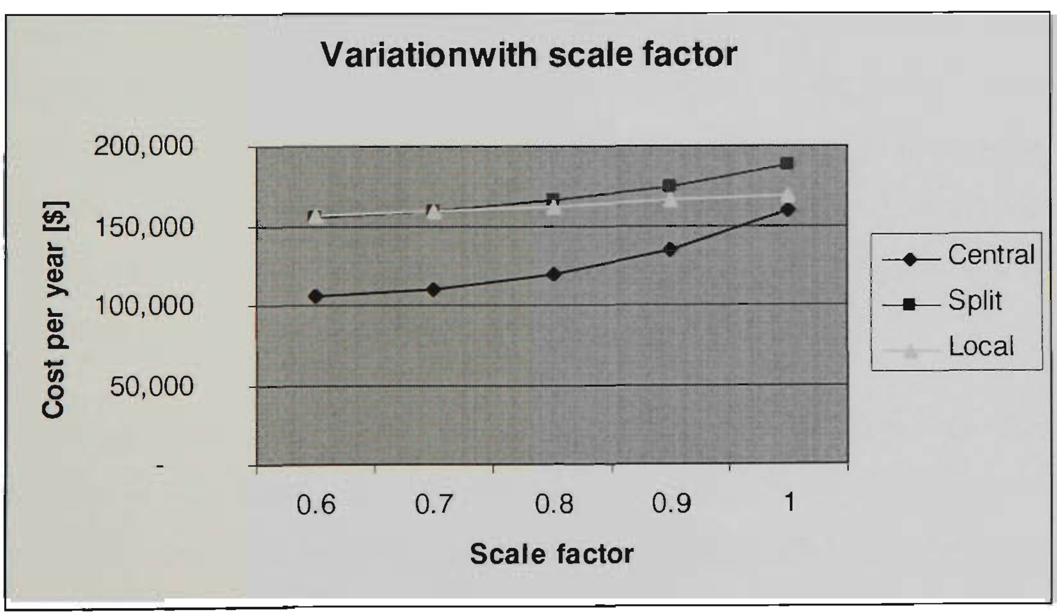


Figure 27: The variation of annual cost for 100 buildings with respect to the variation of scale factor for scaling factor cost approach and partial heat supply strategy.

Figure 26 shows the variation of the total cost per building and year as the function of the number of buildings. Figure 27 shows the variation of the total cost of supplying

100 buildings with power and heat (demand approach 2) per year as a function of the scale factor.

In figure 24 it can be seen that the fuel price has to rise to approximately 0.28 $/kWhNG until the local configuration becomes cheaper than the central configuration.

In figure 25 it can be seen that the central architecture is less expensive as compared to the other systems despite the fact that the power price is incremented by a significantly high value. The split system becomes less expensive than the local system at approximately 0.2 $/kWhel, which is much lower than in demand case 1. It is possible to see that the power price has to rise to approximately 0.27 $/kWhel until the central system becomes cheaper than the reference system. This is also lower than in demand approach 1.

In Figure 30 it is shown that at a lower amount of buildings, the local configuration is cheaper than the reference system. This is also lower than in demand approach 1. In Figure 31, the differences of using a scale factor are not shown. It is possible to see that the scale factor does not affect the configurations that are the cheapest ones for all scale factors.

7. CONCLUSION AND RECOMMENDATION

7.1 Conclusion

The first aim of the study was to make a survey Power and heat infrastructure and some of the available fuels in Australia that can be used as transitional tools for implementation of fuel cells. It is clear from the study that the usage of natural gas is anticipated to increase in the domestic sector. The numbers of households that have an access to natural gas resources are gradually increasing. The production of biogas is also increasing but there is a limit on its usage. Biogas is currently used for power production and projects are underway for exploiting these resources for domestic co-generation. There can be a possibility of using biogas for fuel cells located near bio gas plants.

Ethanol will mainly however be used for transport applications. The fuel cell systems could be used in facilities like hospitals and other premises with high demand for reliability.

The next objective of this study was to estimate the cost of supplying a specified demand of heat and power with a fuel cell system. When comparing the cost of different fuel cell system architectures considered in analysis with benchmark configuration, it is clear that it is not economically viable to install a fuel cell system. The benchmark configuration has smaller fixed and variable costs. For the fuel cell system to compete with the reference system, the cost of the grid power must increase considerably. It is also essential that the fuel cell lifetime is also increased. In the future the costs of fuel cells will decrease, not just due to technical improvements but also due to the fact that fuel cells will be produced in high volumes.

When comparing the different configurations, it can be seen that the local configuration is best when there are only a few buildings to supply with power and heat. As the number of buildings increases, it becomes better to use the central configuration.

Cost approach 2 (scale factor) is generally more expensive than cost approach 1 (linear). Cost approach 2, is an attempt to take the scaling benefits into account. This study shows that it is necessary to investigate the real scaling effects more thoroughly before an accurate cost estimation of the system cost. Cost approach 2 is not a precise model since significant a number of assumptions have been made.

Demand approach 1 (full heat supply) is generally more expensive than demand approach 2 (partial heat supply), which primarily depends upon the relatively higher fuel cell system costs and its maintenance. Another reading that has been consistent throughout the studies is that the split system is the most expensive combination. This is due to the fact that lower efficiencies have been assumed for this configuration than the others. When further investigation and research has been done, on how to optimise the split configuration, better assumptions can be made.

The reference system is the cheapest in the studied location than the fuel cell systems in all the three architectures mentioned. If the price of power would rise, the fuel cell system would have the possibility to compete economically with the reference system. However the fuel cell system gives the reliability and will secure the delivery of power if there is a power breakdown, and could be competitive in other locations.

The split configuration will not be competitive due to difficulties of using the synergy effects between the system components. It is clear that it is important to consider the scaling effects, both economic and technical.

A much closer investigation has to be done on the system to be able to evaluate these effects. In cost approach 2 where considerations have been taken for scaling effects, the total cost of supplying the calculated system with power and heat is higher than in cost approach 1 without scaling effects.

When choosing the demand approach, consideration has to be taken to what the customer wants. Demand approach 2 where a limited power is supplied, is cheaper than demand approach 1 where all heat demand is supplied. Demand approach 1 is probably more environmental friendly than demand approach 2, as a burner is used to supply heat not supplied by the fuel cell system.

For power and heat generation with a fuel sell system, the best opportunities would be probably near natural gas pipeline and with a central configuration that includes a reformer and fuel cell stack. The central configuration should be used where there are large amount of buildings that require power and heat. If a small number of buildings need power and heat, the local configuration should be used and the fuel should probably be delivered by truck.

7.2 Recommendations for future work

The recommended future work can include:

- A more extensive research of the reforming process for each fuel (efficiencies, costs etc.).

- A study to optimize each system architecture design.

- A study of the effects of scaling on the system with both efficiencies and economies in mind.

- When more detailed data regarding system performances are found (fuel compatibility etc) a geographical localization study can be done.

- After the above studies have been completed, cost estimations of using fuel cell stacks for tri-generation can be carried out to near accuracy.

REFRENCES

[1] C. Andrews, "Visions of Hydrogen Future," in IEEE Power and Energy, vol. 2, 2004, pp. 23-25.

[2] P. Alvfors, C. Wallmark, "Technical design and economic evaluation of standalone PEFC system for buildings in Sweden," Journal of Power Sources, vol. 118, 2003, pp. 358-356.

[3] P. Alvfors, C. Wallmark, "Design of stationary PEFC system configurations to meet heat and power demands," Journal of Power Sources, vol. 106, 2002, pp. 83-92.

[4] M. Mahajan, A. Maung Than Oo, A. Kalam, "Renewable Hydrogen based Distributed Power generation systems," Proceedings of the ICECE, Bangladesh University of Engineering and Technology, Dhaka, 2004, pp. 172 -176.

[5] C. Wallmark, "Design and evaluation of stationary polymer electrolyte fuel cell systems," Department of Chemical Engineering and technology, KTH-Royal Institute of technology, Stockholm, 2004, pp. 6-9.

[6] E. Justi, "A solar hydrogen energy system," ISBN 0-306-42150-X, Plenum, New York, 1987.

[7] J. Ogden, "Hydrogen: the fuel of the future?" Physics Today, vol. 55, 2002, pp. 69-75.

[8] J. Petrovic, "Challenges to hydrogen production, delivery and storage," USDOEs program response, 2003 Fuel Cell Seminar, Miami Beach, 2003.

[9] T. Biegler, "Fuel cells - a perspective," in ATSE Focus, 2005, pp. 9-1

[10] Z. Barisic, "European field trial program with 250 kW PEM fuel cell power plants," Proceedings of The Fuel Cell Home, Lucerne, 2001, pp. 187-196.

[11] "The Fuel Cell Handbook," U.S Department of Energy, Morgantown, West Virginia, 2002, pp. 43-47.

[12] "Global fuel cell decentralized generation market assessment," E4Tech, London, 2001.

[13] T. Vezioglu, D. Das, "Hydrogen production by biological processes: a survey of literature," International Journal of Hydrogen Energy, 2001, pp. 13-28.

[14] R. Wurstler, W. Zittel, "Hydrogen in the Energy Sector," 1996, www.hydrogen.org, Accessed 2004.

[15] A. Bridgewater, "The technical and economic feasibility of biomass gasification for power generation," vol. 74, 5 ed, 1995, pp 631-653.

[16] C. Thomas, B. James, F. Lomax, I. Kuhn, "Fuel options for the fuel cell vehicle: hydrogen, methanol or gasoline?" International Journal of Hydrogen energy, 2000, pp. 551- 567.

[17] J. Hackney, R. de Neufville, "Life cycle model of alternative fuel vehicles: Emissions, energy, and cost trade-offs," in Transportation Research, Part A, 2001, pp. 234- 266.

[18] "Hydrogen Energy and fuel cells- A Vision of our future," European Commission Report, vol. EUR- 20719 EN, Luxembourg, 2003.

[19] G. Graham, "Assessment of implementation issues for fuel cell in domestic and small scale stationary power generation and CHP applications," ETSU F/03/00235/ REP DTI/pub URN 02/1349, 2002.

[20] "National Hydrogen study," ACIL Tasman, Department of Industry, Tourism and resources, Canberra, 2003.

[21] N. Galwey, "The Electricity supply industry in Australia," Electricity supply association of Australia, Melbourne, 1998, pp. 16-17.

[22] "Basslink feasibility study report," Hydroelectric commission of Tasmania, Hobart, 1991, pp. 33-36.

[23] "The Electricity supply industry in Victoria" the Office of State Owned Enterprises, Department of treasury, 1998, pp 21-22.

[24] "Statement of opportunities 1993-2005," National Grid Management Council, Canberra, 1993, pp 46- 47.

[25] L. Feld , "Australia- Country analysis briefs," 2004, http://www.eia.doe.gov/emeu/cabs/australi.html.

[26] K. Noble, I. Dalziell, Electricity grids and gas pipelines in Australia," ABARE, Canberra, 1993, pp. 29-31.

[27] Department of infrastructure, "Electricity: Generation and consumption," 2004, http://www.doi.vic.gov.au/Doi/Internet/Energy.nsf/0/A3C484E730A5A5B7CA256D5800030CD5?OpenDocument.

[28] "Electricity prices in Australia, "Electricity Supply Association of Australia Limited, Sydney, 2004, pp. 43.

[29] M. Ohlsson, "An investigation of Fuel cell economy and fuel availability for distributed generation in Sweden," in Energy processes- KTH, Royal Institute of Technology, Stockholm, 2001, pp. 7-15.

[30] Ausralian Bureau of statistics, "Year book Australia: Australian energy consumption allocated to final use," 2003,

http://www.abs.gov.au/Ausstats/abs@.nsf/Lookup/667FDCD244561935CA256CAE0015A743.

[31] Actewagl retail, "Natural gas: Distribution and usage," 2003, http://www.actewagl.com.au/.

[32] J. Osborne, Project engineer, Sustainable energy authority of Victoria, (Personal communication), 2005, Info@seav.com.au.

[33] E. Walker, Energy studies, Murdoch University, "Wood heaters and open fireplaces," 2004, http://reslab.com.au/resfiles/heaters/text.html.

[34] Enviro friendly products Pty Ltd, "How much does your hot water cost?" 2005, http://www.enviro-friendly.com/cost-of-hot-water.shtml.

[35] Australian greenhouse office, "Solar water heaters," 2003, http://www.greenhouse.gov.au/markets/mret/pubs/13_solar.pdf.

[36] "Flow systems," Alstom power, 2001, pp. 28-29.

[37] CIA Publications, "The world fact book: Australia," 2005, http://www.cia.gov/cia/publications/factbook/geos/as.html.

[38] Chemlink Pty Ltd., "Oil and gas in Australia," 1997, http://www.chemlink.com.au/gas.htm.

[39] B. Nagle, The International gas union, "Recent Developments in the Gas Industry in Australia," 2003, http://www.igu.org/members/developm_2003/Australia.pdf.

[40] Westwick-Farrow Pty Ltd., "Remote control of Natural gas flow," 2005, http://www.processonline.com.au/process/feature_article/item_022004a.asp.

[41] "Gas statistics Australia," The Australian gas association, Canberra, 2000.

[42] M. Maslund, "Energy gas techniques," Svenska Gasforningens Services, 1995.

[43] AMEC, "Gas pipelines in Australia," 2004, http://www.amec.com/services/servicessummary.asp?pageid=323.

[44] Envestra, "Australian Gas industry," 2003, http://www.envestra.com.au/files/pdf/EnvPros97_chpt3.pdf.

[45] M. Roarty, Science, technology, environment and resources group, "Natural Gas: Energy for the new millennium," 2001, http://www.aph.gov.au/library/pubs/rp/1998-99/99rp05.htm#PIPE.

[46] Energysafe Victoria, "Gas performance safety reports," 2004, http://www.ogs.vic.gov.au/performance/Review%20of%20Gas%20Safety%20-%20Main%20Report.pdf.

[47] Envestra, "Operational Info: Leakage through gas distribution pipelines," 2003, www.envestra.com.au/operational_info/files/SAFETY_CASE-V8-JK_10904.pdf+Leakage+through+gas+distribution+pipelines&hl=en&client=firefox-a.

[48] Origin energy Pty Ltd., "Origin energy standard natural gas prices," 2005, http://www.originenergy.com.au/business/business_pcode.php?postcode=3400&x=0&y=0&energy_type=G&home_business=B&pageid=989.

[49] C. Blowes, "Technical and capital cost issues of the proposed connecting pipeline between of the proposed connecting pipeline between the ACT network of AGL," Canberra, 2000.

[50] J. Thunnel, "Energy gas fact handbook," Svenskt Gas Technique Centre, 2000.

[51] P. Trotter, Australian greenhouse office, "Biomass: Food biomass to green energy," 2005, http://www.greenhouse.gov.au.

[52] Melbourne Water, "Land use at western sewerage treatment plant," 2003, http://www.melbournewater.com.au/404.asp?404;http://www.melbournewater.com.au:80/content/library/water_cycle/sewerage/western_treatment_plant/Future%20Land%20Use%20at%20Western%20Treatment%20Plant.pdf&bhcp=1.

[53] M. Thurlow, RM Thurlow Pty Ltd, "Renewable energy and Potential for income," 2003, http://www.thurlow.com.au/Jun%2002%20newsletter.htm.

[54] W. Petterson, "Full circle," Proceedings of First international symposium on distributed generation: Power and market aspects, Stockholm, 2000 pp. 243-264.

[55] B. Lindstrom, "Methanol reformer for fuel cell vehicles," Department of Chemical Engineering and Technology, KTH Royal Institute of Technology, Stockholm, 2000.

[56] J. Brown, Solar hydrogen research pty ltd, "Hydrogen and fuel cell markets for Australia," 2004, http://www.hydrogen.asn.au/Hydrogen-Economy.htm.

[57] "Handbook of compressed gases," CGA, Kluwer Academic Publishers,4th ed 1999.

[58] R. Bechold, "Properties, storage and dispensing and vehicle facility modifications," Society of Automotive Engineers, 1997.

[59] Shell Canada, 2004, http://www.shell.ca/code/products/oilsands/support//scotford_pipeline.html.

[60] AFDC, Alternative fuels data centre, "Properties of fuels," 2001, http://www.afdc.doe.gov/pdfs/fueltable.pdf.

[61] Methanol Australia, "Methanol: clean fuel for the future," 2001, http://www.methanol.com.au/_about-methanol.asp.

[62] Australian government: Department of environment and heritage, "Methanol," 2004, http://www.npi.gov.au/database/substance-info/profiles/54.html.

[63] Coogee Chemicals, "Gas to liquid ventures," 1994, http://www.yokogawa.com/suc/OilGas/suc-COOGEEen.htm.

[64] "Methanol refueling station costs," Science and Technology INC., 1999.

[65] The openroad motoring sevices, "The fuel guide," 2003, http://www.theopenroad.com.au/motoring_carcare_fuelguide.asp.

[66] BAFF, Bio alcohol fuel foundation, "Ethanol: wide raw material potential," 2000, http://www.baff.nu/english/ovrigt/presentationsmaterial.cfm.

[67] Manildra group, "Submission to fuel taxation enquiry," 2003, http://fueltaxinquiry.treasury.gov.au/content/Submissions/Industry/Manildra_247.asp.

[68] Department of energy, Oregon, "Biomass," 2002, http://www.energy.state.or.us/biomass/Tech.htm.

[69] Grains research and development organization, 2000, http://www.grdc.com.au/growers/res_upd/irrigation/04/rendell.htm.

[70] Australian automobile association, "The Viability of an ethanol industry in Australia," 2004, http://www.aaa.asn.au.

[71] Australian institute of petroleum, "Petroleum topic fact sheet: LPG," 2000, http://www.aip.com.au/industry/fact_liquid_gas.htm.

[72] "LPG: Its role in Australian energy," presented at ALPGA conference and exibition, Albury, 2003.

[73] L. Brown, "A comparative study for onboard hydrogen production for fuel cell powered automobiles," International Journal of Hydrogen Energy, 2001, pp. 381-397.

[74] B. Thorstensen, "A parametric study of fuel cell system efficiency under full and part load operation," Journal of Power Sources, vol. 92, 2001, pp. 9-16.

[75] S. Mcquire, Personal communication, Email: stuart.mcquire@bigpond.com.au, 2005.

[76] Ballard power, "Fuel cells," 2005, http://americanhistory.si.edu/fuelcells/pem/pem5.htm.

[77] B.Ridell, "Small scale fuel cell system in buildings, technical, environmental and economic aspects," Elforsk, 2003.

[78] L. Harnell, Personal communication, Email: lynndonh@ecn.net.au, 2005.

[79] P. Zwack, Environment and renewable resources Citypower, Personal communication, Email: Pzwack@citipower.com.au, 2005.

[80] J. Larmine, A. Dicks, "Fuel cell systems explained," John Wiley, Chichester, 2000.

[81] J. Edwards, T. Lipman, D. Kammen, "Fuel cell system economics: comparing the costs of generating power with stationary and motor vehicle PEM fuel cell systems," Energy Policy 2004, 2004, pp. 101-125.

[82] S. Aronsson, "Heat load of buildings supplied by district heating- an analysis based on measurements based in 50 buildings," Department of Building Services Engineering, 1996.

[83] A. Bejan, "Thermal design and optimization," 1996.

[84] N. Hino, T. Kato, "Economic assessment of home cogeneration sustem using PEFC taking into account fluctuating characteristics of hot water demand pattern," presented at ECOS 2003, Copenhagen, 2003.

[85] M. Risannen, S. Enback, C. Wallmark, P. Alvfors, G. Lindbergh, "Test facility for research on small scale stationary PEFC systems," KTH- Royal Institute of technology, Stockholm, 2002.

[86] J. Wimmer, D. Archer, "A phosphoric acid fuel cell cogeneration system retrofit to large office building," DOE/FETC-97/ 1044 (DE97005432), 1997.

[87] Vaillant, "Virtual power plant: Field tests with fuel cell heating appliances starts," 2004, www.vaillant.de.

[88] E. Gehain, L. Barrovecchio, "The fuel cell house of Gaz de France and H Power," The Fuel Cell Home, 2001, pp. 243-253.

[89] S. Sumi, H. Inka, "The development of of effective heat and power use technology for residential use in a PEFC cogeneration system," Journal of Power Sources, vol. 106, 2002, pp. 60-67.

[90] M.Ohlsson, "An investigation of the economy of fuel cells for distributed generation in Sweden," presented at 15th international conference on Efficiency, costs, optimization, simulation and environmental impact of energy systems, Berlin, 2002.

[91] J. Swisher, "Cleaner energy, greener profits: Fuel cells are cost effective distributed energy resources," Rocky Mountain Institute, 2002.

[92] G. Joy, D. Weinberg, F. Barbir, "Development of residential fuel cell power systems," presented at Fuel Cell seminar, 2000.

[93] R. Boersma, N. Sammes, "Small scale fuel cells for residential applications," Journal of power sources, 2000, pp. 98-110.

[94] T. Kerutz, J. Ogden, "Assessment of Hydrogen fuelled proton exchange membrane fuel cells for distributed generation and cogeneration," presented at 2000 USDOE Hydrogen Program Review, 2000.

[95] S. Ahmed, "Hydrogen from hydrocarbon fuels for fuel cells," *International Journal of Hydrogen energy*, 2001.

[96] U. Wagner, "Energy lifecycle analysis of hydrogen systems," International Journal of Hydrogen Energy, vol. 23, 1997, pp. 1-6.

[97] A. Lehmann, "Electricity and heat via natural gas reforming," University of Duisburg, Duisburg.

[98] P. Spath, "Life cycle assessment of hydrogen production via natural gas steam reforming," National Renewable Energy Laboratory, 2001.

[99] V. Scholz, R. Schmersahl, "Testing a PEM fuel cell System with biogas fuel," 2004, pp. 5-7.

APPENDIX

1] Some data of the reforming step for each of the different fuels used to produce Hydrogen

A] Natural gas

Of the different reforming processes mentioned in this study, steam reforming of NG is the one that is most developed and commercialized. In this study the steam reforming is chosen mainly due to the high Hydrogen yield that can be achieved. As this study uses stationary applications, there is a lower demand of a quick response time than it is for mobile applications.

Several articles present different empirical data and there is a problem of finding a reliable information about most of the reforming systems. Much articles present theoretical efficiency and those that are real efficiencies are not fully defined. The varied efficiencies from different gathered sources are:

Source [7]:

- Steam methane reforming (SMR) = 93.8 %, Auto thermal reforming (ATR) = 83.9 %

  Definition of efficiency: LHV of hydrogen consumed in FC/LHV of NG in (Hydrogen utilization in fuel cell = 80 %)

  These efficiencies are theoretical and are obtained through simulation. The efficiency is assumed independent of power and system size over a given turn down ratio (TDR), where TDR is defined as the ratio of maximum to minimum power.

Source [73]:

- SMR = 85.5 %

  Definition of efficiency: LHV of hydrogen out/LHV of NG in.

  The efficiency is based on own calculations where the LHV of NG in is used for all the necessary energy in the process. NG is assumed to contain pure methane.

Source [95]:

- Maximum theoretical efficiency = 93.9 %

  Definition of efficiency: LHV of hydrogen out/ LHV of methane in.

Source [96]:

- SMR = 70 %

  Definition of efficiency: LHV of hydrogen out [kWh]/LHV of NG in [kWh]

  The data is withdrawn from the figure where the indeed of NG is 1,428 kWh and the production flow of hydrogen is 1 kWh. This efficiency seems to be low. A possible explanation for this could be that the loss of energy is higher than it needs to be. Usually the heat from the reforming step can be used in the system.

Source [97]:

- SMR = 75 %

  Definition of efficiency: LHV of hydrogen out [kWh]/ (LHV of NG in [kWh] for reforming and the external burner). This efficiency is low and reason could be the same as in Wagner-source.

Source [98]:

- SR= 66 %

  Definition of efficiency : LHV of hydrogen out [kWh]/ LHV of NG in [kWh]

Economy

Some prices of reformers found in the different literature are shown below.

Source [7]:

- Fuel processor (\$) = 320 +36*$P_{FC\ max}$

  The price is given in \$ in 2003.

Source [97]:

- Estimated target cost = 250 \$/kW_{el}

B] Biogas

Biogas is upgraded before it is introduced to the fuel cell system and therefore is possible to use an ordinary natural gas reformer.

C] Methanol

Methanol is a little bit harder to reform as compared to natural gas but it is much easier to reform than is ethanol. Some of the gathered data about the efficiency of methanol reforming is shown below:

Source [73]:

- SR= 83.2 %

  Definition of efficiency: LHV of hydrogen out/ LHV of methanol in.

  This efficiency is based on own calculations where the LHV of methane in is used for all the necessary energy in the process.

Source [95]:

- Maximum theoretical efficiency = 96.3 %

  Definition of efficiency: LHV of hydrogen out/ LHV of methanol in.

Source [7]:

- SR = 77.5 %

  Definition of efficiency: HHV of hydrogen out/ HHV of methanol in.

  This efficiency is the parameter taken for all fuel cell applications.

Economy

A price of methanol reformer:

Source [7]:

Fuel processor = 15-25 $/ kWel. This is the target cost for vehicle applications.

D] Ethanol

Some data found about ethanol reforming:

Source [73]:

- SMR = 83.7 %

  Definition of efficiency: LHV of hydrogen out/ LHV of ethanol in.

  This efficiency is based on own calculations where the LHV of ethanol in is used for all the necessary energy processes.

Source [95]:

- Maximum theoretical efficiency = 93.7 %

  Definition of efficiency: LHV of hydrogen out/ LHV of ethanol in.

E] Diesel

Efficiency found on Diesel reforming:

Source [73]:

- SMR = 83.7 %

  Definition of efficiency: LHV of hydrogen out/ LHV of diesel in.

  This efficiency is based on own calculations where the LHV of diesel is under all the necessary energy in the process.

2] Equations used in calculations

5.5.1 Central architecture

A] Technical calculations

Demand approach 1:

In this case all the heat is supplied by the fuel cell system. This means that the fuel cell system must ensure that each building is supplied with 20500 kWh /year, even though there are heat losses on the way.

1. Distance from the fuel source to the central site:

d_{sc} = Input length 1 [m]

2. Distance from the central site to the building area:

d_{cb} = Input length 2 [m]

3. Length of fuel pipe:

$d_{fp} = d_{sc}$ [m]

4. Length of hydrogen pipe:

$d_{hp} = 0$ [m]

5. Length of heating pipes:

$d_{hep} = d_{cb}$ [m]

6. With a heat loss of 0.015 kW per meter heating pipe, this gives the total loss in the heat pipes [83]:

$q_{hep} = 0.015 * 8760 * d_{hep} = 131.4 * d_{hep}$ [kWth/year]

7. The total heat produced by the fuel cell system [82, 83]:

$q_{sys} = q_{demand} * N_b + 131.4 * d_{hep}$ [kWth/year]

8. The building heat demand [75]:

$q_{demand} = 5330$ [kWth/year/building]

9. Total fuel flow into the reformer [3, 99]:

$f_{ref} = q_{sys}/(\eta_{sys,tot} - \eta_{sys,el})$ [LHV kWhfuel/year]

10. Total power produced in the fuel cells [3, 99]:

$P_{FC} = f_{ref} * \eta_{sys,el}$ [kWhel/year]

11. Total fuel flow into the system [3]:

$F_{tot} = f_{ref}$ [LHV kWhfuel/year]

12. Maximum heat supplied by fuel cell system [75]:

$Q_{fc,max} = 5$ [kWth/ buliding]

13. The size of the fuel cell system [85]:

$P_{FC,max} = (Q_{FC,\ max}/(\eta_{sys,tot} - \eta_{sys,el})) * \eta_{sys,el} * N_b$ [kWel]

14. Power sold to the grid:

$P_{sold} = P_{FC} + P_{bought} - P_{demand}$ [kWhel/year]

15. Power bought from the grid [75]:

$P_{bought} = 304 * N_b$ [kWhel/year]

16. Total power demand [75]:

$P_{demand} = 1900 * N_b$ [kWhel/year]

Demand approach 2 – a 2 kW_{el} fuel cell system:

The requirements are that the fuel cell system must be able to supply continuously 2 kW_{el} continuously to the building. With a 2 kW_{el} fuel cell system a larger part of power would be bought from the power grid than in the first demand approach and a part of heat demand supplied by additional heating.

1. With a heat loss of 0.015 kW per meter heating pipe, this gives the total loss in the heat pipes [83]:

$q_{hep} = 0.015 * 8760 * d_{hep} = 131.4 * d_{hep}$ [kW_{th}/year]

2. The total heat produced by the fuel cell system. The burner takes care of the additional heat q_b needed [82, 83]:

$q_{sys} = (q_{demand}-q_b) * N_b + 131.4 * d_{hep}$ [kW_{th}/year]

3. The building heat demand [75]:

$q_{demand} = 5330$ [kW_{th}/year/building]

4. Additional heat supplied by the burner [3, 75]:

$q_b = 1066$ [kW_{th}/year/building]

5. Total fuel flow into the reformer [3, 99]:

$f_{ref} = q_{sys}/(\eta_{sys,tot} - \eta_{sys,el})$ [LHV kWh_{fuel}/year]

6. Total power produced in the fuel cells [3, 99]:

$P_{FC} = f_{ref} * \eta_{sys,el}$ [kWh_{el}/year]

7. Fuel flow into the burners [3]:

$F_b = (q_b/\eta_b) * N_b$ [LHV kWh_{fuel}/year]

8. Total fuel flow into the system [3]:

$f_{tot} = f_{ref} + F_b$ [LHV kWh_{fuel}/year]

9. The size of the fuel cell system:

$P_{FC,max} = 2 * N_b$ [kWel]

10. Power sold to the grid:

$P_{sold} = P_{FC} + P_{bought} - P_{demand}$ [kWhel/year]

11. Power bought from the grid [75]:

$P_{bought} = 513 * N_b$ [kWhel/year]

12. The total power demand [75]:

$P_{demand} = 1900 * N_b$ [kWhel/year]

B] Economic calculations:

The economic calculations are the same for both the demand approaches.

1. Cost of the fuel pipeline:

$C_{fp} = d_{fp} * PR_{fp}$ [$]

2. Cost of heat pipeline:

$C_{hep} = d_{hep} * PR_{hep}$ [$]

3. Cost of hydrogen pipeline (= 0):

$C_{hp} = d_{hp} * PR_{hp}$ [$]

4. Total pipeline cost [82]:

$TC_{pipe} = C_{fp} + C_{hep} + C_{hp}$ [$]

5. Capital cost of the pipelines [82]:

$CC_{pipe} = TC_{pipe} * a_d$ [$/year]

6. Distribution system annuity factor[82]:

$a_d = [I/100] / [1 - (1 + I/100) \text{ EXP } -D_d]$

7. Intereast rate [90]:

I = 8 [%]

8. Pipeline depreciation time [2, 82]:

$D_d = 40$ [years]

9. System cost [10, 94]:

Total fuel cell system cost = $PR_{kW} * PFC_{max} * N_b$ [$]

OR

Total cost for all the fuel cell system = 1500. ($P_{FC, comp}$/1) EXP 0.8 + $N_{FC, 250}$ * (1500 * (250/1) EXP 0.8) [$]

10. Cost for building and help equipment [92]:

$C_{be} = 0.10 * C_{sys}$ [$]

11. Cost for land improvement [92]:

$C_1 = 0.10 * C_{sys}$ [$]

12. Total system cost [92]:

$TC_{sys} = C_{sys} + C_{be} + C_1$ [$]

13. Capital cost of system [82, 94]:

$CC_{sys} = TC_{sys} * a_s$ [$/year]

14. System annuity factor [82, 94]:

a_s = [I/100]/ [1 - (1 + I/100) EXP $-D_s$]

15. System depreciation time (Standard case) [2]:

$D_s = 20$ [years]

Variable costs:

16. Cost of sold power to the grid (negative):

$C_{el,sell} = -P_{sold} * PR_{el,sell}$ [$/year]

17. Cost of bought power from the grid:

$C_{el,bought} = P_{bought} * PR_{el,bought}$ [$/year]

18. Cost of bought fuel:

$C_{fuel} = F_{tot} * PR_{fuel}$ [$/year]

19. Maintenance cost of pipeline:

$OM_{pipe} = 0$ [$/year]

20. Maintenance cost of the fuel cell (cost approach 2) [10, 81, 94]:

$OM_{FC} = 15/20 * ((1073 + 22 * P_{FC,comp})/ (2233 + 155 * P_{FC,comp}) * (P_{kW} * (P_{FC,comp}/1) \wedge (0.8)) + (1073 + 22 * 250)/ (2233 + 155 * 250) * N_{FC,250} * (P_{kW} * (250/1) \wedge (0.8))) * a_{FC}$ [$/year]

The operation and maintenance cost of the fuel cell is required to be 15 years because the newly installed fuel cell stacks last for 5 years.

22. Maintenance cost of the fuel cell (Cost approach 1) [81, 90]:

$OM_{FC} = 1/3 * 15/20 * C_{sys} * a_{FC}$ [$/year]

The fuel cell component cost is assumed to be 1/3 of the total fuel cell system cost.

23. Maintenance cost of the complete system [90]:

$OM_{sys} = 0.10 * TC_{sys}$ [$/year]

24. Unforseen expenses [90]:

$UE = 0.10 * TC_{sys}$ [$/year]

25. Fuel tax deduction (negative) [77]:

$TD = - (ET * f_{ref} * 0.5 * (\eta_{sys,tot} - \eta_{sys,el}) + (ET + CT) * f_{ref} * \eta_{sys,el})$ [$/year]

26. Total variable cost [2]:

$TVC = CC_{pipe} + C_{el,sell} + C_{el,bought} + C_{fuel} + OM_{pipe} + OM_{FC} + OM_{sys} + UE + TD$ [$/year]

27. Total cost of the complete system [2]: [$/year]

$TC_{TOT} = CC_{sys} + TVC$

28. Total cost of complete system per building [2]:

$TC_{TOT,b} = TC_{TOT}/N_b$ [$/year/building]

5.5.2 Split architecture

A] Technical calculations

Demand approach 1

In this case all the heat is supplied by the fuel cell system. The heat is produced in the building.

1. Distance from the fuel source to the central site:

d_{sc} = Input length 1 [m]

2. Distance from the central site to the building area:

d_{cb} = Input length 2 [m]

3. Length of fuel pipe:

$d_{fp} = d_{sc}$ [m]

4. Length of hydrogen pipe:

$d_{hp} = d_{cb}$ [m]

5. Length of heating pipes:

$d_{hep} = 0$

6. The total heat produced by the fuel cell system:

$q_{sys} = q_{demand} * N_b$ [kW_{th}/year]

7. The building heat demand [75]:

$q_{demand} = 5330$ [kW_{th}/year/building]

8. Total fuel flow into the reformer [3, 99]:

$f_{ref} = q_{sys}/(\eta_{sys,tot} - \eta_{sys,el})$ [LHV kWh_{fuel}/year]

9. Total power produced in each fuel cell [3, 99]:

$P_{FC} = (q_{demand}/(\eta_{sys,tot} - \eta_{sys,el})) * \eta_{sys,el}$ [kWh_{el}/year]

10. Total fuel flow into the system [3]:

$F_{tot} = f_{ref}$ [LHV kWh_{fuel}/year]

11. Maximum heat supplied by fuel cell system [75]:

$Q_{fc,max} = 5$ [kW_{th}/ buliding]

12. The size of the fuel cell system [85]:

$P_{FC,max} = (Q_{FC,\ max}/(\ \eta_{sys,tot} - \eta_{sys,el})) * \eta_{sys,el}$ [kWel]

13. Power sold to the grid:

$P_{sold} = P_{FC} * N_b + P_{bought} - P_{demand}$ [kWhel/year]

14. Power bought from the grid [75]:

$P_{bought} = 304 * N_b$ [kWhel/year]

15. Total power demand [75]:

$P_{demand} = 1900 * N_b$ [kWhel/year]

Demand approach 2 – a 2 kWel fuel cell system

The requirements are that the fuel cell system must be able to supply continuously 2 kWel continiously to the building. With a 2 kWel fuel cell system a larger part of power would be bought from the power grid than in the first demand approach and a part of heat demand supplied by additional heating.

1. The total heat produced by the fuel cell system. The burner takes care of the additional heat q_b needed [82, 83]:

$q_{sys} = (q_{demand} - q_b) * N_b$ [kWth/year]

2. The building heat demand [3, 75]:

$q_{demand} = 5330$ [kWth/year/building]

3. Additional heat supplied by the burner [3, 75]:

$q_b = 1066$ [kWth/year/building]

4. Total fuel flow into the reformer [3]:

$f_{ref} = q_{sys}/(\eta_{sys,tot} - \eta_{sys,el}) + N_b * q_b/(\eta_b * \eta_{ref})$ [LHV kWhfuel/year]

5. Total power produced in each fuel cell [3]:

$P_{FC} = ((q_{demand} - q_b)/(\eta_{sys,tot} - \eta_{sys,el})) * \eta_{sys,el}$ [kWhel/year]

6. Fuel flow into the burners [3]:

$F_b = (q_b/\eta_b) * N_b$ [LHV kWh_{fuel}/year]

7. Total fuel flow into the system [3]:

$f_{tot} = f_{ref} + F_b$ [LHV kWh_{fuel}/year]

8. The size of the fuel cell system:

9. $P_{FC,max} = 2$ [kW_{el}]

10. Power sold to the grid [75]:

$P_{sold} = P_{FC} * N_b + P_{bought} - P_{demand}$ [kWh_{el}/year]

11. Power bought from the grid [75]:

$P_{bought} = 513 * N_b$ [kWh_{el}/year]

12. The total power demand [75]:

$P_{demand} = 1900 * N_b$ [kWh_{el}/year]

B] Economic calculations

The economic calculations are the same for both the demand approaches.

1. Cost of the fuel pipeline:

$C_{fp} = d_{fp} * PR_{fp}$ [\$]

2. Cost of heat pipeline:

$C_{hep} = d_{hep} * PR_{hep}$ [\$]

3. Cost of hydrogen pipeline (= 0):

$C_{hp} = d_{hp} * PR_{hp}$ [\$]

4. Total pipeline cost:

$TC_{pipe} = C_{fp} + C_{hep} + C_{hp}$ [\$]

5. Capital cost of the pipelines:

$CC_{pipe} = TC_{pipe} * a_d$ [\$/year]

6. Distribution system annuity factor [82]:

$ad = [I/100]/ [1 - (1 + I/100) EXP -Dd]$

7. Intereast rate [90]:

$I = 8$ [%]

8. Pipeline depreciation time [82]:

$Dd = 40$ [years]

9. System cost [2, 82]:

Total fuel cell system cost = $PR_{kW} . PFC_{max} . N_b$ [$]

OR

The total cost for all the fuel cell systems = $N_b * (1500 * ((P_{FC, split} / 1) ^{\wedge} 0.8) * (A_{FC*} + 0.5\ A_{elec*})) + 1500 * (P_{FC, split}. N_b/1)\ EXP\ 0.8) * (A_{REF} + 0.5\ A_{elec})$ [$]

10. Cost for building and help equipment [92]:

$C_{be} = 0.10 * C_{sys}$ [$]

11. Cost for land improvement [92]:

$C_1 = 0.10 * C_{sys}$ [$]

12. Total system cost [92]:

$TC_{sys} = C_{sys} + C_{be} + C_1$ [$]

13. Capital cost of system [94]:

$CC_{sys} = TC_{sys} * a_s$ [$/year]

14. System annuity factor [94]:

$a_s = [I/100]/ [1 - (1 + I/100) EXP -D_s]$

15. System depreciation time (Standard case) [2]:

$D_s = 20$ [years]

Variable costs

16. Cost of sold power to the grid (negative):

$C_{el,sell} = -P_{sold} * PR_{el.sell}$ [$/year]

17. Cost of bought power from the grid:

$C_{el,bought} = P_{bought} * PR_{el,bought}$ [$/year]

18. Cost of bought fuel:

$C_{fuel} = F_{tot} * PR_{fuel}$ [$/year]

19. Maintenance cost of pipeline:

$OM_{pipe} = 0$ [$/year]

20. Maintenance cost of the fuel cell (cost approach 2) [81, 92, 94]:

$OM_{FC} = 15/20 * (N_b * (1073 + 22 * P_{FC,max})/ (2233 + 155 * P_{FC,max}) * P_{kW} * ((P_{FC,max}/1) \wedge (0.8))) a_{FC}$ [$/year]

The operation and maintenance cost of the fuel cell is required to be 15 years because the newly installed fuel cell stacks last for 5 years.

21. Maintenance cost of the fuel cell (Cost approach 1) [81, 90]:

$OM_{FC} = 1/3 * 15/20 * C_{sys} * a_{FC}$ [$/year]

The fuel cell component cost is assumed to be 1/3 of the total fuel cell system cost.

22. Maintenance cost of the complete system [90]:

$OM_{sys} = 0.10 * TC_{sys}$ [$/year]

23. Unforseen expenses [90]:

$UE = 0.10 * TC_{sys}$ [$/year]

24. Fuel tax deduction (negative) [77]:

$TD = -(f_{tot} - (q_{demand}/(\eta_b * \eta_{ref}))) * (ET * 0.5 * (\eta_{sys,tot} - \eta_{sys,el}) + (CT + ET) * \eta_{sysel})$ [$/year]

25. Total variable cost [2]:

$TVC = CC_{pipe} + C_{el,sell} + C_{el,bought} + C_{fuel} + OM_{pipe} + OM_{FC} + OM_{sys} + UE + TD$ [$/year]

26. Total cost of the complete system [2]:

$TC_{TOT} = CC_{sys} + TVC$ [$/year]

27. Total cost of complete system per building:

$TC_{TOT,b} = TC_{TOT}/N_b$ [$/year/building]

5.5.3 Local architecture

A] Technical calculations

Demand approach 1

In this case all the heat is supplied by the fuel cell system. The heat is produced in the building.

1. Distance from the fuel source to the central site:

d_{sc} = Input length 1 [m]

2. Distance from the central site to the building area:

d_{cb} = Input length 2 [m]

3. Length of fuel pipe:

$d_{fp} = d_{sc} + d_{cb}$ [m]

4. Length of hydrogen pipe:

$d_{hp} = 0$ [m]

5. Length of heating pipes:

$d_{hep} = 0$

6. The total heat produced by the fuel cell system:

$q_{sys} = q_{demand}$ [kWth/year]

7. The building heat demand [75]:

$q_{demand} = 5330$ [kWth/year/building]

8. Total fuel flow into the reformer [3]:

$f_{ref} = f_{ref} * \eta_{sys,el}$ [LHV kWhfuel/year]

9. The size of the fuel cell [3]:

$P_{FC} = (Q_{FC,max}/(\eta_{sys,tot} - \eta_{sys,el})) * \eta_{sys,el}$ [kWhel/year]

10. Total fuel flow into the system [3]:

$F_{tot} = f_{ref} * N_b$ [LHV kWh_{fuel}/year]

11. Maximum heat supplied by fuel cell system [75]:

$Q_{fc,max} = 5$ [kWth/ buliding]

12. The size of the fuel cell system [85]:

$P_{FC,max} = (Q_{FC,\ max}/(\eta_{sys,tot} - \eta_{sys,el})) * \eta_{sys,el}$ [kW_{el}]

13. Power sold to the grid:

$P_{sold} = P_{FC} * N_b + P_{bought} - P_{demand}$ [kWhel/year]

14. Power bought from the grid [75]:

$P_{bought} = 304 * N_b$ [kWh_{el}/year]

15. Total power demand [75]:

$P_{demand} = 1900 * N_b$ [kWhel/year]

Demand approach 2 – a 2 kW_{el} fuel cell system

The requirements are that the fuel cell system must be able to supply continuously 2 kW_{el} continiously to the building. With a 2 kW_{el} fuel cell system a larger part of power would be bought from the power grid than in the first demand approach and a part of heat demand supplied by additional heating.

1. The total heat produced by the fuel cell system. The burner takes care of the additional heat qb needed [82, 83]:

$q_{sys} = (q_{demand}-q_b) * N_b$ [kWth/year]

2. The building heat demand [75]:

$q_{demand} = 5330$ [kW_{th}/year/building]

3. Additional heat supplied by the burner [3, 75]:

$q_b = 1066$ [kW_{th}/year/building]

4. Total fuel flow into the reformer [3]:

$f_{ref} = q_{sys}/(\eta_{sys,tot} - \eta_{sys,el})$ [LHV kWh_{fuel}/year]

5. Total power produced in each fuel cell [3]:

$P_{FC} = ((q_{demand} - q_b)/(\eta_{sys,tot} - \eta_{sys,el})) * \eta_{sys,el}$ [kWhel/year]

6. Fuel flow into the burners [3]:

$F_b = (q_b/\eta_b) * N_b$ [LHV kWhfuel/year]

7. Total fuel flow into the system [3]:

$f_{tot} = f_{ref} + f_b$ [LHV kWhfuel/year]

8. The size of the fuel cell system:

$P_{FC,max} = 2$ [kWel]

9. Power sold to the grid [75]:

$P_{sold} = P_{FC} * N_b + P_{bought} - P_{demand}$ [kWhel/year]

10. Power bought from the grid [75]:

$P_{bought} = 513 * N_b$ [kWhel/year]

11. The total power demand [75]:

$P_{demand} = 1900 * N_b$ [kWhel/year]

B] Economic calculations

The economic calculations are the same for both the demand approaches.

1. Cost of the fuel pipeline:

$C_{fp} = d_{fp} * PR_{fp}$ [$]

2. Cost of heat pipeline:

$C_{hep} = d_{hep} * PR_{hep}$ [$]

3. Cost of hydrogen pipeline (= 0):

$C_{hp} = d_{hp} * PR_{hp}$ [$]

4. Total pipeline cost:

$TC_{pipe} = C_{fp} + C_{hep} + C_{hp}$ [$]

5. Capital cost of the pipelines [82]:

$CC_{pipe} = TC_{pipe} * a_d$ [$/year]

6. Distribution system annuity factor [82]:

$a_d = [I/100]/ [1 - (1 + I/100) EXP -D_d]$

7. Intereast rate [82, 90]:

I = 8 [%]

8. Pipeline depreciation time [2, 82]:

$D_d = 40$ [years]

9. System cost [92, 94]:

Total fuel cell system cost = $PR_{kW} * P_{FCmax} * N_b$ [$]

OR

The total cost for all the fuel cell systems = 1500 * ((PFClocal/1) ^ 0.8) * Nb [$]

10. Cost for building and help equipment [92]:

$C_{be} = 0.05 * C_{sys}$ [$]

11. Cost for land improvement [92]:

$C_l = 0 * C_{sys}$ [$]

12. Total system cost [92]:

$TC_{sys} = C_{sys} + C_{be} + C_l$ [$]

13. Capital cost of system [82, 94]:

$CC_{sys} = TC_{sys} * a_s$ [$/year]

14. System annuity factor [82, 94]:

$a_s = [I/100]/ [1 - (1 + I/100) EXP -D_s]$

15. System depreciation time (Standard case) [2]:

$D_s = 20$ [years]

Variable costs

16. Cost of sold power to the grid (negative):

$C_{el,sell} = -P_{sold} * PR_{el.sell}$ [$/year]

17. Cost of bought power from the grid:

$C_{el,bought} = P_{bought} * PR_{el,bought}$ [$/year]

18. Cost of bought fuel:

$C_{fuel} = F_{tot} * PR_{fuel}$ [$/year]

19. Maintenance cost of pipeline:

$OM_{pipe} = 0$ [$/year]

20. Maintenance cost of the fuel cell (cost approach 2) [81, 92, 94]:

$OM_{FC} = 15/20 * (N_b * (1073 + 22 * P_{FC,max})/ (2233 + 155 * P_{FC,max}) * P_{kW} * ((P_{FC,max}/1) \wedge (0.8))) a_{FC}$ [$/year]

The operation and maintenance cost of the fuel cell is required to be 15 years because the newly installed fuel cell stacks last for 5 years.

21. Maintenance cost of the fuel cell (Cost approach 1) [81, 82, 90]:

$OM_{FC} = 1/3 * 15/20 * C_{sys} * a_{FC}$ [$/year]

The fuel cell component cost is assumed to be 1/3 of the total fuel cell system cost.

22. Maintenance cost of the complete system [82, 90]:

$OM_{sys} = 0.10 * TC_{sys}$ [$/year]

23. Unforseen expenses [90]:

$UE = 0.10 * TC_{sys}$ [$/year]

24. Fuel tax deduction (negative) [77]:

$TD = -(ET * f_{ref} * 0.5 * (\eta_{sys,tot} - \eta_{sys,el}) + (ET + CT) * f_{ref} * \eta_{sys,el})$ [$/year]

25. Total variable cost [2]:

$TVC = CC_{pipe} + C_{el,sell} + C_{el,bought} + C_{fuel} + OM_{pipe} + OM_{FC} + OM_{sys} + UE + TD$ [$/year]

26. Total cost of the complete system:

$TC_{TOT} = CC_{sys} + TVC$ [$/year]

27. Total cost of complete system per building:

$TC_{TOT,b} = TC_{TOT}/N_b$ [$/year/building]

3] A. *Full heat supply strategy linear approach*

In and result data

In

Distance between the fuel source and a central system location	1000 [m]
Distance between a central system location and the building area	500 [m]
Type of demand supply, 1 = All heat, 2 = 2 kWel	1

Result

Total cost [$/year]	Central	Split	Local	Reference
Natural gas	194,365	235,014	140,097	59,854

Cost per building [$/year]	Central	Split	Local	Reference
Natural gas	1,944	2,350	1,401	599

About the program

The main objective with the program is to calculate the costs for three different configurations of fuel cell systems, see configuration sheet.
Chose the type of heat demand approach in this sheet.
Chose the distances in this sheet.
Parameters for the chosen fuel can be changed in the fuel sheet.
General parameters that apply for all fuels can be changed in the demand and standard values sheet.
The results for the chosen parameter values are given in the In and result data sheet.
The impact of different parameters can be studied in the variation sheet.
The variation of other parameters can be done with VBA in the variation sheet.

Attention!
When the indata is altered in this sheet, the variation sheet should be reset.
If the reset button is not pushed the variation sheet will show old results.

Reset variation sheet

Push the button and the cells returns to their standard values

Standard values

Standard values

Push the button and the cells returns to their standard values

Demand of buildings

Yearly heat demand	5,330	[kWh/year]
Yearly power demand	1,900	[kWh/year]

1. All heat supplied by fuel cell

Data

Power bought from the grid	304	[kWh/year]
Additional heat required	0	[kWh/year]
Fuel cell size	2.69	[kWel]
Fuel cell maximum heat suppy	5	[kWth]

2. A 2 kWel fuel cell system

Data

Power bought from the grid	513	[kWh/year]
Additional heat required	1066	[kWh/year]
Fuel cell size	2	[kWth]

General constants and figures

Economy parameters

Price of power	0.13	[$/kWh]
Goverment support for sold power	0.02	[$/kWh]
Total price for sold power	0.15	[$/kWh]
Power tax	0.015	[$/kWh]
Price for grid connection	0.02	[$/kWh]
Total cost of power for customer	0.165	$/kWh]
Hydrogen pipeline	665	[$/m]
District heat pipeline	425	[$/m]
Interest rate	8	[%]
System deprecation time	20	[Year]
Distribution system deprecation time	40	[Year]
Annuity factor for system	0.101852209	
Annuity factor for distribution components	0.083860162	
Annuity factor for fuel cell	0.250456455	
Exchange rate, 1US$ in AU$	1.4	
Price of fuel cell system	2,100	[$/kW]
Scale factor for fuel cell system	1	
Price of fuel cell system	1500	[US$/kW]
Annuity factor for burner	0.101852209	

Conditions

Average heat demand	5330	[kWh/building,year]
Average power demand	1900	[kWh/building,year]
Bought power from the grid	304	[kWh/year]
Total bought power from the grid	30400	[kWh/year]
Additional heat needed	0	[kWh/year]
Number of buildings	100	
Hours of a year	8760	[Hours]

Constants

LHV hydrogen	2.8	[kWh/Nm3]
Hydrogen density	0.084	[kg/Nm3]

Attention!

When the indata is altered in this sheet, the variation sheet should be reset.
If the reset button is not pushed the variation sheet will show old results.
Do not change the position of the parameters in this sheet. It will cause faults in the VBA-program where a specific parameter relates to a specific cell.

Reset variation sheet

Natural gas

System efficiencies	Central	Split	Local	
System power efficiency	0.35	0.35	0.35	
Total system efficiency	0.85	0.75	1.00	
Burner efficiency	0.94	0.94	0.94	
Reformer efficiency		0.90		

Technical calculation	Central	Split	Local	
Total loss of heat in pipes	65,700	-	-	[kWh/year]
Total produced heat by system	598,700	533,000	533,000	[kWh/year]
Total fuel flow into reformers	1,197,400	1,332,500	8,200	[kWh/year]
Produced power in each fuel cell	419,090	4,664	2,870	[kWh/year]
Total produced power	419,090	466,375	287,000	[kWh/year]
Total fuel need	1,197,400	1,332,500	820,000	[kWh/year]
Fuel cell size requirement	350.0	4.38	2.69	[kWel]
Number of 250 kW fuel cells	1	0	0	
Size of complementing fuel cell	100	4.4	2.7	[kWel]
Power sold to the grid	259,490	306,775	127,400	[kWh/year]

Economic calculations

Distribution components	Central	Split	Local	
Fuel pipeline	105,000	105,000	157,500	[$]
Hydrogen pipeline	-	332,500	-	[$]
District heating pipeline	212,500	-	-	[$]
Total pipeline cost	317,500	437,500	157,500	[$]
Capital cost of pipelines	26,626	36,689	13,208	[$/year]

Total system cost	Central	Split	Local	
Fuel cell system	735,000	918,750	565,385	[$]
Burner	-	-	-	[$]
System cost	735,000	918,750	565,385	[$]
Buildings and help equipment	73,500	91,875	28,269	[$]
Improvment of land	73,500	45,938	-	[$]
Total system cost	882,000	1,056,563	593,654	[$]
Capital cost of system	89,834	107613	60465	[$/year]

Variable costs	Central	Split	Local	
Distribution system	26,626	36,689	13,208	[$/year]
O&M distribution	-	-	-	[$/year]
Power sold to the grid	- 38,924	- 46,016	- 19,110	[$/year]
Power bought from the grid	3,952	3,952	3,952	[$/year]
Fuel	35,922	39,975	24,600	[$/year]
O&M system	8,983	10,761	6,046	[$/year]
O&M fuel cell	45,937	57,421	35,336	[$/year]
Unforseen expenses	8,983	10,761	6,046	[$/year]
Tax deduction	13,052	13,858	9,553	[$/year]
Total variable cost	104,531	127,401	79,632	[$/year]

	Central	Split	Local	
Total cost	194,365	235,014	140,097	[$/year]
Total cost per building	1,944	2,350	1,401	[$/year]

Constants

LHV fuel	11.2	[kWh/Nm3]
Fuel density	0.85	[kg/Nm3]

Economy parameters

Fuel	0.03	[$/kWhfuel]
Energy tax fuel	0.01	[$/kWhfuel]
Carbon dioxide tax	0.01	[$/kWhfuel]
Fuel pipeline	105	[$/m]
Transport by truck		[$/m]
Amount of fuel per truck		[kWh/truck]

Reference case

Technical calculation		
Bought power from the grid	1,900	[kWh/building,year]
Total bought power from the grid	190,000	[kWh/year]
Produced heat by burner	5,330	[kWh/building,year]
Total produced heat by burners	533,000	[kWh/year]
Total amount of fuel used in burners	567,021	[kWh/year]

Economical calculation		
Total burner price	32,500	[$]
Fuel pipeline	157,500	[$]
Capital cost pipeline	13,208	[$/year]
Capital cost burners	3,310.20	[$/year]
O&M cost burners	1,625	[$/year]
Price of total bought power	24,700	[$/year]
Price of fuel	17,011	[$/year]
Total cost	59,854	[$/year]
Total cost per building	599	[$/year]

Attention!

When the indata is altered in this sheet, the variation sheet should be reset. If the reset button is not pushed the variation sheet will show old results. Do not change the position of the parameters in this sheet. It will cause faults in the VBA-program where a specific parameter relates to a specific cell.

Reset variation sheet

Push the button and the cells returns to their standard values

Standard values

3] B. *Partial* heat supply strategy *linear* approach

In and result data

In

Distance between the fuel source and a central system location	1000	[m]
Distance between a central system location and the building area	500	[m]
Type of demand supply, 1 = All heat, 2 = 2 kWel	2	

Result

Total cost [$/year]	Central	Split	Local	Reference
Natural gas	134,091	148,853	123,319	59,854

Cost per building [$/year]	Central	Split	Local	Reference
Natural gas	1,341	1,489	1,233	599

About the program

The main objective with the program is to calculate the costs for three different configurations of fuel cell systems, see configuration sheet.
Chose the type of heat demand approach in this sheet.
Chose the distances in this sheet.
Parameters for the chosen fuel can be changed in the fuel sheet.
General parameters that apply for all fuels can be changed in the demand and standard values sheet.
The results for the chosen parameter values are given in the In and result data sheet.
The impact of different parameters can be studied in the variation sheet.
The variation of other parameters can be done with VBA in the variation sheet.

Attention!
When the indata is altered in this sheet, the variation sheet should be reset.
If the reset button is not pushed the variation sheet will show old results.

Reset variation sheet

Push the button and the cells returns to their standard values

Standard values

Demand of buildings

Yearly heat demand	5,330	[kWh/year]
Yearly power demand	1,900	[kWh/year]

Standard values

Push the button and the cells returns to their standard values

1. All heat supplied by fuel cell

Data		
Power bought from the grid	304	[kWh/year]
Additional heat required	0	[kWh/year]
Fuel cell size	2.69	[kWel]
Fuel cell maximum heat suppy	5	[kWth]

2. A 2 kWel fuel cell system

Data		
Power bought from the grid	513	[kWh/year]
Additional heat required	1066	[kWh/year]
Fuel cell size	2	[kWth]

General constants and figures

<u>Economy parameters</u>

Price of power	0.13	[$/kWh]
Goverment support for sold power	0.02	[$/kWh]
Total price for sold power	0.15	[$/kWh]
Power tax	0.015	[$/kWh]
Price for grid connection	0.02	[$/kWh]
Total cost of power for customer	0.165	$/kWh]
Hydrogen pipeline	680	[$/m]
District heat pipeline	425	[$/m]
Interest rate	8	[%]
System deprecation time	20	[Year]
Distribution system deprecation time	40	[Year]
Annuity factor for system	0.101852209	
Annuity factor for distribution components	0.083860162	
Annuity factor for fuel cell	0.250456455	
Exchange rate, 1US$ in AU$	1.4	
Price of fuel cell system	2,100	[$/kW]
Scale factor for fuel cell system	1	
Price of fuel cell system	1500	[US$/kW]
Annuity factor for burner	0.101852209	

<u>Conditions</u>

Average heat demand	5330	[kWh/building,year]
Average power demand	1900	[kWh/building,year]
Bought power from the grid	513	[kWh/year]
Total bought power from the grid	51300	[kWh/year]
Additional heat needed	1066	[kWh/year]
Number of buildings	100	
Hours of a year	8760	[Hours]

<u>Constants</u>

LHV hydrogen	2.8	[kWh/Nm3]
Hydrogen density	0.084	[kg/Nm3]

Attention!

When the indata is altered in this sheet, the variation sheet should be reset.
If the reset button is not pushed the variation sheet will show old results.
Do not change the position of the parameters in this sheet. It will cause faults in the VBA-program where a specific parameter relates to a specific cell.

Reset variation sheet

Natural gas

System efficiencies	Central	Split	Local
System power efficiency	0.35	0.35	0.35
Total system efficiency	0.85	0.75	1.00
Burner efficiency	0.94	0.94	0.94
Reformer efficiency		0.90	

Technical calculation	Central	Split	Local	
Total loss of heat in pipes	65,700	-	-	[kWh/year]
Total produced heat by system	492,100	426,400	426,400	[kWh/year]
Total fuel flow into reformers	984,200	1,192,005	6,560	[kWh/year]
Produced power in each fuel cell	344,470	3,731	2,296	[kWh/year]
Total produced power	344,470	373,100	229,600	[kWh/year]
Total fuel need	1,097,604	1,192,005	769,404	[kWh/year]
Fuel cell size requirement	200.0	2.00	2.00	[kWel]
Number of 250 kW fuel cells	0	0	0	
Size of complementing fuel cell	200	2.0	2.0	[kWel]
Power sold to the grid	205,770	234,400	90,900	[kWh/year]

Economic calculations

Distribution components	Central	Split	Local	
Fuel pipeline	105,000	105,000	157,500	[$]
Hydrogen pipeline	-	340,000	-	[$]
District heating pipeline	212,500	-	-	[$]
Total pipeline cost	317,500	445,000	157,500	[$]
Capital cost of pipelines	26,626	37,318	13,208	[$/year]

Total system cost	Central	Split	Local	
Fuel cell system	420,000	420,000	420,000	[$]
Burner	750	32,500	32,500	[$]
System cost	420,750	452,500	452,500	[$]
Buildings and help equipment	42,075	45,250	22,625	[$]
Improvment of land	42,075	22,625	-	[$]
Total system cost	504,900	520,375	475,125	[$]
Capital cost of system	51,425	53001	48393	[$/year]

Variable costs				
Distribution system	26,626	37,318	13,208	[$/year]
O&M distribution	-	-	-	[$/year]
Power sold to the grid	- 30,866	- 35,160	- 13,635	[$/year]
Power bought from the grid	6,669	6,669	6,669	[$/year]
Fuel	32,928	35,760	23,082	[$/year]
O&M system	5,143	5,300	4,839	[$/year]
O&M fuel cell	26,296	28,281	28,281	[$/year]
Unforseen expenses	5,143	5,300	4,839	[$/year]
Tax deduction	10,728	12,384	7,642	[$/year]
Total variable cost	82,666	95,852	74,926	[$/year]

	Central	Split	Local	
Total cost	134,091	148,853	123,319	[$/year]
Total cost per building	1,341	1,489	1,233	[$/year]

Constants

LHV fuel	11.2	[kWh/Nm3]
Fuel density	0.85	[kg/Nm3]

Economy parameters

Fuel	0.03	[$/kWhfuel]
Energy tax fuel	0.01	[$/kWhfuel]
Carbon dioxide tax	0.01	[$/kWhfuel]
Fuel pipeline	105	[$/m]
Transport by truck		[$/m]
Amount of fuel per truck		[kWh/truck]

Reference case

Technical calculation		
Bought power from the grid	1,900	[kWh/building,year]
Total bought power from the grid	190,000	[kWh/year]
Produced heat by burner	5,330	[kWh/building,year]
Total produced heat by burners	533,000	[kWh/year]
Total amount of fuel used in burners	567,021	[kWh/year]

Economical calculation		
Total burner price	32,500	[$]
Fuel pipeline	157,500	[$]
Capital cost pipeline	13,208	[$/year]
Capital cost burners	3,310.20	[$/year]
O&M cost burners	1,625	[$/year]
Price of total bought power	24,700	[$/year]
Price of fuel	17,011	[$/year]
Total cost	59,854	[$/year]
Total cost per building	599	[$/year]

Attention!

When the indata is altered in this sheet, the variation sheet should be reset.
If the reset button is not pushed the variation sheet will show old results.
Do not change the position of the parameters in this sheet. It will cause faults in the VBA-program where a specific parameter relates to a specific cell.

Reset variation sheet

Push the button and the cells returns to their standard values

Standard values

3] C. Full heat supply strategy acaling factor approach

In and result data

In

Distance between the fuel source and a central system location	1000 [m]
Distance between a central system location and the building area	500 [m]
Type of demand supply, 1 = All heat, 2 = 2 kWel	1

Result

Total cost [$/year]	Central	Split	Local	Reference
Natural gas	90,919	155,953	118,249	59,854

Cost per building [$/year]	Central	Split	Local	Reference
Natural gas	909	1,560	1,182	599

About the program

The main objective with the program is to calculate the costs for three different configurations of fuel cell systems, see configuration sheet.
Chose the type of heat demand approach in this sheet.
Chose the distances in this sheet.
Parameters for the chosen fuel can be changed in the fuel sheet.
General parameters that apply for all fuels can be changed in the demand and standard values sheet.
The results for the chosen parameter values are given in the In and result data sheet.
The impact of different parameters can be studied in the variation sheet.
The variation of other parameters can be done with VBA in the variation sheet.

Attention!
When the indata is altered in this sheet, the variation sheet should be reset.
If the reset button is not pushed the variation sheet will show old results.

Reset variation sheet

Push the button and the cells returns to their standard values

Standard values

Standard values

Push the button and the cells returns to their standard values

Demand of buildings

Yearly heat demand	5,330	[kWh/year]
Yearly power demand	1,900	[kWh/year]

1. All heat supplied by fuel cell

Data		
Power bought from the grid	304	[kWh/year]
Additional heat required	0	[kWh/year]
Fuel cell size	2.69	[kWel]
Fuel cell maximum heat suppy	5	[kWth]

2. A 2 kWel fuel cell system

Data		
Power bought from the grid	513	[kWh/year]
Additional heat required	1066	[kWh/year]
Fuel cell size	2	[kWel]

General constants and figures

Economy parameters

Price of power	0.13	[$/kWh]
Goverment support for sold power	0.02	[$/kWh]
Total price for sold power	0.15	[$/kWh]
Power tax	0.015	[$/kWh]
Price for grid connection	0.02	[$/kWh]
Total cost of power for customer	0.165	$/kWh]
Hydrogen pipeline	680	[$/m]
District heat pipeline	425	[$/m]
Interest rate	8	[%]
System deprecation time	20	[Year]
Distribution system deprecation time	40	[Year]
Annuity factor for system	0.101852209	
Annuity factor for distribution components	0.083860162	
Annuity factor for fuel cell	0.250456455	
Exchange rate, 1US$ in AU$	1.4	
Price of fuel cell system	2,100	[$/kW]
Scale factor for fuel cell system	0.8	
Price of fuel cell system	1500	[US$/kW]
Annuity factor for burner	0.101852209	

Conditions

Average heat demand	5330	[kWh/building,year]
Average power demand	1900	[kWh/building,year]
Bought power from the grid	304	[kWh/year]
Total bought power from the grid	30400	[kWh/year]
Additional heat needed	0	[kWh/year]
Number of buildings	100	
Hours of a year	8760	[Hours]

Constants

LHV hydrogen	2.8	[kWh/Nm3]
Hydrogen density	0.084	[kg/Nm3]

Attention!

When the indata is altered in this sheet, the variation sheet should be reset.
If the reset button is not pushed the variation sheet will show old results.
Do not change the position of the parameters in this sheet. It will cause faults in the VBA-program where a specific parameter relates to a specific cell.

Reset variation sheet

Natural gas

System efficiencies

	Central	Split	Local
System power efficiency	0.35	0.35	0.35
Total system efficiency	0.85	0.75	1.00
Burner efficiency	0.94	0.94	0.94
Reformer efficiency		0.90	

Technical calculation

	Central	Split	Local	
Total loss of heat in pipes	65,700	-	-	[kWh/year]
Total produced heat by system	598,700	533,000	533,000	[kWh/year]
Total fuel flow into reformers	1,197,400	1,332,500	8,200	[kWh/year]
Produced power in each fuel cell	419,090	4,664	2,870	[kWh/year]
Total produced power	419,090	466,375	287,000	[kWh/year]
Total fuel need	1,197,400	1,332,500	820,000	[kWh/year]
Fuel cell size requirement	350.0	4.38	2.69	[kWel]
Number of 250 kW fuel cells	1	0	0	
Size of complementing fuel cell	100	4.4	2.7	[kWel]
Power sold to the grid	259,490	306,775	127,400	[kWh/year]

Economic calculations

Distribution components

	Central	Split	Local	
Fuel pipeline	105,000	105,000	157,500	[$]
Hydrogen pipeline	-	340,000	-	[$]
District heating pipeline	212,500	-	-	[$]
Total pipeline cost	317,500	445,000	157,500	[$]
Capital cost of pipelines	26,626	37,318	13,208	[$/year]

Total system cost

	Central	Split	Local	
Fuel cell system	257,611	545,982	463,788	[$]
Burner	-	-	-	[$]
System cost	257,611	545,982	463,788	[$]
Buildings and help equipment	25,761	54,598	23,189	[$]
Improvment of land	25,761	27,299	-	[$]
Total system cost	309,134	627,879	486,977	[$]
Capital cost of system	31,486	63951	49600	[$/year]

Variable costs

	Central	Split	Local	
Distribution system	26,626	37,318	13,208	[$/year]
O&M distribution	-	-	-	[$/year]
Power sold to the grid	- 38,924	- 46,016	- 19,110	[$/year]
Power bought from the grid	3,952	3,952	3,952	[$/year]
Fuel	32,330	35,978	22,140	[$/year]
O&M system	3,149	6,395	4,960	[$/year]
O&M fuel cell	16,100	34,123	28,986	[$/year]
Unforseen expenses	3,149	6,395	4,960	[$/year]
Tax deduction	13,052	13,858	9,553	[$/year]
Total variable cost	59,433	92,002	68,649	[$/year]

Constants

LHV fuel	11.2	[kWh/Nm3]
Fuel density	0.85	[kg/Nm3]

Economy parameters

Fuel	0.03	[$/kWhfuel]
Energy tax fuel	0.01	[$/kWhfuel]
Carbon dioxide tax	0.01	[$/kWhfuel]
Fuel pipeline	105	[$/m]
Transport by truck	-	[$/m]
Amount of fuel per truck	-	[kWh/truck]

Reference case

Technical calculation

Bought power from the grid	1,900	[kWh/building,year]
Total bought power from the grid	190,000	[kWh/year]
Produced heat by burner	5,330	[kWh/building,year]
Total produced heat by burners	533,000	[kWh/year]
Total amount of fuel used in burners	567,021	[kWh/year]

Economical calculation

Total burner price	32,500	[$]
Fuel pipeline	157,500	[$]
Capital cost pipeline	13,208	[$/year]
Capital cost burners	3,310.20	[$/year]
O&M cost burners	1,625	[$/year]
Price of total bought power	24,700	[$/year]
Price of fuel	17,011	[$/year]
Total cost	59,854	[$/year]
Total cost per building	599	[$/year]

Attention!

When the indata is altered in this sheet, the variation sheet should be reset.
If the reset button is not pushed the variation sheet will show old results.
Do not change the position of the parameters in this sheet. It will cause faults in the VBA-program where a specific parameter relates to a specific cell.

Reset variation sheet

Push the button and the cells returns to their standard values

Standard values

3] D. Partial heat supply strategy scaling factor approach

In and result data

In

Distance between the fuel source and a central system location	1000 [m]
Distance between a central system location and the building area	500 [m]
Type of demand supply, 1 = All heat, 2 = 2 kWel	2

Result

Total cost [$/year]	Central	Split	Local	Reference
Natural gas	73,960	120,897	110,635	59,854

Cost per building [$/year]	Central	Split	Local	Reference
Natural gas	740	1,209	1,106	599

About the program

The main objective with the program is to calculate the costs for three different configurations of fuel cell systems, see configuration sheet.
Chose the type of heat demand approach in this sheet.
Chose the distances in this sheet.
Parameters for the chosen fuel can be changed in the fuel sheet.
General parameters that apply for all fuels can be changed in the demand and standard values sheet.
The results for the chosen parameter values are given in the In and result data sheet.
The impact of different parameters can be studied in the variation sheet.
The variation of other parameters can be done with VBA in the variation sheet.

Attention!
When the indata is altered in this sheet, the variation sheet should be reset.
If the reset button is not pushed the variation sheet will show old results.

Reset variation sheet

Push the button and the cells returns to their standard values

Standard values

Demand of buildings

Standard values

Push the button and the cells returns to their standard values

Yearly heat demand	5,330	[kWh/year]
Yearly power demand	1,900	[kWh/year]

1. All heat supplied by fuel cell

Data		
Power bought from the grid	304	[kWh/year]
Additional heat required	0	[kWh/year]
Fuel cell size	2.69	[kWel]
Fuel cell maximum heat suppy	5	[kWth]

2. A 2 kWel fuel cell system

Data		
Power bought from the grid	513	[kWh/year]
Additional heat required	1066	[kWh/year]
Fuel cell size	2	[kWel]

General constants and figures

<u>Economy parameters</u>

Price of power	0.13	[$/kWh]
Goverment support for sold power	0.02	[$/kWh]
Total price for sold power	0.15	[$/kWh]
Power tax	0.015	[$/kWh]
Price for grid connection	0.02	[$/kWh]
Total cost of power for customer	0.165	$/kWh]
Hydrogen pipeline	680	[$/m]
District heat pipeline	425	[$/m]
Interest rate	8	[%]
System deprecation time	20	[Year]
Distribution system deprecation time	40	[Year]
Annuity factor for system	0.101852209	
Annuity factor for distribution components	0.083860162	
Annuity factor for fuel cell	0.250456455	
Exchange rate, 1US$ in AU$	1.4	
Price of fuel cell system	2,100	[$/kW]
Scale factor for fuel cell system	0.8	
Price of fuel cell system	1500	[US$/kW]
Annuity factor for burner	0.101852209	

<u>Conditions</u>

Average heat demand	5330	[kWh/building,year]
Average power demand	1900	[kWh/building,year]
Bought power from the grid	513	[kWh/year]
Total bought power from the grid	51300	[kWh/year]
Additional heat needed	1066	[kWh/year]
Number of buildings	100	
Hours of a year	8760	[Hours]

<u>Constants</u>

LHV hydrogen	2.8	[kWh/Nm3]
Hydrogen density	0.084	[kg/Nm3]

Attention!

When the indata is altered in this sheet, the variation sheet should be reset.
If the reset button is not pushed the variation sheet will show old results.
Do not change the position of the parameters in this sheet. It will cause faults in the VBA-program where a specific parameter relates to a specific cell.

Reset variation sheet

Natural gas

System efficiencies

	Central	Split	Local
System power efficiency	0.35	0.35	0.35
Total system efficiency	0.85	0.75	1.00
Burner efficiency	0.94	0.94	0.94
Reformer efficiency		0.90	

Technical calculation

	Central	Split	Local	
Total loss of heat in pipes	65,700	-	-	[kWh/year]
Total produced heat by system	492,100	426,400	426,400	[kWh/year]
Total fuel flow into reformers	984,200	1,192,005	6,560	[kWh/year]
Produced power in each fuel cell	344,470	3,731	2,296	[kWh/year]
Total produced power	344,470	373,100	229,600	[kWh/year]
Total fuel need	1,097,604	1,192,005	769,404	[kWh/year]
Fuel cell size requirement	200.0	2.00	2.00	[kWel]
Number of 250 kW fuel cells	0	0	0	
Size of complementing fuel cell	200	2.0	2.0	[kWel]
Power sold to the grid	205,770	234,400	90,900	[kWh/year]

Economic calculations

Distribution components	Central	Split	Local	
Fuel pipeline	105,000	105,000	157,500	[$]
Hydrogen pipeline	-	340,000	-	[$]
District heating pipeline	212,500	-	-	[$]
Total pipeline cost	317,500	445,000	157,500	[$]
Capital cost of pipelines	26,626	37,318	13,208	[$/year]

Total system cost	Central	Split	Local	
Fuel cell system	145,560	299,935	365,631	[$]
Burner	3,448	32,500	32,500	[$]
System cost	149,008	332,435	398,131	[$]
Buildings and help equipment	14,901	33,243	19,907	[$]
Improvment of land	14,901	16,622	-	[$]
Total system cost	178,810	382,300	418,038	[$]
Capital cost of system	18,212	38938	42578	[$/year]

Variable costs				
Distribution system	26,626	37,318	13,208	[$/year]
O&M distribution	-	-	-	[$/year]
Power sold to the grid	- 30,866	- 35,160	- 13,635	[$/year]
Power bought from the grid	6,669	6,669	6,669	[$/year]
Fuel	29,635	32,184	20,774	[$/year]
O&M system	1,821	3,894	4,258	[$/year]
O&M fuel cell	9,313	20,777	24,883	[$/year]
Unforseen expenses	1,821	3,894	4,258	[$/year]
Tax deduction	10,728	12,384	7,642	[$/year]
Total variable cost	55,748	81,959	68,057	[$/year]

	Central	Split	Local	
Total cost	73,960	120,897	110,635	[$/year]
Total cost per building	740	1,209	1,106	[$/year]

Constants

LHV fuel	11.2	[kWh/Nm3]
Fuel density	0.85	[kg/Nm3]

Economy parameters

Fuel	0.03	[$/kWhfuel]
Energy tax fuel	0.01	[$/kWhfuel]
Carbon dioxide tax	0.01	[$/kWhfuel]
Fuel pipeline	105	[$/m]
Transport by truck	-	[$/m]
Amount of fuel per truck	-	[kWh/truck]

Reference case

Technical calculation

Bought power from the grid	1,900	[kWh/building,year]
Total bought power from the grid	190,000	[kWh/year]
Produced heat by burner	5,330	[kWh/building,year]
Total produced heat by burners	533,000	[kWh/year]
Total amount of fuel used in burners	567,021	[kWh/year]

Economical calculation

Total burner price	32,500	[$]
Fuel pipeline	157,500	[$]
Capital cost pipeline	13,208	[$/year]
Capital cost burners	3,310.20	[$/year]
O&M cost burners	1,625	[$/year]
Price of total bought power	24,700	[$/year]
Price of fuel	17,011	[$/year]
Total cost	59,854	[$/year]
Total cost per building	599	[$/year]

Attention!

When the indata is altered in this sheet, the variation sheet should be reset. If the reset button is not pushed the variation sheet will show old results. Do not change the position of the parameters in this sheet. It will cause faults in the VBA-program where a specific parameter relates to a specific cell.

Reset variation sheet

Push the button and the cells returns to their standard values

Standard values