Integrated top-down and bottom-up approaches in power generation planning using life cycle based evaluation

Ramachandran Kannan

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**School of Mechanical and Aerospace Engineering
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Singapore
February 2005

Ramachandran Kannan

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Summary

Integrated top-down and bottom-up approaches in power generation planning using life cycle based evaluation

Electricity is a major secondary energy carrier and is predominantly produced from fossil fuels. Challenging concerns of the fossil fuel based power generation are depletion of fossil fuels and global warming caused by greenhouse gases (GHG) from the combustion of fossil fuels. To achieve the goal of environmental sustainability in the power sector, a major action would be to reduce the high reliance on fossil fuels by resorting to the use of clean/renewable sources and efficient generation/use of electricity. The former is referred to as supply based top-down approach while the latter is referred to as energy efficiency based bottom-up approach. Both these approaches have their own strengths and shortcomings. The top-down approach is seen as uneconomical but easy to execute whereas the bottom-up approach is cost-effective but faces great barriers in implementation. Thus, neither the top-down nor the bottom-up approach by itself can provide the ultimate solution in addressing the current energy-environmental issues. These two approaches need to be integrated for a sustainable power generation planning. In order to consider the long-term implications of power generation, a life cycle concept is adopted, which is a cradle-to-grave approach to analyse an energy system in its entire life cycle. Life cycle assessment (LCA) is an effective tool to pinpoint the environmental implications but it does not account for economic implications. Life cycle cost analysis (LCCA) provides effective evaluation to pinpoint cost effective alternatives but it does not account for any potential environmental impact of such alternatives. Thus, LCA and LCCA should be combined to identify cost effective power generation alternative with possible minimum global warming potential (GWP).

This research is aimed to develop a framework for power generation planning by incorporating the supply based top-down and energy efficiency based bottom-up approaches using LCA and LCCA as tools. Its scope is to develop power generation scenarios for Singapore to foresee the emission reduction opportunities in Singapore's power sector.

The LCA and LCCA models are developed and the life cycle energy, emissions and cost inventory are established for power generation and consumption technologies in Singapore. In selected cases, simple correlations are established. The LCA of fossil fuel based power generation technologies reveals that hidden upstream processes account for 10-18 % of the life cycle energy use and GWP.

A top-down model has been developed for scenario studies and applied to the Singapore power sector. The supply based top-down scenarios reveal that for a 4 % annual electricity growth rate during 2004-2013, it would not be possible to reduce the GHG emissions from today's level unless and until power generation switches over to 100 % natural gas. However, a 100 % gas based power generation may pose concerns on fuel security. It would also require additional sources for gas supply, as the current gas import would not be adequate to meet the power sector demand. If fuel oil or Orimulsion form a part of the power generation mix, it would not be possible to reduce GHG emissions from today's level. If solar PV based power generation were to supply 2-3 % of the total demand during the selected time horizon, which is considered the maximum it could provide, the resulting change in the GHG emission would be insignificant. Also, it would not be a cost effective option. Therefore, if Singapore were to limit the GHG emission from its power sector, there is no supply based top-down options available that will take into account the need for fuel security, cost effectiveness and limits on emission.

An integrated framework is developed by incorporating two bottom-up measures viz. district cooling service and cogeneration, in the top-down model. This framework is capable of considering the demand side measures (DSM) inclusive of any subsidy/administrative cost incurred in the DSM. Using this framework, integrated power generation scenarios are studied. With this approach, emission reduction would be possible even if fuel oil/Orimulsion is used in power generation. For instance, by using fuel oil/Orimulsion for a 10 % of the power generation mix, there would be an emission reduction of about 0.9 - 1.8 % from today's level if 10 - 15 % of the power is generated from cogeneration. However, in absence of the cogeneration, the emission would increase at a rate of 0.1 - 0.95 %. Therefore, energy efficiency would be the only option for Singapore to limit its emissions.

The models developed in this research can be used to perform scenario studies at the power generation planning level to foresee fuel demand, CO₂ and GHG emissions, and cost of power supply under various power generations mix. The same methodology would be replicable in other energy sectors.

Publications arising from this thesis

Journal articles

- [1]. R. Kannan, C.P. Tso, Ramli Osman and H.K. Ho (2004), LCA-LCCA of oil-fired steam turbine power plant in Singapore, *Energy Conversion and Management* **45** (18-19) 3093-3107.
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- [3]. R. Kannan, K.C. Leong, R. Osman, H.K. Ho and C.P. Tso (2005), Life cycle assessment study of solar PV systems: An example of a 2.7 kW_p distributed solar PV system in Singapore, *Solar Energy* (in press)
- [4]. R. Kannan, K.C. Leong, Ramli Osman and H.K. Ho (2005), Life cycle energy, emissions and cost inventory of power generation technologies in Singapore, *Renewable and Sustainable Energy Reviews* (in press).

Conference presentations

- [5]. R. Kannan, C.P. Tso, Ramli Osman and H.K. Ho (2003), Life cycle energy use and GHG emission analysis in electricity generation from a oil-fired power plant in Singapore, *Solutions to Pollution*, 28 September - 1 October 2003, Christchurch, New Zealand, p. 93.
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Nomenclature

Abbreviations

AC	- Alternate current
ADB	- Asian Development Bank
AHP	- Analytical Hierarchy Process
APEC	- Asia Pacific Economic Cooperation
APEREC	- Asia Pacific Energy Research Center, Japan
ASHRAE	- American Society of Heating, Refrigerating and Air-Conditioning Engineers
BCA	- Building Construction Authority, Singapore
BP	- British Petroleum
BSCS	- Building Specific Cooling System
CExC	- Cumulative exergy consumption
CH ₄	- Methane gas
CIS	- Copper indium diselenide based solar cells
CO ₂	- Carbon dioxide gas
Cogen	- Cogeneration
COP	- Conference of the Parties, UNFCCC
DC	- Direct current
DCS	- District Cooling Service
DG	- Distributed generation
DoD	- US Department of Defence
DoE	- US Department of Energy
DRPL	- Development Resources Pte Ltd., Singapore
DSM	- Demand side management / measures
EIA	- Energy Information Administration
ELCA	- Exergetic life cycle analysis
EMA	- Energy Market Authority, Singapore
EMC	- Energy Market Company, Singapore
EPA	- Environmental Protection Agency, USA

EPBT	- Energy pay back time
EPRI	- Electric Power Research Institute, California
GDP	- Gross Domestic Product
GEMIS	- Global Emission Model for Integrated Systems
GHG	- Greenhouse gases
GS	- Global GHG emission scenario
GWP	- Global warming potential
HP	- High pressure
HRSG	- Heat recovery steam generator
HSFO	- High sulphur fuel oil
HT	- High tension
IA	- Integrated scenarios/approach
IACEE	- Inter-Agency Committee on Energy Efficiency, Singapore
IP	- Intermediate pressure
IPCC	- Intergovernmental Panel on Climate Change
ISO	- International Organisation for Standardisation
LCA	- Life cycle assessment/ Life cycle analysis
LCA-LCCA	- Life cycle assessment and life cycle cost analysis
LCC	- Life cycle cost
LCCA	- Life cycle cost analysis
LCEA	- Life cycle exergy analysis
LCI	- Life cycle inventory
LNG	- Liquefied natural gas
LP	- Low pressure
LS	- Local CO ₂ emission scenario
LT	- Low tension
MECO	- Material, energy, chemical others (LCA methodology)
MG	- Metallurgical grade (silicon)
N ₂ O	- Nitrous oxide gas
NEA	- National Environment Agency
NEMS	- National Electricity Market of Singapore
NREL	- National Renewable Energy Laboratory, USA

O & M	- Operation and maintenance
OPEC	- Organisation of the Petroleum Exporting Countries
PEMFC	- Proton exchange membrane fuel cell
PUB	- Public Utilities Board, Singapore
PV	- Photovoltaic (solar)
PVC	- Poly vinyl chloride
R&D	- Research and development
S\$	- Singapore dollars
SEP	- Singapore Electricity Pool
SETAC	- Society of Environmental Toxicology and Chemistry, Pensacola
SOFC	- Solid oxide fuel cell
SOFC-GT	- SOFC-gas turbine hybrid system
T&D	- Transmission and distribution
UN	- United Nations
UNEP	- United Nations Environment Programme
UNFCCC	- United Nations Framework Convention on Climate Change
US\$	- American dollars

Units and measurements

BTU	- British thermal units
EJ	- Exa Joule (10^{18} J)
g	- Gram
GJ	- Giga Joule (10^9 J)
GWh	- Giga Watt-hour (10^6 kWh)
h	- Hour
J	- Joule
kg	- Kilogram
kJ	- Kilo Joule (10^3 J)
km	- Kilometre
kVA	- Kilovolt Ampere
kW	- Kilowatt (10^3 W)

kWh	- Kilowatt-hour
m	- Meter
MJ	- Mega Joule (10^6 J)
mm	- Millimetre
MMBTU	- Million BTU
MW	- Mega Watt (10^6 W)
MWh	- Mega Watt-hour (10^3 kWh)
PJ	- Peta Joule (10^{15} J)
SCF	- Standard cubic feet
t	- Metric ton (tonne)
TJ	- Tera Joule (10^{12} J)
toe	- Tonne of oil equivalent
TWh	- Tera Watt-hour (10^9 kWh)
W	- Watt
y	- Year

Symbols

¢	- Cent
<i>B</i>	- Exergy
<i>CoP</i>	- Coefficient of performance
<i>C_p</i>	- Specific heat at constant pressure
<i>E</i>	- Energy
<i>P</i>	- Pressures
β	- Ratio of chemical exergy to heating value
<i>T</i>	- Temperature
η	- Efficiency

Subscripts

AC	- Heat driven absorption/absorption chiller
B	- Boiler
c	- Cooling energy

cc	- Combined cycle plant
Cogen	- Cogeneration
e	- Electrical energy
EC	- Electric chiller
ex	- Exergy
GT	- Gas turbine
HRSG	- Heat recovery steam generator
k	- Kinetic exergy
o	- Chemical exergy
p	- Potential exergy
p	- Peak power in solar PV modules
ph	- Physical exergy
s	- Steam
ST	- Steam turbine
t	- Thermal energy

Superscripts

cc	- Combined cycle plant
Cogen	- Cogeneration
GT	- Gas turbine

Nomenclature used in life cycle assessment model

Energy (C)	- Direct energy use in construction phase
Energy (D-D)	- Direct energy use in decommissioning-disposal phase
Energy (E-E) _i	- Energy use for exploration and extraction of i^{th} material
Energy (F) _i	- Embedded energy in i^{th} material (or Fuel energy)
Energy (j) _i	- Energy consumed for i^{th} material in j^{th} process
Emission (k)	- Emission of k^{th} pollutant
Energy (O)	- Direct energy used in the operational phase
Energy (P-M) _i	- Energy use for processing and manufacturing of i^{th} material
Energy(R _{cycle}) _i	- Energy use in recycling of i^{th} materials

Energy(R_{use}) _{<i>i</i>}	- Energy to be saved from the reuse of i^{th} material
Energy(T) _{<i>i</i>}	- Energy consumption in transportation of i^{th} material
$i = 1$ to n	- Number of materials involved in the energy system
m_i	- Mass of i^{th} material
Sp. Energy (j) _{<i>i</i>}	- Specific energy consumption to produce or process i^{th} material in j^{th} process

Nomenclature used in life cycle cost analysis model

$C_{D\&D}$	- Decommissioning and disposal cost
C_E	- Annual energy (fuel) cost
$C_{O\&M}$	- Annual O & M cost
C_{R_r}	- Replacement cost occur in r^{th} year
d	- Discount rate
e	- Escalation rate
i	- Interest rate
L	- Salvage value
n	- Life time of energy system
n_r	- Life time of repeated capital cost's equipment occurring every r^{th} year
P	- Capital cost
P_{r_r}	- Repeated capital costs occurring every r^{th} year

Nomenclature used in bottom-up model

A	- Total national life cycle primary energy use
a	- National average specific life cycle energy use
a_i	- Specific life cycle energy use from i^{th} energy sources/technologies
B	- Total national life cycle GWP
b	- National average specific life cycle GWP
b_i	- Specific life cycle GWP from i^{th} energy source
C	- Total national life cycle cost

c	- National average specific life cycle cost of electricity generation
c_i	- Specific life cycle cost of electricity generation from i^{th} energy source/technology
p_{x_u}	- Percentage of electricity consumed in u^{th} sector
$p_{x_u y_v}$	- Percentage of electricity consumed for v^{th} service in u^{th} sector
$p_{y_v z_w}$	- Percentage of electricity consumed by w^{th} technology in v^{th} services
Q_d	- National electricity demand
q_i	- Quantity of electricity generated from i^{th} energy sources/technologies
Q_s	- National electricity supply
$Q_{T\&D}$	- T&D losses
q_{x_u}	- Electricity demand in u^{th} sector
$q_{x_u y_v}$	- Quantity of electricity consumed for v^{th} service in u^{th} sector
$q_{x_u y_v z_w}$	- Quantity of electricity consumed in w^{th} technology for v^{th} energy services in u^{th} sector.

1. Introduction

1.1. Background

Energy is the key element in economic and social development. The United Nations Commission on Sustainable Development emphasised that 'energy is central to achieve the goals of sustainable development' (UN, 2001). The world's total primary energy consumption has been increasing due to increasing economic activities and spiralling population growth. Our primary sources of energy supply are fossil fuels (crude oil, coal and natural gas), nuclear fuel and renewable energy sources (hydro, geothermal, solar, wind, biomass, etc). Over 85 % of the primary energy supply has been met from fossil fuels. In 2002, the world's total primary energy consumption was about 427 EJ and it grew at an average annual rate of 1.5 % during 1992 to 2002 (EIA, 2004a). The world's population is projected to be 8-11 billion by 2050 (IPCC, 2001a) and the primary energy demand is projected to increase by 54 % during 2001-2025 (EIA, 2004).

Due to greater exploitation and consumption of fossil fuels, depleting¹ fossil reserve is a major concern on the future energy supply. On the other hand, global warming caused by continued buildup of greenhouse gas (GHG) from combustion of fossil fuels is one of the most challenging environmental concerns facing the world population. During the past 20 years, about three-quarters of the anthropogenic emission of CO₂ was due to fossil fuel burning (IPCC, 2001a). There is a discernible human influence on global climate (IPCC, 1995) and the consequences of global warming are very serious, as discussed extensively in IPCC (2001a; 2001b). Nowadays, in a typical year, occurrence of natural catastrophes, such as major

¹ The debate over depleting oil/natural gas reserves generated controversy and was discussed in the survey of World Energy Council (2001).

hurricanes and tornadoes, is five times more than in the 1960s (Mills, 1998). A clear trend in increasing weather related natural catastrophe and damages² is observed in the recent past (Munich Re, 2004). The world's CO₂ emission is projected to grow by 1.9 % per year if the world's energy consumption reaches the projected level of EIA (2004). The resulting climatic effects will cause considerable losses to all regions of the world and will intensify if the nations that are highly responsible for emission do not reduce their emissions (Kemfert, 2002).

Global warming is a long-term problem and will require strategic thinking for its solution. Therefore we should think not only about mitigation, but also about adaptation as well. The journey towards the goal of environmental sustainability is incredibly complex, and will have an impact on all aspects of human life. Success will not be achieved overnight but may take generations to materialise. However, without remedial actions, the problem will aggravate as the overall energy use continues to rise. Global communities are working together to reduce GHG emission. Ever since the awareness of global warming came to prominence at the Earth Summit in Rio de Janeiro in 1992, government policy makers, private industries, international aid agencies and non-governmental organisations have been in a rhetorical tug-of-war over its implications. The Kyoto Protocol in 1997 sowed the fertile seeds to solve the climate change problems (UNFCCC, 1997). Negotiations between concerned parties have attempted to define the basic elements of emission mitigation mechanisms, like, clean development mechanism (CDM), emissions trading and joint implementation (JI).

² In 1996, 600 catastrophes occurred, causing 12,000 deaths and \$9 billion losses (Mills, 1998). In 1998, 56 countries affected by severe floods and at least 45 droughts due to the climate change (The Independent, 1999). The estimated losses in 1998 was US\$ 89 billion and 32,000 people died, which was more than the total loss experienced throughout the 1980s (Meyer, 2000). Since 1996, 20,045 people killed and 256 million people affected by hero-meteorological disasters, and the damage during 1990-99 was US\$ 629 billion (Helmer, 2002). Damage due to natural catastrophes during January to September 2002 alone was US \$56.4 billion and over 9,400 people killed (UNEP, 2002).

1.2. Power sector

The world's electricity consumption is ever increasing and is expected to double over the next two decades. Global power demand is projected to increase by 2.3 % per year during 2001-2025 while it would be 3.7 % in Asia (EIA, 2004). In 2001, about 64 % of the world's electricity was generated from fossil fuels while it was 73.5 % in Asia and Oceania (EIA, 2004a). Much of the forecasted power demand will be generated with fossil fuels (Barker and Srivastava, 2001). This is because fossil fuel prices for electricity production are projected to remain low relative to the costs of nuclear power and renewable energy sources. As a result, non-fossil fuels are not expected to be economically competitive with fossil fuels over a forecast period of 2001-2025 (EIA, 2004). Hence, power generation and their interaction with the economy plays a key role in the elaboration of national and international strategies to combat the threat of climate change.

In many nations, especially in the developed countries, the electricity market is experiencing significant changes towards deregulation, which aimed to provide electricity at a competitive (minimum) price.³ These changes caused the decisions on power generation to be no longer dependent on the state- or utility owned monopoly but rather on decentralised decisions of generation companies, whose goal is to improve economic efficiency to maximise their profits. As a result, environmental concerns and long-term availability of fuels are inadequately addressed. To achieve the goal of environmental sustainability in power sector, a major action would be to reduce the high reliance on fossil energy by resorting to the use of more clean and renewable

³ The review by Blauvelt (2004) shows that there is no substantial evidence to prove that deregulation has brought down the price in the European Union countries as other factors could have contributed to price reduction. However, it does not prove that market opening has been successful or unsuccessful in reducing the prices.

sources and smarter use of electricity without compromising economic growth⁴. These must be practised before fossil fuels are completely depleted or become prohibitively expensive.

1.3. Power generation planning

Power generation expansion planning is the planning of electricity generation to meet the forecasted demand. In energy planning, two approaches, viz. top-down and bottom-up, are broadly discussed and they are generally referred to as economic and engineering models, respectively (see Chapter 2). However, clear-cut definitions for the top-down and bottom-up approaches are still lacking. Hence, it is sometimes difficult to decide whether a particular action or measure belongs to one or the other category. This simple characterisation of top-down and bottom-up models is increasingly misleading as more recent versions of each approach have tended to provide greater detail in the aspects that were less developed in the past (IPCC, 1996). Considering this limitation and to demonstrate these two approaches specific to the power generation sector, the top-down and bottom-up approaches are defined as follows (see Figures 2.1 and 2.2 for descriptions):

The top-down approach is defined as any action or measure that leads to *new capacity addition to the prevailing power supply to cope with the forecasted power demand or GHG emission reduction targets*.

The bottom-up approach is defined as any action or measure that leads to

(i) improving the electricity utilisation at the demand side,

⁴ An alternative way to mitigate GHG impact is carbon sequestration. CO₂ capture and storage have demonstrated the potential for reductions in emissions (Lombardi, 2001; Freund, 2003; Røren, 2001). However, based on a study by Gagnon et. al (2002), CO₂ storage involves huge amounts of energy and pollution, and therefore its relative benefits should be much less.

(ii) *improving the power generation efficiency and*

(iii) *developing synergy between (i) and (ii).*

Both these approaches have their own strengths and shortcomings (see Sections 2.3 and 2.4). Unfortunately, neither the supply-based top-down approach nor the energy efficiency-based bottom-up approach by itself can be the *ultimate* solution in addressing the current energy-environmental issues. Therefore, integrating both approaches in power generation planning could provide better long-term results. Deployment of new energy systems (a top-down approach) and the execution of energy efficiency measures (a bottom-up approach) can result in a sustainable power supply system to meet the future demands.

Modern power generation technologies exhibit good environmental performance in the user phase but can lead to higher absolute environmental impacts in the production and/or disposal phases. A similar characteristic is replicated on the economic side with low O & M costs but huge capital costs.

The current appraisal techniques often ignore the long-term impacts. For sustainable power supply availability, long-term environmental implications and cost effectiveness of power generation technologies must be taken into account. Only a life cycle based evaluation tool can bring insights on their sustainability. Life cycle assessment (LCA) and life cycle cost analysis (LCCA) are effective tools that can be used for the appraisal of various options in the top-down and bottom-up approaches. Hence, integrating the top-down and bottom-up approaches in power generation planning using LCA-LCCA tools could be adopted as a methodology to address the concerns on security of power supply and the threat of global warming. With this

background, this research aims to explore the effectiveness of this integrated approach by applying it to Singapore power sector.

1.4. Research objectives

The objective of this research is to develop a framework for sustainable power generation planning based on the principle of integrating the top-down and bottom-up approaches described in the previous sections (also see Section 2.5). In this research, the term "power generation planning" refers to a set of illustrative power generation mix scenarios based on the top-down and bottom-up approaches to show their emission and cost effectiveness. It is not aimed to forecast the power demand but rather to use the forecasted power demands for power generation planning. The sustainability is characterised by cost effective power supply with possible minimum Global Warming Potential (GWP) and smart use of fossil fuels. Hence, GWP, primary (fossil) energy consumption and cost are considered as the prime indicators and estimated using the LCA and LCCA models.

1.5. Scope of the research

The scope of this research is to study power generation mix scenarios for Singapore in order to meet the forecasted power demand and any GHG emission reduction target. Singapore's per capita energy consumption and CO₂ emissions are on par with those of the Annex-I countries of the Kyoto Protocol (see Table 7.1). Although Singapore is not yet a signatory to the Protocol, sooner or later, Singapore, with or without international pressures, will have to face up to the challenge of limiting or reducing its GHG emission (also see the explanations in Section 7.1). Bearing this in mind, this research is set to study power generation scenarios for Singapore using the integrated framework developed in this research. The scenarios presented do not

predict what the future will be or even what it should be like. Their primary use is to explore the possibilities.

For power generation scenarios study, a top-down model and integrated framework are developed. They are aimed to estimate the national total life cycle primary energy use, emissions and the cost of the power supply under the various power generation mix scenarios. LCA and LCCA models are developed to establish the life cycle energy use, emissions and cost inventories, which are the key inputs to the top-down model and integrated framework. The scenarios of both the top-down and integrated approaches are compared in order to differentiate the significance of the integrated framework. The national total life cycle inventories (energy use, emission and cost) are used as criteria for such a comparison.

Usually, the national GHG emission inventories are established based on the fuels consumed within the national territory, i.e. the emissions outside the national territory are not included in the GHG emission inventory, even though those emissions are the result of economic activities within the nation. For this research, the GHG emission inventory for Singapore's power sector is estimated based on their life cycle emissions (see Section 7.3).

1.6. Outline of thesis

This thesis is divided into eight chapters including this introductory chapter. References are provided in alphabetical order at the end. Secondary facts and information are given as footnotes.

Chapter 2 provides a critical review of the literature and the rationale for the proposed research. The definitions of the top-down and bottom-up approaches from published work are compiled under Section 2.2. The conventional framework on the

top-down approach of power generation planning and its uncertainties are presented in Section 2.3. In Section 2.4, the application of the bottom-up approach to power generation and its advantages and disadvantages are presented. The strengths and shortcomings of the both approaches are summarised and the rationale behind the integrated approach are given in Section 2.5. In Sections 2.6 - 2.8, LCA, LCCA and Exergetic life cycle analysis (ELCA) works are compiled and their importance and limitations are highlighted. At the end of this chapter, an overall summary is given.

In Chapter 3, the methodology and procedures used for this research are described. Sections 3.2 and 3.3 illustrate the equation and formulae used in LCA-LCCA models. Section 3.4 describes the LCA-LCCA methodology of the bottom-up model with the decomposition analysis of power demand. The methodology of integrated framework is given in Section 3.5.

Chapter 4 presents five case studies on potential electricity generation technologies in Singapore for which LCA and LCCA were carried out. There are three centralised power generation technologies viz. a 250 MW oil-fired steam turbine, a 365.7 MW gas-fired combined cycle plant and a 250 MW Orimulsion-fired steam turbine, and two distributed power generation technologies viz. a 2.7 kW_p solar PV system and a 5 kW proton exchange membrane fuel cell (PEMFC). The LCA and LCCA of the five power generation technologies are presented in Sections 4.2 to 4.6.

Chapter 5 presents the case studies used in the bottom-up approach. Sections 5.2 and 5.3 describe the district cooling service (DCS) and the building specific cooling systems (BSCS). LCA and LCCA of the DCS and BSCS are presented in Sections 5.4 and 5.5. Section 5.6 compares the energy use, GWP and the costs of DCS and BSCS.

As another bottom-up measure, cogeneration is described in Section 5.7, including its energy saving estimation methodologies.

Chapter 6 analyses the relevance of exergy in the integrated approach. In Section 6.2, ELCA of the oil-fired steam turbine and gas-fired combined cycle plants are shown. In Sections 6.3 and 6.4, streamlined LCA and ELCA of hypothetical energy demands are compared to highlight their relevance in the bottom-up and integrated approaches. The uncertainties in the exergy calculations are highlighted in Section 6.5.

Chapter 7 presents the power generation scenarios developed using the top-down model and the integrated framework. In Section 7.2, an overview of the Singapore's power sector is presented. Section 7.3 explains the difference between conventional emission inventories and life cycle-based emission inventories. In Section 7.4, power generation mix scenarios are developed for the period of 2004-2013 using the top-down model. Their fuel demand, primary energy use, CO₂ and GHG emissions and costs are estimated. Section 7.5 describes two bottom-up measures using the district cooling service and cogeneration. The integrated power generation scenarios and their primary energy use, GHG emissions and cost are also presented in the Section 7.5. In Section 7.6, results of both approaches are discussed and the effectiveness of the integrated framework is illustrated.

Chapter 8 summarises the overall outcome of this research and the significances of models developed in this study are highlighted. Recommendations for emission reduction in Singapore's power sector are presented in Section 8.3. Some suggestions are also made to extend this research.

2. Literature Review

2.1. Introduction

The first ever energy model appears to be developed in 1968 when a steep growth in energy consumption was noticed in the 1960s (McVeigh, 1984). In the 1970s and 1980s, more energy system models were developed as the result of increased public interest in energy policy issues (Bergman, 1988). A summary on the general purposes of energy models is given by Knight (1989). From the late 1990s to the present, more energy and environmental models are being developed for energy planning by incorporating energy, economy and environmental interrelations, which are described in this chapter.

In energy planning, the top-down and bottom-up approaches are generally referred to as economic and engineering models, respectively. This can be attributed to the fact that earlier energy planning was done mainly by economists as part of the overall economy planning to ensure fuel supply and maintain power sector infrastructures. At later stages, detailed engineering and technological information are incorporated into energy planning by the involvement of engineers. Hence, it is presumed that the top-down models do not consider engineering and technological details and only the bottom-up models consider such details. However, both approaches incorporate engineering and technological information in different ways.

2.2. Definitions

This section compiles the definitions and/or explanations available for the top down and bottom-up approaches in the literature.

2.2.1. Top-down approach

The top-down approach is an aggregated macro-economic model that draws on an analysis of historical trends and relationships to predict the interactions between the energy sector and the rest of the economy. Top-down models typically incorporate relatively little detail on energy consumption and technological change compared with bottom-up models (IPCC, 1996).

It is an economic model that relies on the assumption that economic agents are rational. In contrast to the detailed technological information used in bottom-up models, the behaviour of energy demand in top-down models relies on few parameters (Müller, 2000).

The top-down models give more consideration to linkages between a given sector and a set of measures and macroeconomic parameters like gross domestic product (GDP) and final household consumption (Hourcade and Shukla, 2001).

It is a macro-economic model, in which the economy and energy systems are analysed based on aggregated data and they are weak in their representation of technology and fuel detail (Pandey, 2002).

It is an integrated approach to evaluate the various abatement technologies or instruments commonly applied by economists. The models are usually econometrically driven, have a predictive orientation, are based on historically derived parameter values, and consider the energy sector as part of the overall economic system (Jansen, 2002),

The top-down approach is often criticised by energy system analysts for its lack of detailed technological information on the energy system (Böhringer, 1998; Jaccard and Bataille, 2000).

Many energy models pertaining to the top-down approach are described in the literature (Nakicenovic et al., 1998; Leng, 2000; Monarque et al., 2002; Born, 2001; Capros et al., 1995; Capros, 1997; Stockholm Environment Institute, 1995; 2001). However, these models did not consider all aspects of the current energy-environment and its economic issues though they have their unique objectives.

2.2.2. Bottom-up approach

The bottom-up approach is defined as follows:

It incorporates detailed engineering of a wide range of technologies, and describes energy consumption in great detail (IPCC, 1996).

It is an engineering model that identifies profitable investments that would enhance energy efficiency at negative cost (no-regret potentials) (Müller, 2000).

It considers physical flows of energy and incorporate more technological details (Hourcade and Shukla, 2001).

It is an integrated approach to assess the impact and scope of the various technologies or options commonly applied by researchers in the tradition of technology and engineering. These models tend to explicitly focus on the technology factor in particular sectors, and are generally more detailed than the so-called top-down models (Jansen, 2002).

A wide range of studies and models are developed for energy efficiency options, which are for specific sectors or applications (Gielen and Yagita, 2002; Gielen and Moriguchi, 2002; Gielen and Chen, 2001; Chantanakome, 1996; Shahana, 1998; Lawrence Berkeley National Laboratory, 2001).

For this research, the top-down and bottom-up approaches are defined specific to the power sector (see Section 1.3).

2.3. Top-down approach in power generation planning

As a response to the need for a less carbon-intensive energy source, renewable energy is considered as the best solution to ameliorate the negative effects of fossil fuel consumption. Power generation policies are often inclined to meet the forecasted power demand and emission reduction targets through a supply-based top-down approach. Clean and renewable energy sources are considered as the primary solution in addressing current energy-environmental issues. The top-down approach leads easily to the consideration of the effects of mitigation on different broad sectors of the economy (not just the energy and capital goods sectors), so that the literature on these effects tends to be dominated by this approach (Barker and Srivastava, 2001).

Figure 2.1 illustrates a conventional top-down approach, in which the forecasted power demand is supplied by new capacity additions, with few details incorporated on demand level energy efficiency and technology change. Based on the capital cost of the newly added capacity, the cost of power generation is estimated and compared with cost of the prevailing power generation for decision-making. If the cost of power generation from the newly added clean and renewable energy sources is not competitive with prevailing fossil fuel based power generation, those sources may be promoted through financial and fiscal incentives (Fells, 2002; Michaelowa, 2003).

In the case of GHG mitigation targets, clean and renewable based power system, e.g. solar photovoltaic (PV), wind, biomass or low carbon emitting fuel (natural gas), are added to the existing pool of power supply. Their emissions mitigation potentials are estimated with respect to the emissions from the prevailing power generation, and mitigation cost are estimated, as illustrated in Figure 2.1.

Fig. 2.1. Supply based top-down approach in power generation planning

Clean and renewable energy based power generation is widely explored in recent years. Throughout the world, a wide range of policy instruments has been developed in the last decade in an attempt to bring new forms of clean and renewable energy into the market place at low cost and in ways which provide incentives for reduced costs. Some technological advances in wind turbine and solar PV technology have led to their prominent role in renewable energy technologies, with wind energy being the fastest-growing source of renewable energy in the industrialised countries (EIA, 2004). By 2050, 50 percent of the world's energy use is expected to be from renewable energy sources (World Energy Council, 2001) such as hydro, solar PV and wind energy.

2.3.1. Bottlenecks of top-down approach

Often current policies are motivating the use of less carbon intensive fossil fuels. As a result, the power sector is shifting from coal to oil or natural gas.

Eventually, the gas and oil reserves will be exhausted much earlier than coal. Then the energy supply will have to revert to coal. Under this circumstance, current transition or actions would be effective in the short-term but are unsustainable in the long run.

Clean and renewable energy based power generation technologies have advantages over fossil fuel based power generation from the perspective of their resource availability and low GHG emissions (Dincer, 2002; Tsoutsos et al., 2005). Studies have shown that large-scale deployment of renewable energy has potential negative environmental implications in terms of material availability and waste disposal (Phylipsen and Alsema, 1995; Wind Power Monthly, 1999; Bjerregaard and Thor, 2002).

The requirement of silver for manufacturing solar PV modules could contribute to the depletion of silver resources. To meet five⁵ percent of the world's electricity production from solar PV modules, their production would require about 30 % of the current silver production (Phylipsen and Alsema, 1995). Large-scale installations of solar PV system generate a substantial amount of waste. A 1 MW solar PV system could generate as much as 100 tonnes of (used module) waste. Recycling of these materials would be difficult. For example, the glass waste from the modules may contain too much plastics (EVA foil) to be accepted by glass recyclers (Phylipsen and Alsema, 1995). Thus, used PV modules may have to be land filled, which may further lead to undesirable environmental impacts due to presence of trace of silver, a heavy metal, in solar PV cells.

⁵ In 2002, world electricity generation from geothermal, solar, wind, and wood and waste altogether accounted for 1.65 % of the total electricity generation (EIA, 2004a).

Wind Power Monthly (1999) reported that before 2005, 500-2000 tonnes of used wind turbine blade material would have to be disposed off annually in Europe. After 2005, it will increase to 7000 tonnes annually. Large composite blades constitute a big problem as only 20 % of recycled materials can be used successfully in other products (Bjerregaard and Thor, 2002). In recent years, more wind turbines have been installed and the amount of waste would be much higher than what had been predicted. At present, the annual production of glass fibre reinforced plastics for wind turbine blades is 50,000 tonnes (Bjerregaard and Thor, 2002).

Since the anticipated lifetime of the solar PV modules or wind turbine is more than 20 years, waste generation will lag behind the installations of renewable energy technologies by that period. As we increase the rate of use of renewable energy technology, the problem of a large-scale disposal of solar PV modules and/or wind turbines may arise in the future. So far, hardly any technology has been developed for disposal of solar PV modules or wind turbine blades. Solar industries are claiming that there should not be any environmental problem in disposing the PV modules because there is no hazardous material expected to be released by the modules (Inglin, 2002). However, we have seen that environmental problems could come in any form, like global warming from CO₂, a non-hazardous gas. In the past, environmental impact from energy sector was not assessed on a long-term basis. After the invention of the steam engine, fossil fuel was found to be the best source of energy supply. However, the environmental impacts of fossil fuel combustion and unlimited resource exploitation are known only in the last few decades, and currently GHG emission from fossil fuel combustion is the centrepiece of the world's environmental agenda. Therefore, we should be cautious about sustainability in the large-scale deployment of renewable energy technologies.

Though CO₂ emission targets could be achieved through renewable energy technologies, high capital requirement would hamper the wide-scale adoption of renewable energy (Takeshita et al., 1998; Barker and Srivastava, 2001). Fossil fuel prices for electricity production are projected to remain low relative to the costs of nuclear power and renewable energy sources; as a result, non-fossil fuels are not expected to be economically competitive with fossil fuels over a forecast period of 2001-2025 (EIA, 2004). Although renewable energy policies played a key role in GHG mitigation targets, they suffer from cost inefficiencies (Michaelowa, 2003). Considering uncertainties in long-term environmental sustainability and its capital-intensive nature, renewable energy alone cannot be the *ultimate* solution in addressing the current global warming concerns.

2.4. Bottom-up approach in power generation planning

Instead of catering to increasing power demand to achieve economic growth, demand can be stabilised and/or decreased through energy efficiency measures. Lovins et al. (1998) elucidated that natural resources can be used more efficiently in all domains of daily life, either by generating more products and services from the available resources or by using less resources to maintain the same standard. End-use technologies hold the largest potential for efficiency improvement in energy sector (Nørgård, 2002). The bottom-up approach offers the possibility of structural change, i.e. the emerging and phasing out of technologies (Frei et al., 2003). It has been estimated that energy efficiency measures have the potential to save 40 percent of energy used worldwide (Earth Summit, 2002) that could offset the projected primary energy demand of 60 percent, to an extent. Lovins et al. (1998) described that in industrialised countries energy efficiency opportunities can help prevent adverse effects on nature by reducing resource use without impairing the standard of living. In so-

called developing countries, they can help to improve the standard of living without over-exploiting nature.

2.4.1. Framework on bottom-up approach in power generation planning

The energy efficiency based bottom-up approach should, wherever feasible, be the preferred way to address current energy related environmental concerns. Figure 2.2 illustrates a bottom-up approach of power generation, wherein energy efficiency measures are employed to meet a part of the forecasted new power demand.

Fig. 2.2. Energy efficiency based bottom-up approach in power generation

The measures at the end use can reduce the overall power demand, thereby reducing demand on the existing power supply, as shown by the shaded block in the

Figure 2.2. Such measures could reduce future demand as well. The reductions achieved in the existing demand can be used to offset a part of the forecasted new power demand. A typical example under this category is introduction of cross-cutting technologies such as energy efficient motors, low energy consuming chillers, refrigerators and appliances at the demand side.

Measures in improving power generation efficiency are intended to utilise *existing* power sector infrastructures more effectively so that additional power generation could be made available for the same quantity of fuel consumption. For example, by introducing technological changes (e.g. boiler improvements, auxiliary power reductions, control system upgrades, etc.), and operational changes to achieve plant load optimisation wherever feasible, combined cycle plants can be used to augment or replace existing steam turbine plants. The additional power generated through these measures can be used to meet part of the forecasted new power demand as illustrated in Figure 2.2.

The measures under the above two categories can be implemented independently. The third category requires synergy between supply and demand. Such measures are intended to recover more heat from the power plant that could be used to replace electricity or other fuels at the demand side, for example, combined heat and power or heat driven district cooling. In the case of district cooling, an absorption chiller can recover heat from power plant and provide cooling services thereby reducing the electricity demand. Impacts from the measures under this category would be a combination of the above two categories.

Therefore, the bottom-up approach should be considered as a part of power generation planning as it can reduce the overall power demand. A great advantage of energy efficiency is its long-term benefits, which can be effective regardless of the

power supply scenario. This bottom-up approach frequently suggests emission savings, as against the mitigation efforts in the top-down approach. Thus, the bottom-up approach can be considered as a preventive strategy instead of a cure. Despite its many advantages, many barriers (see Section 2.4.2) may cause it to be excluded from consideration at the power generation planning level.

2.4.2. Bottlenecks of bottom up approaches

Despite many advantages of the energy efficiency based bottom-up approach, and a wide variety of sector-specific and cross-cutting energy efficiency improvement opportunities identified (Worrel et al., 2001), adoption of energy efficient technologies is still lacking. There is a gap between the opportunities for cost-effective energy efficiency investment identified in energy models and what is adopted in practice. The origins of the gap are believed to be series of barriers, such as lack of capital, dearth of information, hidden costs, etc. (Sorrell et al., 2000). Evidence illustrates that many transaction barriers severely limit the adoption of energy efficiency measures (Martinot, 1995; Koopmans and te Velde 2001; Worrel et al. 2001; Sathaye and Bouille 2001; Kumar et al., 2002; Pandey, 2002; Mathew et al., 2005; Jaber et al., 2005). A number of energy efficiency measures are not undertaken although they do not have significant costs. This is because the reduction in energy use is seen as negative in the context of economic growth (Sørensen, 1999). As a result, measures at the supply side that entail a higher cost per energy unit than that of suitable demand-side measures have been implemented. An obstacle in the bottom-up approach is the need for the quantification of energy saving potential at the power generation planning level. This is hardly possible due to lack of available data. Estimating uncertainty in energy savings projects has been described in various publications (ASHRAE, 2002; Reddy et al.,

1999; Jaber et al., 2005). Even if it is statistically quantified, realising such potential is another challenge.

Considering the long-term benefits of the bottom-up approach, more efforts could be taken to adopt energy efficiency measures through effective policy measures and instruments. Implementing policies with a mixture of financial incentives and disincentives, direct investment in energy efficient technology, R&D, legislative measures and institutional frame-works would promote energy efficiency measures. The policies are the key to implement such measures. The acceptability of policy measures can be improved when the environmental and economic implications of alternative measures are shown in juxtaposition. Nonetheless, the bottom-up approach alone cannot ensure adequate power supply or solve the overall problems.

2.5. Integrated top-down and bottom-up approaches

Both the top-down and the bottom-up approaches have their advantages and shortcomings (see Table 2.1). Neither approach by itself can be the ultimate solution in addressing the current energy-environmental issues. A sustainable power supply implies deployment of clean and renewable energy technologies and the implementation of energy efficiency measures. Integrating the top-down and bottom-up approaches in power generation planning would provide better long-term results (see Figure 2.3). Policy analysis can be significantly increased by incorporating bottom-up technology description in top-down approach (Böhringer, 1998). Frei et al. (2003) proposed a dynamic top-down and bottom-up merging model for the investment allocation. Müller (2000) and Pandey (2002) also discussed the integrated approaches. Though Böhringer (1998), Frei et al. (2003), Müller (2000) and Pandey (2002) proposed the integrated approach, they were all focused on the economic or investment perspective of the energy sector. The least cost planning, integrated resource planning,

Table 2.1. Strengths and weakness in top-down and bottom-up approaches

Top-down approach
<p>Strengths</p> <ul style="list-style-type: none"> • Widely used approach. Strategies and instruments are well established. • Less data intensive (economic data or aggregated energy data). It involves relatively simple model analysis. • Less uncertainty to ensure power supply to cope with economic growth, because adequate capacity addition can be done easily. • Impact can be observed in the short term. It is presumed to be a successful approach as it plays a key role in GHG mitigation measures. • Market regulation is easier through simple (command and control) pricing mechanisms. • Intensive R&D and investment make it the most mature methodology in energy planning. <p>Weaknesses</p> <ul style="list-style-type: none"> • Capital intensive in nature and high cost of power supply. Often not a cost effective option. • Often driven by financial and fiscal incentives. Therefore, self-sustainability is uncertain. • Long-term environmental sustainability is uncertain. • Demand side control is difficult, as it hardly incorporates any technical detail on the demand.
Bottom-up approach
<p>Strengths</p> <ul style="list-style-type: none"> • Effective regardless of the energy supply scenario, that would ensure a long-term sustainability. • Offer possibilities for merging and phasing out of technologies. • Simulate market for energy service instead of electricity as a commodity. • Facilitate market driven regulations rather than command and control regulation. <p>Weaknesses</p> <ul style="list-style-type: none"> • Series of transaction barriers prevent the adoption of efficiency measures. Thus it has a low success rate. • Highly data intensive but data is not readily available. • Quantifying the energy saving potential is difficult, making planning difficult. • Difficult to ensure power supply due to uncertainties in identifying energy saving potential and achieving predicted energy saving targets. • Impacts are hardly recognisable in short-terms, thus inspiring less motivation. • Administration intensive in regulation of standards, awareness campaign, monitoring, etc. • Less accepted as the reduction in energy supply is seen as negative in the context of economic growth. • Lack of R&D and investment in energy efficiency.

Fig. 2.3. Integrated approaches of power generation planning

rational planning techniques are also an integrated approach but they are also primarily aimed at cost savings and used for emission mitigation studies. But in addressing the current energy-environmental issues, we must go beyond the economics. This needs a strong evaluation tool that must take into account the long-term implication of the various power generation options available. Such an evaluation tool can be made effective by using the life cycle concept. The life cycle concept is a cradle-to-grave approach to analyse an energy system in its entire life cycle. It can be used as an evaluation tool to integrate the top-down and bottom-up approaches.

2.6. Life cycle assessment

Modern technologies exhibiting good characteristics in the user phase lead to higher absolute environmental impacts in the production phase because of the use of more sophisticated materials and component. However, conventional site-specific impact assessment techniques do not recognise the full range of environmental impacts and do not provide a complete picture of the entire environmental implications. Hence, investigation on the complete lifecycle of the energy system is necessary to ensure that no environmental aspect is neglected. Unfortunately, in many debates on energy systems, the impacts of entire energy systems are not considered and the reliability of energy supply is often neglected (Gagnon et al., 2002). Life cycle assessment (LCA) is recognised as a good tool to evaluate energy systems (Nieuwlaar et al., 1996). However, there have only been conceptual proposals to integrate LCA in energy projects with other types of technology analyses or evaluations (Risø National Laboratory, 2002). The next sub-sections provide definitions and procedure of LCA, LCA studies in power sector and limitations of LCA.

2.6.1. LCA definitions

'LCA is a process to evaluate the environmental burdens associated with a product, process, or activity by identifying and quantifying energy and materials used and wastes released to the environment. The assessment includes the entire life cycle of the product, process or activity, encompassing extracting and processing raw materials; manufacturing, transportation and distribution; use, re-use, maintenance; recycling, and final disposal' (SETAC, 1993). ISO (1997) defines LCA as 'compilation and evaluation of the inputs, outputs and the potential environmental impacts of a product system throughout its life cycle' while the life cycle is defined as

‘consecutive and interlinked stages of a product system, from raw material acquisition or generation of natural resources to the final disposal’.

2.6.2. LCA methodology

LCA methodology undergoes constant change and is evolution driven by new understanding and more refined concepts. Curran (1996) and Pedersen (1997) provided a chronological development and use of LCA. Typically, LCA procedure consists of four major steps, namely, goal and scope definition, life cycle inventory (LCI), impact assessment and improvement assessment (SETAC, 1993; 1998; Boguski et al., 1996; Wenzel et al., 1997; ISO, 1997; 1998; 2000).

2.6.2.1. Goal and scope definition

It defines the product to be studied and states the intended use/purpose and the intended audience. Depending upon its intention, consideration is limited to a few main elements of the product or may be extended to various secondary systems and elements. The system boundaries are defined accordingly.

2.6.2.2. Life cycle inventory

In life cycle inventory (LCI), an input/output material balance is prepared for each phase of the life cycle of each component of the system being studied. The inputs must be traced back to resource consumptions and the outputs must be tied to the projected impacts on the emissions. In establishing the inventory, the product’s life is distinguished in four phases, namely, raw material extraction/ material production, manufacturing, usage and disposal (Bey and Lenau, 1998). The transport between these phases are either distributed within the phases or summarised separately. LCI centres on material and energy balances for each operation within the system for the whole life cycle of the system itself (Boguski et al., 1996).

Wenzel et al. (1997) described the MECO (Materials, Energy, Chemicals and Others) principle used to structure the LCA work. Material, energy and chemicals represent all terminal inputs to the product system. All terminal outputs are caused directly or indirectly by elements from one of these three groups. Material consumption represents one type of resource consumption, typically reversible consumption. Energy consumption represents another kind of resource consumption, typically irreversible. Together, M and E represent all resource consumption in the system. The energy consumption represents a group of impact categories due to the emission from combustion process. Consumption of chemicals represents another group of impact category. Together E and C represent the major part of the environmental impacts arising in the system. The group 'Others' covers impact on working environment that are not covered by M, E and C.

2.6.2.3. Impact assessment

The LCI produces large quantities of complex information on natural resource use and releases to the environment. It is difficult to determine whether 3 kg of CO₂ output are more harmful than 1 g of radioactive waste, since the exact behaviour of the outputs in the environment is rarely known. Thus a common expression, potential impact or impact potential, is used to express the emissions. The LCI data are combined into impact categories like ozone depletion, global warming, photochemical smog, etc, using a conversion factor. The impact assessments do not yield an actual environmental impact. They yield impact surrogates, such as tonne of CO₂ equivalent, which can be useful for a relative analysis or comparison (Wenzel et al., 1997). SETAC and EPA have developed a conceptual framework for impact assessment, which is described in a simplified form by Boguski et al. (1996).

2.6.2.4. *Improvement assessment*

Improvement assessment has always been a part of LCA studies. It ensures that improvement strategies would not lead to undesirable impacts. The desire to reduce the environmental burden by altering a product is often the driver for a LCA study. Another driver for LCA studies is the desire to benchmark a product against their alternatives or to prove that one product is environmentally preferable to another. Improvements are not static accomplishments, but are continually responding to changes in the system being evaluated and its environment.

2.6.2.5. *Streamlined LCA*

The LCA procedure need not be a linear step-wise process. The environmental benefits can be realised in each step. LCI alone can be used to identify opportunities for reducing energy and material usage and emissions. Lewis (1996) reported that in a LCA, it is not necessary to collect data on all inputs and outputs at every stage of the life cycle. LCA can also concentrate on a particular issue that is known to be particularly important in the life cycle of a product. Based on the study by Boguski et al. (1996), LCI can be used directly to perform improvement assessments if impact assessment is not performed.

2.6.3. *LCA in power generation*

Numerous LCA studies have been carried out for products and processes. Norris and Notten (2002) provided a status of worldwide LCA activities. It was observed that the majority of LCA studies are performed in Europe and USA although the application of LCA is gradually increasing in Asian countries. The National Renewable Energy Laboratory (NREL), US Department of Energy conducted a number of LCA studies on electricity production from biomass (Mann and Spath, 1997; Spath and Man, 2000a), coal (Spath et al., 1999) and natural gas (Spath and Mann, 2000).

These studies were performed in order to examine the environmental aspects of current and future systems and technologies. They were also aimed to use LCA to compare various electricity generation systems.

In Switzerland, LCA was carried out to study the implication of electricity production from biogas from farm wastes (Edelmann et al., 2002).

In GEMIS (2002), LCI database is established for various energy generating systems.

Schleisner and Nielsen (1997) performed LCA of wind energy, biogas and natural gas. Their study analysed the environmental externalities (working environment) such as visual amenity, noise, accidents, impacts on birds, atmospheric emissions and GHG. They concluded that externalities may be used for the optimisation of plant site selection or for choosing different energy alternatives. It highlighted the need for inclusion of cost analysis that will help to prioritise the environmental friendly technologies.

Gagnon et al. (2002) conducted a comparison of electricity generation from few different systems. This was aimed to assist policy makers in decision-making. Comparisons were made between the alternate energy options for electricity generation.

In India, a LCA for three renewable energy systems, namely, solar water heater, solar PV and wind power was carried out by Mathur et al. (2002). A correlation between the energy yield ratio (equivalent to specific energy consumed to produce unit energy output from the system) and specific emissions was made. However, the economic implications of those system were not studied.

Lee et al. (2004) had established a LCI for Korean power sector. However, only the up-stream processes of the fuel production were included in their LCA boundary. They accounted for about 5 % of the total CO₂ emissions in oil and natural gas-fired plants. Though NO_x, SO_x and PM were included in the LCI, CH₄ was not included.

Based on website information, a life cycle inventory for electricity grid mix in Japan was found to be carried out by the National Institute for Resource and Environment, Japan. However, no publications were found from this research. Additionally, the Institute of Energy Economics carried out a life cycle inventory analysis of fossil energies in Japan (Yoon and Yamada, 2002).

A project on LCA for electricity grid mixes of Thailand was launched in September 2000 (Thai Environmental Institute, 2002). It was aimed to establish an LCA database and Life Cycle Impact Assessment methodologies applicable to APEC member economies. However, no further details were found.

Numerous LCA studies have been carried out for solar PV system and the energy use is commonly expressed in energy payback time (EPBT) (Hagedorn, 1989; Phylipsen and Alsema, 1995; Nieuwlaar et al., 1996; Kato et al., 1997; Corkish, 1997; GEMIS, 2002; Karl and Theresa, 2002; Gagnon et al., 2002). EPBT is the time required for the solar PV module to generate the equivalent amount of energy consumed in its manufacturing processes. A wide variation in the EPBT is found in these studies. The variation can be attributed to technological assumptions and system boundary.

From the reviews, it was observed that the upstream processes of electricity production contributed significantly to total emissions and energy use. However, they were not comparable due to wide variations in their boundaries and assumptions.

Though many LCA studies are found for the electricity generations, hardly any LCA studies was found on energy efficiency options, the bottom-up approach.

2.6.4. Limitations of LCA

There is a general reluctance to use LCA because of concerns about its methodology. Problems include the definition of system boundaries, the accuracy of data and inadequate information about environmental impacts. Demmers and Lewis (1996) mentioned that LCA will never be entirely accurate or value-free because of concerns about methodology, system boundaries and assumptions although it can highlight environmental problems and areas for potential improvement.

LCA tends to be very data intensive. For this reason the value and credibility of any LCA will depend on the quality of its data. Though the number of LCAs being undertaken has increased, many of these studies have been criticised because of concerns about their data (Lewis, 1996). Pedersen (1997) and Goldberg (1992) provided a few examples of LCA studies, which reached contradictory conclusions about similar products. Thus exact comparisons may not be possible using LCA. Nevertheless, it is expected to generate better insights if the LCA is carried out for a common objective and, of course, with uniform system boundaries.

2.7. Life cycle cost analysis

Economic feasibility is a prime criterion in decision-making on power generation, especially in the current deregulated electricity market. LCA does not account for the economic implications (ISO, 1997). Therefore, there is a need to include cost analysis into a LCA. Life cycle cost analysis (LCCA) is an economics analysis tool that significantly provides a better assessment of the long-term cost effectiveness of a project. LCCA is merely a means to recognise that capital cost alone

is not enough to fully evaluate an energy system, but all costs incurred over the life cycle of the system must be considered. The 'life cycle cost of an item is the sum of all funds expended in support of the item from its conception and fabrication through its operation to the end of its useful life' (White and Ostwald, 1976; Woodward, 1997). Thus, LCCA can facilitate identification of the most cost effective alternative and enable investment options to be more effectively evaluated by considering the impact of all costs rather than only the initial costs. However, LCCA does not account for any potential environment impact of such alternatives. LCCA is an established tool (Woodward, 1997) and the review by Glucha and Baumannb (2004) shows that much efforts were made on developing LCC oriented environmental accounting tools among researchers. Some methods have different names, but similar principles in their algorithm; others have the same name, but different principles for the calculation. Glucha and Baumannb (2004) also summarised the pros and cons of those LCC techniques and uncertainties. However, those uncertainties are very hard to account though they are important to be considered.

2.8. Exergy analysis in LCA

When energy is used, its *quality* decreases due to irreversibility, i.e. entropy generation. However, the first law of thermodynamics does not reveal how the quality of energy is utilised. The quality of energy is articulated as exergy⁶, which is the capacity for doing work or causing changes (Kotas, 1985). Exergy is exempted from conservation and is based on the law of degradation. Therefore, exergy analysis would give a different perspective on energy *utilisation*.

⁶ Exergy is the total amount of free energies in a system or shaft work/electrical energy necessary to produce a material in the specified stage from material common in the environment in a reversible way (Szargut et al., 1988). Ahern (1980) defined exergy as available work in a gas, fluid or mass as a result of its non-equilibrium condition with its surrounding environment.

In LCA, primary energy uses are quantified based on energy balance. It does not look into the details of how the energy is *utilised*. Hence, inclusion of exergy analysis in LCA can generate insights on resource utilisation. Szargut et al. (1988) introduced the concept of cumulative exergy consumption (CExC), which is the sum of the exergies of natural resources consumed in all steps of a production process. In recent years, exergy analysis has been included in LCA (Finnveden and Oestlund, 1997; Cornelissen and Hirs, 2002; Wall, 2002; Lombardi, 2001; 2003). It is also referred to as exergetic life cycle analysis (ELCA) (Cornelissen and Hirs, 2002) and life cycle exergy analysis (LCEA) (Wall, 2002). Exergy analysis in LCA can provide an unambiguous understanding of the consumption activities within the life cycle and insights into potential exergy savings at the process and system levels (Vigon, 1999).

2.8.1. Exergy analysis

Like energy, exergy (B) is also divided into distinct components, kinetic exergy (B_k), potential exergy (B_p), physical exergy (B_{ph}) and chemical exergy (B_o). Physical and chemical energies are more relevant to combustion and heat transfer processes. Physical exergy is defined by Kotas (1985) as

$$B_{ph} = C_p (T - T_o) - T_o [C_p \ln(T/T_o) - R \ln(P/P_o)] \quad (2.1)$$

where the first term is energy content while the second term is irreversibility. C_p is the specific heat at constant pressure. T and P refer to temperature and pressure, respectively and subscript 'o' refers to the reference environment.

The chemical exergy of fuel is more relevant in relation to the heating value of fuel. Szargut et al. (1988) established a ratio between chemical exergy and heating value of various fuels, which is given by

$$\beta = b_{ch}/C_l \text{ or } \beta = b_{ch}/C_F, \quad (2.2)$$

where b_{ch} is the chemical exergy of fuel. C_l and C_F are the lower and higher heating values of fuel.

Equation (2.2) is widely adopted by many researchers (Kotas, 1985; Finnveden and Oestlund, 1997; Wall, 2002; Cornelissen and Hirs, 2002; Lombardi, 2001: 2003; Taniguchi et al., 2005). The value of β for fossil fuels such as fuel oil and coal, is in the range of 1.04 - 1.17 (Finnveden and Oestlund, 1997). It can be seen that there is not much difference between the chemical exergy and energy content of fuels. In contradiction, Barclay (2003) showed that chemical exergy for any fuel is roughly 2.5 times that of the heating value.

2.8.2. Methodologies for exergy analysis in LCA

The framework of the ELCA and LCA are quite similar and the goal definition and scope are completely identical. The inventory analysis of the ELCA is more elaborate. Complete flow sheets of the mass and energy streams of the different production steps are needed. The material and energy balances have to be closed. The more simplified black-box approach could be used of which only the inputs and outputs of the production processes are taken into account. The impact assessment is limited to calculation of the exergy of the flows and the determination of the exergy destruction in the different production processes. The sum of all exergy destruction in the life cycle gives the life-cycle irreversibility of the product (Cornelissen, 2004a).

Although the LCA and ELCA are similar in nature, there is no specific framework on how to account (characterise) exergy in the ELCA. It is unclear whether the exergy of fuel and non-fuel substances or renewable and non-renewable resources should be accounted separately or together as a single resource. In Lombardi (2001;

2003)'s works, exergy of fossil fuel was accounted and the renewable fuel was ignored. Wall (2002) accounted for the exergy of renewable and non-renewable energy sources separately. Cornelissen and Hirs (2002) combined exergy of fuel, non-fuel materials, renewable and non-renewable fuels. However, it is inappropriate to add exergies of fuels and non-fuel substance, renewable and non-renewable sources because it would be difficult to distinguish between scarce and abundant reserves. Therefore, they should be characterised. Finnveden and Oestlund (1997) concluded that exergy consumption may be used as a characterisation method in LCA. Non-fuel substance, e.g., metals, can be easily accounted based on their mass rather than their exergy. Exergy of metal ore is negligible compared to exergy of fuel required for its production (Finnveden and Oestlund, 1997). Therefore, considering exergy of the energy stream would be adequate and the exergy of non-fuel substances can be ignored.

The study by Lombardi (2003) revealed that exergy destruction in the construction and the decommissioning phases of fossil fuel based power generation system is negligible. The highest exergy destruction occurred in the operational phase and the second largest losses occurred in the upstream process of fuel production. It resembled the trend of a typical LCA, wherein the primary energy use is highest in the operational phase followed by the upstream process (see Section 4.2.2). Therefore, accounting for only exergy of fuel and its upstream process could be a good approximation to a comprehensive ELCA. In Chapter 6, the significance of exergy analyses is described with some examples to show its importance in the integrated top-down and bottom-up approaches. In those examples, only the exergy of fossil fuels and their upstream process are accounted.

2.9. Summary

The supply based top-down and energy efficiency based bottom-up approaches have their own strengths and weaknesses. The former is seen as uneconomical but easy to execute whereas the latter is cost effective but with barriers in execution. Therefore neither the top-down nor the bottom-up approach by itself can be the ultimate solution in addressing the current energy-environmental issues. Thus the integrated the top-down and bottom-up approach is proposed with LCA and LCCA as appraisal tools. LCA is an effective tool to pinpoint the environmental implications but it fails to account for economic implications. On the other hand, LCCA provides effective evaluation to pinpoint cost effective alternatives but it does not account for any potential impact such alternatives may have on the environment. Therefore, the combined use of LCA and LCCA would point out the options with the greatest potential for cost-effective power supply and emission reductions. Exergy analysis relevance to this study is also reviewed. They show that inclusion of exergy analysis in LCA could provide additional information on energy resources unitisation.

3. Research Methodology

3.1. Introduction

This chapter describes the methodologies used in this research. The procedure for carrying out the LCA-LCCA and equations used in the model for the estimation of life cycle energy use, GWP and cost are presented. The logical framework on the integration of the top-down and bottom-up approaches is described.

3.2. Life cycle assessment (LCA)

The conventional four-step LCA procedure is used for this research. The goal of the LCA is to quantify the non-renewable (fossil) primary energy use and GWP in producing electricity or providing energy services such as cooling and heating. An appropriate functional unit is chosen and life cycle system boundaries are defined. The life cycle of an energy system is considered in three phases, namely, construction, operation and decommissioning. In the construction phase, production of plant equipment and accessories, and on-site construction are included. In the operational phase, the material inflow during the operational lifetime is accounted. In the decommissioning phase, the demolition of the energy systems, disposal and recycling of material are included.

3.2.1. Material inventory

For life cycle inventory, the MECO structure of Wenzel et al. (1997) is used (see Section 2.6.2.2). Firstly, an inventory on material inflow and outflow is prepared for the three-life cycle phases and a material balance is established. Since this research is primarily focused on non-renewable (fossil) energy use, other than fossil energy use, no other resources consumption, e.g. metal ore or water are considered. However, to account for primary energy uses associated with other resources, these are included in

the material inventory. In terms of material balance, material inflow in the construction phase is balanced by the material outflow in the decommissioning phase. The fuel inflow in the operational phase is balanced by exhaust gas emissions while the water inflow is balanced by leakages, discharged wastewater, and lost through evaporation. For material recycling and disposal, case-specific scenarios are used and they are described in each case study.

3.2.2. Life cycle energy use calculation

The materials in the material inventory are traced back to their origins, and their primary (non-renewable/fossil) energy consumptions are estimated based on their specific energy consumption [Equation (3.1)].

$$\text{Energy}(j)_i = m_i \times \text{Specific Energy}(j)_i \quad (3.1)$$

where $\text{Energy}(j)_i$ is energy consumed for i^{th} material in j^{th} processes (extraction, processing, recycling, etc.) and m_i is mass of the i^{th} material used/consumed in the energy system. $\text{Specific Energy}(j)_i$ is energy required to produce or process unity quantity of i^{th} material in the j^{th} process.

Energy used in each life cycle phase is estimated as the sum of the direct energy consumed and the sum of the energies used for all materials associated to that phase. For example, Equation (3.2) gives the energy use for the construction phase.

$$\text{Energy}_{\text{Construction}} = \left(\begin{aligned} &\text{Energy}(C) + \sum_{i=1}^n \text{Energy}(E - E)_i \\ &+ \sum_{i=1}^n \text{Energy}(P - M)_i \end{aligned} \right) \quad (3.2)$$

where Energy(C) is direct energy used in construction phase, Energy(E-E)_i is energy consumed for exploration and extraction of i^{th} material, Energy(P-M)_i is energy use for processing and/or manufacturing of i^{th} material.

Similarly, energy used in the operational and decommissioning phases are given in Equations (3.3) and (3.4). In the operational phase, some materials (especially fuels) have their embedded energy that would be released in combustion. They are added in the energy inventory as fuel energy, Energy(F).

$$\text{Energy}_{\text{Operation}} = \left(\begin{array}{l} \text{Energy(O)} + \sum_{i=1}^n \text{Energy(E - E)}_i \\ + \sum_{i=1}^n \text{Energy(P - M)}_i + \sum_{i=1}^n \text{Energy(F)}_i \end{array} \right) \quad (3.3)$$

$$\text{Energy}_{\text{Decommissioning}} = \left(\begin{array}{l} \text{Energy(D - D)}_i + \sum_{i=1}^n \text{Energy(R}_{\text{cycle}})_i \\ - \sum_{i=1}^n \text{Energy(R}_{\text{use}})_i \end{array} \right) \quad (3.4)$$

where Energy(O) is direct energy used in operational phase, Energy(F)_i is fuel embedded energy in i^{th} material, Energy(D-D)_i is direct energy use in decommissioning-disposal phase, Energy(R_{cycle})_i is energy use in recycling of i^{th} materials, Energy(R_{use})_i is energy to be saved from the reuse of i^{th} material. Energy(R_{use})_i is equivalent to be the sum of Energy(E-E)_i and Energy(P-M)_i.

Transportation energy is estimated as the sum of energy used for transporting all the materials associated with the energy system, see Equations (3.5) and (3.6).

$$\text{Energy}_{\text{Transportation}} = \sum_{i=1}^n \text{Energy(T)}_i, \quad (3.5)$$

where $\text{Energy}(T)_i$ is energy consumption in transportation of i^{th} material.

$$\text{Energy}(T)_i = m_i \times \text{transportation distance} \times \text{Sp. transportation energy} \quad (3.6)$$

where m_i is the mass of i^{th} material transported. The specific transportation energy is the energy required to transport one tonne of material for one-kilometre (MJ/t-km), which varies with the mode of transportation (e.g. ship, pipeline, road, etc.). If the material is transported by more than one mode of transportation then each mode of transportation is estimated separately and summed up. For example, in a case of fuel oil used in power plant, firstly cured oil is transported from the oil field to refinery by tankers and then fuel oil from refinery to power plant by pipeline.

Life cycle energy use is estimated as the sum of the energies consumed in the three life cycle phases and in transportation [Equation (3.7)]. Thus the life cycle energy use includes the energy consumed in exploration, extraction, processing, manufacturing, decommissioning and disposal of all the materials associated with the energy system. From the life cycle energy use, energy use per functional unit is calculated. Life cycle energy use is also referred to as cumulated energy requirement (Mathur et al., 2002) and cumulative energy demand (GEMIS, 2002).

$$\text{Life cycle energy use} = \begin{pmatrix} \text{Energy}_{\text{Construction}} \\ + \text{Energy}_{\text{Operation}} \\ + \text{Energy}_{\text{Decommissioning}} \\ + \text{Energy}_{\text{Transportation}} \end{pmatrix} \quad (3.7)$$

3.2.3. Life cycle GWP

To calculate GWP, three major GHG, namely, CO_2 , CH_4 and N_2O , are estimated. The energy use are traced back to their primary sources and GHG emissions are estimated based on their specific emission factors using Equation (3.8). However,

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the primary sources of energy is often unknown for the energy consumed in some processes like, the manufacturing of plant equipment, recycling of the metals. For such unknown sources of primary energy, an average CO₂ emission factor of coal, oil and gas is used (van Margreet et al., 1994). However, CH₄ and N₂O are ignored in such cases due to uncertainty and their insignificant nature.

$$\text{Emission } (k)_j = (\text{Primary energy use})_j \times \text{Sp. emission factor of } k, \quad (3.8)$$

where Emission $(k)_j$ is the emission of pollutant k (e.g. CO₂, CH₄ or N₂O) from primary energy use in j^{th} process/activities.

In addition to energy related emissions, direct release of GHG is also estimated, e.g. leakage of gases, venting of refrigerants. Then the total emission of pollutant k from each life cycle phase is estimated as the sum of energy related emission and direct emissions. Equation (3.9) shows the emission for the construction phase.

$$\text{Emission } (k)_{\text{construction}} = \sum_{j=1}^n \text{Emission } (k)_j + \sum_{j=1}^n \text{Direct emission } (k)_j \quad (3.9)$$

The life cycle emission of pollutant k is estimated as the sum of its emissions in the three life cycle phases and in transportation [see Equation (3.10)].

$$\text{Life cycle emission } (k) = \begin{pmatrix} \text{Emission } (k)_{\text{Construction}} \\ + \text{Emission } (k)_{\text{Operation}} \\ + \text{Emission } (k)_{\text{Decommissioning}} \\ + \text{Emission } (k)_{\text{Transportation}} \end{pmatrix} \quad (3.10)$$

The three GHG emissions are estimated separately. It is inappropriate to compare them on their mass basis because their impact on global warming is not uniform. Thus they are classified under global warming category and the GWP per

functional unit is calculated in CO₂ equivalents. The GWP of CH₄ and N₂O are considered as 21 and 310 times of CO₂, respectively in a 100-year time horizon (IPCC, 1996a).

3.2.4. Sensitivity analyses

Sensitivity analyses are carried out to ascertain the effectiveness and uncertainties of assumptions made and data used. It is also aimed to find the key factors (variables) influencing the life cycle energy use and GHG emissions. To compare the magnitude of the variations in the sensitivity analyses, a base case (reference) is fixed. In selected case studies, the variations are generalised and some correlations are established. The sensitivity analyses also lead to some scenario studies to find potential reduction in fossil energy use and GWP, which are likely to be the improvement analysis of a typical LCA procedure.

3.3. Life cycle cost analysis (LCCA)

In LCCA, costs are categorised into three categories, like the three phases in the LCA. The costs involved in the construction phase are considered as capital cost, which includes the initial capital expenses for system design, engineering, equipment, installation and testing. The capital cost is distributed over its service (technical) lifetime of n years using the capital recovery factor from Thumann (1998). Different kinds of lifetime can be considered for LCC, e.g. functional-, physical-, technological-, economic- and social and legal-, utility lifetimes⁷ (Woodward, 1997; Glucha and

⁷ Functional life is the period over which the need for the asset is anticipated. Physical life is the period over which the asset may be expected to last physically, to when replacement or major rehabilitation is physically required. Technological life is the period until technical obsolescence dictates replacement due to the development for technological superior alternatives, economic life is the period until economic obsolescence dictates replacement with a lower cost alternatives, social and legal life is the period until human desire or legal requirement dictates replacement (Woodward, 1997). Utility life is the estimated time the system can satisfy established performance standards (Glucha and Baumannb, 2004).

Baumannb, 2004). For this study, technical lifetime is used because this LCCA is aimed to estimate the bare minimum cost of the service rather than its profitability.

The capital cost is assumed to be incurred at the beginning (a single payment at zero year) of the project even though the construction of power plant often takes many years. Equation (3.11) shows the capital cost component of the LCCA, in which the capital cost P is accounted with an annual interest rate (i) payable over its life time of n years.

$$\text{Capital cost} = Pn \left[\frac{i(1+i)^n}{(1+i)^n - 1} \right] \quad (3.11)$$

Major costs that occur during the operational phase are categorised as O & M ($C_{O\&M}$) and energy costs (C_E). In selected case studies, the O & M costs are sub-categorised as fixed- and variable O & M costs. The fixed O & M cost includes the cost involved in scheduled maintenance, land lease, human resources, inspections, insurance, electrical demand cost, etc. while the variable O & M costs include the consumables, fuel, etc. However, the energy/fuel costs are accounted separately (C_E). As all these costs occur over the entire operational lifetime, they are projected with an escalation rate (e). Then they are reduced to their present value using discounting techniques. The discount rate (d) reflects either the effect of the real earning power of money invested over time or the effects of inflation. Using the gradient present worth factor (Thumann, 1998), O & M and energy costs are accounted in the LCCA. Equation (3.12) shows the component of operational phase cost in the LCCA model. In this model, provisions are made to consider different escalation rates for the O & M cost and fuel price.

$$\text{Operational costs} = (c_E + c_{O\&M}) \left[\frac{\frac{1+e}{1+d} \left(1 - \left[\frac{1+e}{1+d} \right]^n \right)}{1 - \frac{1+e}{1+d}} \right], \quad (3.12)$$

In the operational phase, in addition to the O & M and energy costs, other costs may be anticipated on replacement of spares. Often, such costs could have been included in the O & M costs. However, in this model, provisions are made to account for replacement costs C_{R_r} that may occur on r^{th} year during the lifetime of n years. Such costs are accounted by a present worth factor (Thumann, 1998) using a discount rate (d) as in Equation (3.13).

$$\text{Replacement costs} = \sum_{r=1}^n C_{R_r} \left[\frac{1}{(1+d)^r} \right], \quad (3.13)$$

In the decommissioning phase, costs are incurred in demolition, scrapping and disposal of the system ($C_{D\&D}$) while the equipment can have some salvage (resale) value (L). In LCCA, the net cost occurred in the decommissioning phase is discounted to the present value using a discount rate (d). Equation (3.14) shows the decommissioning cost component of the LCCA.

$$\text{Decommissioning costs} = (C_{D\&D} - L) \left[\frac{1}{(1+d)^n} \right] \quad (3.14)$$

The life cycle cost (LCC) is estimated as the sum of the costs involved in the three life cycle phases, i.e. capital, operational and decommissioning. Equation (3.15) is used for the calculation of life cycle costs. From the life cycle cost, the cost per functional unit is calculated.

$$LCC = \left(Pn \left[\frac{i(1+i)^n}{(1+i)^n - 1} \right] + (c_E + c_{O\&M}) \left[\frac{\frac{1+e}{1+d} \left(1 - \left[\frac{1+e}{1+d} \right]^n \right)}{1 - \frac{1+e}{1+d}} \right] + \sum_{r=1}^n C_{R_r} \left[\frac{1}{(1+d)^r} \right] + (C_{D\&D} - L) \left[\frac{1}{(1+d)^n} \right] \right) \quad (3.15)$$

3.3.1. Components with varying lifetimes

Often in energy projects, the system components could have different lifetimes. For example, in district cooling service, the pipeline network has a service life of 60 years while chillers have 20 years. Hence, a repeated investment occurs for chillers so as to utilise the full capital costs of the pipeline network. In such cases, the LCC can be calculated using Equation (3.15), wherein the repeated investment is to be treated as replacement cost. However, in some cases, the repeated capital costs are huge and they may come from loan or other sources bound by interest. Under such circumstances, Equation (3.15) underestimates the life cycle cost. Hence an additional term is included in Equation (3.15). Let the repeated capital costs (P_{r_r}) carrying an annual interest rate (i) occurring every r^{th} year and the equipment would have a lifetime of n_r years ($n_r < n$). For LCC, P_{r_r} is distributed over its service lifetime of n_r years from the r^{th} year to $(r+n_r)^{\text{th}}$ years using the capital recovery factor. Then they are discounted to the present value using the discounting technique. The new LCC equation is shown as Equation (3.15a).

$$LCC = \left(Pn \left[\frac{i(1+i)^n}{(1+i)^n - 1} \right] + \sum_{r=1}^n P_{R_r} \left[\frac{i(1+i)^{n_r}}{(1+i)^{n_r} - 1} \right] \left[\frac{(1+d)^{n_r} - 1}{d(1+d)^{r+n_r}} \right] \right. \\ \left. + (c_E + c_{O\&M}) \left[\frac{\frac{1+e}{1+d} \left(1 - \left[\frac{1+e}{1+d} \right]^n \right)}{1 - \frac{1+e}{1+d}} \right] + \sum_{r=1}^n C_{R_r} \left[\frac{1}{(1+d)^r} \right] \right. \\ \left. + (C_{D\&D} - L) \left[\frac{1}{(1+d)^n} \right] \right) \quad (3.15a)$$

3.3.2. Sensitivity analysis

LCC is highly dependent on the assumptions and estimates in the cost data. Even if quality data is available there is always an element of uncertainty⁸ associated with these estimates and assumptions. For example, in the discounting technique, the discount rate reflects either the effect of the real earning power of money invested over time or the effects of inflation. Selection of a suitable discount rate is crucial, as a higher discount rate would tend to favour low capital cost, short life and high recurring cost, whilst a low discount rate will have the reverse effects. Hence sensitivity analyses are carried out for the critical cost and cost scenarios are developed.

All the cost data quoted in the LCCA are in Singapore Dollars (S\$) (US\$ 1 = approx. S\$ 1.6333 as at February 2005).

3.4. The bottom-up approach

LCA and LCCA of the power generation technologies in the top-down approach are quite straightforward. However, the framework to perform LCA-LCCA in the bottom-up approach is more complex. The first task in the bottom-up model is to

⁸ The uncertainties include the difference between the actual and expected performance, change in operational assumption arising from modification in user activities, future technological advance that could provide lower cost alternatives and hence shorten the economic life of the system, change in price level of major resource energy or man power, selecting the discount rate, etc.

identify technically feasible measures or service that would save electricity or serve as an alternative to electricity. This requires exhaustive information at the demand side, such as electricity utilisation pattern, its end-use application, technologies in use, etc. and supply side. A decomposition method can be used to identify and quantify the potential for energy efficiency.

3.4.1. Decomposition analysis

The national total electricity supply and demand are denoted⁹ by Q_s and Q_d . Q_s is generated from m number of technologies in the top-down model to meet the electricity demand Q_d as illustrated in Figure 3.1

$$Q_s = \sum_{i=1}^m q_i \quad (3.16)$$

$$Q_s = Q_d + Q_{T\&D} \quad (3.17)$$

where q_i is the quantity of electricity generated from the i^{th} energy sources/technologies. $Q_{T\&D}$ is the T&D losses, which is assumed to be zero for the distributed power generation technologies (DG).

The total electricity demand (Q_d) is decomposed into sectoral use, end-use applications/service and technology use as shown in Figure 3.2. The electricity demand (q_{x_u}) in the u^{th} sector is given by

$$q_{x_u} = Q_d p_{x_u} \quad (3.18)$$

⁹ The terms “electricity demand” and “electricity consumption” are used interchangeably with the same meaning and depending upon the context of the text.

where p_{x_u} is the percentage of electricity consumed in the u^{th} sector for $u = 1$ to n , e.g. industrial, domestic and commercial. For example, in Singapore, share of electricity consumption in commercial sector is about 38 % (EMA, 2004c). If $u = 2$ represents the commercial sector, then $p_{x_2} = 38\%$ (see Figure 3.2).

Fig. 3.1. Power generation in top-down model

The sum of electricity consumption in all the sectors is the total electricity demand.

$$Q_d = \sum_{u=1}^n q_{x_u} \quad (3.19)$$

The sectoral level electricity consumption q_{x_u} is decomposed based on their service/end-use applications viz. lighting, cooling and motive power (see Figure 3.2).

Fig. 3.2. Decomposition of electricity demand for the bottom-up model

$$q_{x_u y_v} = \sum_{u=1}^n q_{x_u} p_{x_u y_v} \quad (3.20)$$

$$Q_d = \sum_{v=1}^n q_{y_v} \quad (3.21)$$

where $q_{x_u y_v}$ is the quantity of electricity consumed for v^{th} service in the u^{th} sector.

$p_{x_u y_v}$ is the percentage of electricity consumed for the v^{th} service in the u^{th} sector, $v = 1$ to n . For example, in Singapore, air-conditioning accounts for about 70 % of the commercial sector's electricity consumption (Jayamaha, 2004). If $v = 3$ and $u = 2$ represent the cooling service and commercial sectors, respectively then $p_{x_2 y_3} = 70 \%$.

From Equations (3.20) and (3.21)

$$Q_d = \sum_{u=1}^n \sum_{v=1}^n q_{x_u} p_{x_u y_v} \quad (3.22)$$

The energy services are further decomposed into technology adopted. For example, split air conditioners and chillers are used for cooling services. Few technologies could also be used across the sectors. For example, electrical motors are used in industrial sector for motive power applications and in commercial/service sectors in cooling services (e.g. in chilled water pumps). The technology-specific decomposition facilitates to introduce the crosscutting technologies, e.g. energy efficiency motors.

$$q_{x_u y_v z_w} = \sum_{v=1}^n q_{x_u y_v} p_{y_v z_w} \quad (3.23)$$

where $q_{x_u y_v z_w}$ is the quantity of electricity consumed in the w^{th} technology for the v^{th} energy services in the u^{th} sector. $p_{y_v z_w}$ is the percentage of electricity consumed by the w^{th} technology in the v^{th} services. For example, if $w = 6$ represents the chiller, then the chillers adopted for cooling service ($v = 3$) in the commercial sector ($u = 2$) is denoted by $q_{x_2 y_3 z_6}$ (see Figure 3.2).

From Equations (3.20) and (3.22)

$$q_{x_u y_v z_w} = \sum_{u=1}^n \sum_{v=1}^n q_{x_u} p_{x_u y_v} p_{y_v z_w} \quad (3.24)$$

Therefore, the total electricity demand is the sum of electricity consumed by all technologies in use.

$$Q_d = \sum_{w=1}^n q_{x_u y_v z_w} \quad (3.25)$$

From Equations (3.24) and (3.25),

$$Q_d = \sum_{u=1}^n \sum_{v=1}^n \sum_{w=1}^n q_{x_u y_v} q_{y_v z_w} P_{x_u y_v z_w} \quad (3.26)$$

The decomposition of the electricity consumption is an effective methodology to identify the potential for the alternative energy service/technology, e.g. DCS, energy efficient motors, etc. Therefore, the decomposed data is a prerequisite to the bottom-up model to quantify the potential for penetration of an alternative technology or service and their effective implementation without which it would be very difficult to cope with the bottom-up model in power generation planning. This is why the bottom-up approach is fraught with great difficulties.

3.4.2. LCA-LCCA of bottom-up approach

When an activity/measure at the bottom-up model is identified, the next step would be to evaluate its energy use, emissions and cost-effectiveness. In the implementation of measures in the bottom-up model, fossil energy use and/or GHG emission could occur from a large-scale adoption of new technologies, retrofitting, disposal of equipment, etc. Direct costs would occur in capital equipment and operation and maintenance (O & M) while indirect cost would occur in programme administration, such as awareness campaign, enforcement of standards, regulation and monitoring (Blumstein et al., 2005). To quantify their life cycle energy use, GWP and

cost, LCA and LCCA should be performed with appropriate functional units. Figure 3.3 shows the LCA and LCCA framework in the bottom-up approach.

Fig. 3.3. Framework for LCA-LCCA in the bottom-up model

3.5. Framework for integrated approach

ΔQ_d is the forecasted additional electricity demand from the base year so that the total demand would be $Q_d + \Delta Q_d$. ΔQ_d can be met either from supply based top-down or energy efficiency based bottom-up approaches. In the top-down approach, ΔQ_d would be generated whereas in the bottom-up approach, an equivalent amount of electricity would be made available from energy efficiency or alternative services. The bottom-up approach would be more sustainable because it would be effective regardless of the power generation scenario. However, the acceptance and adaptation of the bottom-up approach is fraught with uncertainties and barriers due to conventional

(short-term) appraisal techniques and market mechanism. To overcome these transition barriers in the adoption of the bottom-up approach, the integrated approach attempts to use the details from the top-down model.

Instead of comparing the emission and cost effectiveness of the bottom-up model with the 'prevailing' power generations at the top-down model, they should be appraised in conjunction with 'future' power generation options. For example, in implementation of energy efficiency measures, its cost effectiveness is appraised based on the market electricity price. The market electricity prices could be cheaper in the current power generation scenarios that it might hinder the adaptation of the energy efficiency measures. However, they should be compared with future or alternative source of electricity generation, which could be solar PV or wind. Therefore, all power generation options in the top-down approach should be identified and LCA-LCCA should be performed for the appraisal of the bottom-up measures. The integrated approach selects the best options from both the top-down and bottom-up models (see Figure 2.3). It is aimed to find the best generation mix to fulfil the national policy objective. The policy objective can be GHG emission reduction or fuel security or cheaper power supply or a combination of them. Therefore, in power generation planning, the life cycle primary energy use, GWP and cost can be used as indicators on fuel security, environmental protection and economic growth.

A , B and C are the total life cycle primary energy use, GWP and the cost incurred in the power sector to meet the demand Q_d .

$$A = \sum_{i=1}^m a_i q_i \quad (3.27)$$

$$B = \sum_{i=1}^m b_i q_i \quad (3.28)$$

$$C = \sum_{i=1}^m c_i q_i \quad (3.29)$$

where a_i , b_i and c_i are specific life cycle energy use, GWP and cost of electricity generation from the i^{th} energy sources/technologies. q_i is the quantity of electricity generated from the i^{th} energy sources/technologies.

The national averages on the life cycle energy use, GWP and cost can be written as

$$a = \frac{A}{Q_d} \quad (3.30)$$

From Equations (3.17), (3.27) and (3.30),

$$a = \frac{\sum_{i=1}^m a_i q_i}{Q_s - Q_{T\&D}} \quad (3.31)$$

From Equations (3.16) and (3.31),

$$a = \frac{\sum_{i=1}^m a_i q_i}{\sum_{i=1}^m q_i - Q_{T\&D}} \quad (3.32)$$

Similarly,

$$b = \frac{\sum_{i=1}^m b_i q_i}{\sum_{i=1}^m q_i - Q_{T\&D}} \quad (3.33)$$

$$c = \frac{\sum_{i=1}^m c_i q_i}{\sum_{i=1}^m q_i - Q_{T\&D}} \quad (3.34)$$

In the bottom-up measures, the net primary energy saving, emission reduction potential and costs should be estimated (see Section 3.4.2). Sometimes, impacts of measures taken at the power sector would be reflected in the other energy consuming sectors. For example, in cogeneration, the steam can be used to offset the industrial boiler based steam production. In such a case, the measures at the bottom-up model of the power sector would have impacts in industrial sector energy use. Thus, the net effects should be quantified and can be either positive or negative. However, considering the negative values of the net energy saving and emission reduction potential would not be effective. In such a case, the top-down model would be effective.

Power generation scenarios are developed based on the options in the top-down and integrated approaches. For the base year, Q_s^0 is the total quantity of electricity generated and their life cycle primary energy use, GWP and cost are A^0 , B^0 and C^0 , respectively. To meet the electricity demand of the n^{th} year ($Q_d^0 + \sum_{n=1}^m \Delta Q_s^n$), various combinations of technologies from the top-down and bottom-up models are developed. A wide range of power generation mix scenarios are developed and their primary energy use, GWP and cost are estimated as A^n , B^n and C^n . The best option is chosen based on the alternative with minimum level of A , B and C . However, it is often a challenging task to pinpoint the power generation mix with the minimum of A , B and C . Therefore, multi criteria decision-making tools, such as Analytical Hierarchy Process (AHP) and Heuristic Approach, can be used to select the best choice of power generation (also see Section 7.4.8).

The AHP, introduced by Saaty (1980), is known as a pairwise comparison method. It provides a proven, effective means to deal with complex decision making

and can assist with identifying and weighing selection criteria and expediting the decision-making process (Saaty, 1980). There are lot of research on the application of AHP technique for decision-making specific to renewable energy and energy efficiency (Tzeng et al., 1992; Xiaohua and Zhenmin, 2002; Aras et al., 2004; Kablan, 2004). Pohekar and Ramachandran (2004) provided an extensive review on the application of AHP techniques in the energy sector. In multi-criteria decision tools, different weighing factors may be allocated to the different variables. Often multi-disciplinary professional experts would be engaged on evaluation and assessment of weighing factors based on the local relevance.

3.6. Summary

The research methodologies described in this chapter are used for the construction of LCA and LCCA models using Excel spreadsheets. The LCA-LCCA methodologies are used to perform LCA and LCCA for technologies in the top-down model (Chapter 4) and bottom-up models (Chapter 5). The decomposing method is used for the quantification of energy saving potential for the bottom-up model. For the power generation scenarios studies, the framework on integrated approach is used.

4. Top-down Approach – Case Studies

4.1. Introduction

LCA-LCCA was carried out for four power generation technologies under the top-down approach. For a centralised power generation option, a 250 MW oil-fired steam turbine plant, a 367.5 MW gas-fired combined cycle plant and a 250 MW Orimulsion-fired steam turbine plant were studied. Currently the former two technologies are predominantly used to meet the power demand (see Section 7.2.2) while the latter would be used in the future (see Section 4.6). For distributed power generation system (DG), a 2.7 kW_p solar PV system and a 5 kW proton exchange membrane fuel cell (PEMFC) were studied. The solar PV system was installed as a demonstration project¹⁰ in Singapore. The fuel cell system is likely to be installed for demonstration (see Section 7.2.3).

The life cycle primary energy use, GWP and the cost of electricity from these five power generation systems were estimated and are presented in this chapter in five sections. For the LCA-LCCA, the research methodology described in Chapter 3 is used. For the centralised power generation technologies, the functional unit was defined as one kWh of electricity delivered to the grid. Thus, establishment of transmission and distribution (T&D) network was not included. In the case of DG, the functional unit was one kWh electricity generated. It was assumed that the generated electricity from DG would be consumed locally and thus hardly any T&D losses will occur.

¹⁰ 8.8 kW_p solar PV systems consists 2.7 kW_p mono-crystalline, 3 kW_p poly-crystalline and 3.12 kW_p CIS thin film have been installed.

4.2. Oil-fired steam turbine plant

A hypothetical 250 MW oil-fired steam turbine plant was considered and its operating parameters are given in Table 4.1. Figure 4.1 shows the system boundary, which was drawn in such a way so as to account for all primary fossil energy use and their associated GHG emissions.

Table 4.1. Operating parameters of oil-fired steam turbine plant

Installed capacity	250 MW
Plant annual net efficiency	33 %
Plant annual load factor	70 %
Annual net electricity generation	1512 million kWh _e
Expected life time of power plant	25 Years
Total life cycle electricity generation	37,800 million kWh _e

Fig. 4.1. LCA boundary of oil-fired steam turbine plant

4.2.1. Data sources

Due to the difficulties in obtaining primary data from local power companies, secondary data were retrieved and normalised to reflect Singapore conditions. Material inventory in the construction phase was established based on specific material used (tonne/MW) in previous studies (Spath et al., 1999; GEMIS, 2002). Only bulk materials like steel, iron and concrete were accounted. Though other materials like copper, PVC, glass are used in the construction phase, hardly any database on the use of these materials was found. However, from a sensitivity analysis (see Section 4.2.4), it is found that energy use and emission due to use of these materials is not significant relative to the total energy use and emissions during the operational phase.

In the operational phase, total fuel oil requirement for production of electricity generated during the entire lifetime of the plant (25 years) was estimated from the net plant efficiency and the lower heating value of fuel oil (40.19 GJ/t). The start-up energy use was not included due to lack of data. The material inventory of the construction and operational phases are given in Table 4.2.

Energy use for extraction and exploration of materials were estimated from their specific energy consumption (GEMIS, 2002). The energy requirements for manufacturing and assembling of plant equipment were assumed to be 30 % of the energy used for material extraction (Wenzel, 2001). Direct energy use in construction of the power plant was assumed to be 10 % of the energy used for material production and manufacturing.

Energy used for the upstream process of fuel oil production was categorised as (i) energy consumed at oil field (extraction of crude, flaring and leakages) and (ii)

energy consumed in refinery to process the crude oil. Energy use in transportation of oil was estimated separately.

Table 4.2. Materials inventory of oil-fired steam turbine plant

Materials inflow	Quantity (tonnes)
<i>Construction Phase</i>	
Steel (GEMIS, 2002)	12,500
Iron (Spath et al., 1999)	155
Aluminium (Spath et al., 1999)	105
Concrete (GEMIS, 2002)	37,500
Water (DRPL, 1993)	75,000
<i>Operational phase</i>	
Fuel oil	10,260,354
Boiler feed water (DRPL, 1993)	2,646,000

Singapore imported over 70 % of its oil from the Middle East (Singapore Trade Development Board, 2001). Energy consumption in on-site machineries in oil field was estimated as 557 MJ/t of crude output (Yoon and Yamada, 2002). The gas flaring data for all those countries from which Singapore imported its oil was not found. Based on Yoon and Yamada (2002), the average flaring rate in the Middle East oil fields was about 6.3 %, which was about a half of the world’s average gas-flaring rate of 12.9 % (Eni Company, 2002). From the available data, a weighted average for gas flaring was estimated to be about 421 MJ/t of crude produced. It is far less than the world’s average flaring rate of 1250 to 1680 MJ/t of crude oil extracted (Haugland, 2002). The total energy consumed at the oil field (in both on-site equipments and flaring) were allocated to the crude oil and value added gases produced. Thus the net energy used at the oil field was estimated to be about 890 MJ/t-crude produced. This figure was used in this study. This is comparable with GEMIS (2002)’s value of about

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1190 MJ/t of crude, which also includes the energy consumed for construction of oil exploration and extraction machineries.

Energy consumption data for processing of crude oil, i.e. production of fuel oil, were retrieved from the literature (Lawrence et al., 1980; Bodewes and Lugten, 1992; Yoon and Yamada, 2002; GEMIS, 2002; EIA, 2002). Generally, the data varied between 1.6 and 3.8 GJ/t of processed crude. To avoid over-estimation, and considering that fuel oil processes do not require much energy, and that the Singapore refineries are considered to be energy efficient, the lower average value of the thermal energy was used as energy consumed in refinery. The electrical energy consumption of 35 MJ/t (Yoon and Yamada, 2002) was converted to thermal energy equivalent and specific energy consumption of 1.896 GJ/t of fuel oil produced. This figure was taken as energy used in refineries.

In the decommissioning phase, there would hardly be any material inflow. Instead, some metals would be recovered through recycling. For the material recycling and disposal scenario, it was assumed that about 70 % of steel, iron and aluminium would be recycled with a recovery rate of 90 %, while the concrete debris would be land filled. Specific energy consumption for recycling of metal was taken from Wenzel (2001). The energy equivalent of recovered metal, i.e., energy consumed in extraction of the metals (GEMIS, 2002) was considered as energy gain in the decommissioning phase. The energy gain was higher than the energy consumed for recycling of metals and thus it is shown with a negative sign (see Table 4.3).

The transportation energy was estimated using the specific transportation energy of GEMIS (2002). The plant equipment was imported from Europe while crude oil is from the Middle East and they were transported by ships. The fuel oil was transported

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from the refinery to power plant by pipelines. The other materials were produced locally and transported by trucks.

The primary source of CO₂ and N₂O was the combustion of fuel oil while CH₄ was from leakages/venting in oil field and refinery. Specific emission factors of 76.6 and 55.8 t-CO₂/TJ_t were used for oil and natural gas, respectively (IPCC, 1996c). In case of unknown source of primary energy (see Section 3.2.3), 76 t-CO₂/TJ_t was used.

CH₄ emission occurs via venting and chronic leaks in oil extraction, handling and storage of crude and refining (IPCC, 1996b; 2000). The fugitive CH₄ emission in extraction of oil was in the range of 40,505-43,398 kg/PJ_t of crude produced. CH₄ emission through venting was in the range of 1793-78,117 kg/PJ_t of crude produced while flaring emission was 144-7811 kg/PJ_t of crude produced (IPCC, 2000). Generally, CH₄ emission in OPEC and other selected oil producing countries are higher (IPCC, 1996b). Singapore imports a major share of its oil from these countries. However, the actual emission factor was not available. Thus, an average CH₄ emission factor of 85,884 kg/PJ_t of crude produced was used in this study. CH₄ emission also occurred in handling (loading and off-loading) of oil in transportation. It was found to be 745 kg/PJ of oil tanked (IPCC, 1996b). The fugitive emission in refinery was of the order of 90 to 1400 kg/PJ of oil refined (IPCC, 1996b). Since Singapore has well-equipped and maintained refineries, the lower value of CH₄ emission, 90 kg/PJ_t of oil refined, was used in this study. Though un-reacted fuel components (CH₄ and non-methane volatile organic compounds) can be released to the atmosphere during combustion, the quantity is very low in large-sized steam generating plants (European Environment Agency, 1996). Thus, combustion related CH₄ emission was ignored.

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The CH₄ emission associated with secondary energy use was also ignored due to uncertainties in the primary source of energy and its relatively insignificant magnitude.

N₂O emissions can potentially occur in flaring at oil fields and combustion of fuel oil at power plants. The European Environment Agency (1996) reported that the formation mechanism of N₂O has not yet been completely clarified. N₂O emission from flaring was found to be 18 kg/PJ_t of crude oil produced (IPCC, 2000). N₂O emission from combustion plant varied between 1.4-14.8 kg/TJ_t of oil burned depending on plant size (European Environment Agency, 1996). For the plant size considered in this study, an emission factor of 1.4 kg/TJ_t was used.

4.2.2. Life cycle energy use

From the life cycle energy use, energy use per functional unit is estimated to be about 11.86 MJ/kWh_e and the breakdown for the energy use in each of the life cycle phases is presented in Table 4.3. It can be seen that the upstream process of the fuel oil production alone accounts for about 6.5 % of the life cycle energy use. Transportation accounted for about 1.5 % of the life cycle energy use, arising mainly from the transportation of crude oil by bunkers. Energy use in construction phase is very low (0.13 %). It was observed from a sensitivity analysis (see section 4.2.4) that even if the energy use for plant material was doubled, its effect on life cycle energy use per functional unit would not be significant. Although energy is consumed in recycling of metals, the net energy gain from the recovered material is more than the energy required for extraction of the virgin metal.

From Table 4.3, it can be seen that the secondary operations/processes associated with the construction of power plant and upstream processes of fuel oil production and transportation consumed about 8.8 % of the fuel embedded energy.

This energy is generally ignored in the conventional evaluation practices. Hence, they are termed as “*hidden energy*”.

Table 4.3. Life cycle energy use in the steam turbine plant

Life cycle phases	Energy use	
	<i>MJ/kWh_e</i>	%
Construction phase	0.015	0.13
Operational phase (Upstream processes of fuel oil)	11.676 (0.767)	98.32 (6.46)
Decommissioning phase	-0.001	-0.01
Transportations	0.185	1.56
Specific life cycle energy use	11.875	100
Specific fuel energy (embedded energy)	10.909	
Hidden primary energy use	0.966	8.13

4.2.3. Life cycle GWP

Life cycle GHG emission per functional unit is shown in Table 4.4. The GWP of electricity generation from the oil-fired steam turbine plant is estimated to be 932 g-CO₂ equivalent/ kWh_e. Figure 4.2 shows the distribution of GWP in life cycle phases. The operational phase contributed for 90 % of the GWP and the upstream processes of fuel oil production alone accounted for 8 %. From Table 4.4, it can be seen that CO₂ contributed 96.6 % of the total GWP while CH₄ and N₂O accounted for 2.9 % and 0.5 %, respectively. In conventional emission inventories on electricity generation, CH₄ and N₂O emissions are ignored. The hidden GHG emission from the upstream process of oil extraction and other material use is about 12 % in addition to the CO₂ emission from the combustion of oil in the operational phase.

Table 4.4. GHG emission and GWP from oil-fired steam turbine plant

Greenhouse gases	GHG (g/kWh _e)	GWP (g-CO ₂ equivalent/ kWh _e)	Share of GWP (%)
CO ₂ emission	905	905	96.6
CH ₄ emission	1.07	22	2.9
N ₂ O emission	0.02	5	0.5
Total global warming potential (GWP)		932	100
CO ₂ emission from combustion of fuel oil in operational phase alone		836	89.64
Hidden emissions		97	11.56

4.2.4. Sensitivity analysis

For the sensitivity analysis, life cycle energy use of 11.86 kJ/kWh_e and GWP of 932 g-CO₂ equivalent/kWh_e corresponding to plant efficiency of 33 %, load factor of 70 % and lifetime of 25 years was taken as the base (reference) case.

Fig. 4.2. Distribution of GWP in oil-fired steam turbine plant

A one percent increase in plant efficiency would save about 349 kJ/kWh_e and 27 g-CO₂/kWh_e. On the other hand, a one percent decrease in efficiency would cause an excess energy use of 371 kJ/kWh_e and 29 g-CO₂/kWh_e. Though these magnitudes of

changes per functional unit appear to be very small, their collective effects would be significant considering the total amount of electricity generation.

Extending the lifetime from 25 years to 30 years reduces the energy use by 2.6 kJ/kWh_e and GHG emission by 0.3 g/kWh_e. On the other hand, reducing the lifetime to 20 years increases the energy use by 3.9 kJ/kWh_e and GHG emission by 0.4 g/kWh_e. Similarly, a 10 % increase in annual load factor decreases the energy use by 2 kJ/kWh_e while decreasing emission by 0.2 g/kWh_e.

In the base case, only the bulk materials were taken into account due to lack of data. If the material use in plant equipment was 30 % more than what was considered in the base case, then the energy use and GHG would have increased by 4.7 kJ/kWh_e and 0.5 g-CO₂/kWh_e. If the material would not to be recycled, unlike in the base case, then 1.6 kJ/kWh_e excess energy would be consumed relative to the base case.

4.2.5. Efficiency versus life cycle energy and GWP

From sensitivity analysis, it can be seen that efficiency is the predominant factor that determines life cycle energy use and GWP. Hence, life cycle energy use was estimated in a range of plant efficiency for a fixed lifetime of 25 years and load factor of 70 %. Then a curve was fitted between the efficiency (η) (X axis) and life cycle energy use (Y axis) as shown in Figure 4.3. From the curve, a power correlation is established and given in Equation (4.1). Comparing this correlation with the conventional (theoretical) relation between energy efficiency and fuel embedded energy use ($= 3.6 \eta^{-1}$ MJ/kWh_e), the difference in the coefficient can be attributed to the hidden energy use. There is hardly any variation in the power exponent. This is because other factors like plant lifetime or plant annual load factors do not significantly affect the life cycle energy use per functional unit. Hence, these correlations can be

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used for estimation of life cycle energy use for a given plant efficiency. Likewise, GWP with respect to plant efficiency was also plotted (see Fig. 4.3) and derived correlation equation is shown in Equation (4.2).

$$[\text{Life cycle energy use}]_{\text{Steam turbine}} = 3.9169 \eta^{-0.9989} \text{ MJ}_e/\text{kWh}_e, \quad (4.1)$$

$$[\text{Life cycle GHG emission}]_{\text{Steam turbine}} = 309.15 \eta^{-0.9984} \text{ g-CO}_2 \text{ equivalent}/\text{kWh}_e \quad (4.2)$$

where η is the efficiency of the plant.

Fig. 4.3. Efficiency versus energy use and GWP from steam turbine plant

4.2.6. LCCA of oil-fired steam turbine plant

For the LCCA, the boundary was maintained as in the LCA. Hence, costs involved in transmission and distribution (T&D) network were not included. The cost data used in the LCCA was obtained from Teo (2002; 2002a). Equipment cost and cost involved in the construction and commissioning of the plant equipment were considered as capital cost. However, land cost was not included. For the capital cost,

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an annual interest rate of 5 % was used in LCCA. The O & M cost was assumed to be 4 % of the capital cost. It includes the scheduled maintenance cost, replacement cost and labour costs. An annual escalation rate of 2 % on O & M cost and 2 % discount rate were considered in LCCA. For the energy cost, fuel oil price of S\$ 285 per tonne was used with an annual escalation of 2 %. The decommissioning and disposal costs were assumed to be 3 % of the capital while the salvage value of 5 % of the capital was accounted in the LCCA.

The LCCA was carried out for base and peak load operations. In the base load case, the plant operates continuously (shutdown only for annual maintenance) whereas during the peak load, the plant operates about 3 to 4 hours daily, i.e. annual load factor of 12 % as compared to 70 % in the base load. The cost of electricity generation is about 10.49 ¢/kWh_e at the base load regime, but almost doubled to 19 ¢/kWh_e at peak load operation regime. Figures 4.4 and 4.5 show the cost distribution at base and peak load operation regime, respectively. There is a significant variation in cost distributions. Due to lower number of annual operating hours, the capital cost and O & M cost are high for peak load operation. The cost of generation at peak load operation is about 80 % higher than in the base load operation. Steam turbine is not normally used for peak load demand due to its high start-up time and energy use.

The cost of electricity generation primarily depends on the fuel-oil price while the oil consumption varies with operating efficiency of the power plant. Therefore, the cost of electricity generation is estimated for a range of fuel oil price and net plant efficiency and is shown in Figure 4.6.

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Fig. 4.4. LCC distribution in steam turbine at base load operation

Fig. 4.5. LCC distribution in steam turbine at peak load operation

Fig. 4.6. LCC of electricity generation from oil-fired plant

4.3. Gas-fired combined cycle plant

The 367.5 MW gas-fired combined cycle plant commenced its operation in 2001 and its key operating parameters are given in Table 4.5. Figure 4.7 shows the LCA boundary.

Table 4.5. Operating parameters of gas-fired combined cycle plant

Installed capacity	367.5 MW
Plant net efficiency	50 %
Plant annual load factor	83 %
Annual operational hours	8000
Annual net electricity generation	2,450 Million kWh _e
Annual natural gas consumption	450 million m ³
Designed life time of power plant	25 Years

Fig. 4.7. LCA boundary of gas-fired combined cycle plant

4.3.1. Data sources

Primary data were obtained from a local power company (Tuas Power, 2004) and secondary data were retrieved from literature. The combined cycle plant is a single shaft configuration of a generator, a gas turbine and a steam turbine. The gas turbine operates at 1400°C with power output of 239.1 MW. Steam is generated from a heat recovery steam generator at 110 bar [high-pressure (HP) steam at 540°C], 35.9 bar [intermediate-pressure (IP) steam at 568°C] and 7 bar [low-pressure (LP) steam at 251.9°C]. Exhaust gas is dumped to the atmosphere at 105°C. A single cylinder, triple pressure steam turbine with power output of 128.4 MW runs with input of 106 bar, 538°C HP steam, 35 bar, 566°C IP steam and 6 bar 250°C LP steam.

The material inventory for the construction phase was established based on the data from Spath and Mann (2000) and GEMIS (2002). In the operational phase, the plant operated 8,000 hours annually with a load factor ranging from 70 to 90 %. Annual gross electricity generation was 2.5 TWh_e and about 2 % of the generated electricity was used as auxiliary power consumptions. Therefore the net electricity delivered to the grid was estimated to be 2.45 TWh_e. Annual average load factor was estimated to be 83 %. The plant's annual natural gas consumption was 450 million m³ (17.5 million MMBTU) based on a higher heating value of 41 MJ/m³ (1100 MBTU/SCF). This includes all start-up energy use, which is estimated to be about 13.5 MWh_e and 34,737 m³ of natural gas per start-ups. For this study, a lower heating value of 39.19 MJ/m³ is used for natural gas. Based on the lower heating value, the calculated gross- and net efficiencies of the plant are 51 % and 50 %, respectively. Based on the annual natural gas consumption, total natural gas use during the entire operational lifetime of the plant, taken to be 25 years, was estimated. The materials inventory for the construction and operational phases are given in Table 4.6.

Table 4.6. Materials inventory of gas-fired combined cycle plant

Materials inflow	Quantity
Construction Phase (in tonne)	
Steel (Spath and Mann, 2000)	11,404
Iron (Spath and Mann, 2000)	150
Aluminium (Spath and Mann, 2000)	75
Concrete (Spath and Mann, 2000)	35,923
Water (DRPL 1993)	110,250
Operational phase (in million m ³)	
Natural gas	11,267
Boiler feed-water (DRPL, 1993)	1.155

Natural gas is imported from Indonesia via a 0.71 m (28-inch) diameter submarine pipeline over a distance of about 540 km (Lim et al., 2003). The site-specific energy data for natural gas production and processing in Indonesia was not found. Hence, data from India was used (Jungbluth, 1995; GEMIS, 2002). Energy use for the production and processing of natural gas includes energy use for on-site machineries, souring/sweetening processes, gas flaring and leakages/venting. Energy consumption for on-site machineries in gas field was estimated to be 0.04524 TJ/TJ gas produced while flaring was 0.03150 TJ/TJ (Jungbluth, 1995). Gas leakages in gas production vary in the range of 0.06 to 0.15 % (GEMIS, 2002). An average value of 0.105 % was considered in this study. Energy use for transportation of natural gas through pipeline from Indonesia to Singapore was also estimated based on GEMIS (2002).

In the decommissioning phase, the same recycling scenarios of the oil-fired steam turbine plant were used (see Section 4.2.1).

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For the transportation energy, the power plant equipment was transported from Japan by ship while natural gas was conveyed from Indonesia by submarine pipelines. The specific transportation energy for submarine pipeline was not found. Thus energy use from landline pipeline transportation was used, and taken to be 0.289 MJ/t-km (GEMIS, 2002). It is very likely that energy use for submarine and landline pipelines transportation would be the same, even though energy uses for construction of pipelines differ widely. Gas leakage in pipeline transportation of 0.006 % per 100 km (GEMIS, 2002) is used in this study, which is accounted in the energy losses, as well as in CH₄ emission inventories.

The fugitive emissions from natural gas related activities include all emissions from gas production, processing, transport, and use of natural gas, and from non-productive combustion (e.g. flaring and waste gas incineration). Fugitive emissions are difficult to quantify accurately due to limited availability of emission-source data. In this study, IPCC (2000) data for the North American region was used. Though actual emission factor for gas production activities in Indonesia could be slightly higher due to older technologies being used, no correction factors were used due to uncertainties.

CH₄ emission occurs from fugitive, flaring, and venting in natural gas production (98.4 kg/TJ), processing (1.5 kg/TJ) and transmission (95.3 kg/TJ) were estimated based on data from IPCC (2000). The combustion related CH₄ emission was ignored because it is very low in large-sized plants (European Environment Agency, 1996). The CH₄ emission associated with secondary energy use was also ignored due to uncertainties in the primary source of energy and its relative insignificance.

N₂O emission from flaring was found to be 2.9 kg/PJ_i of natural gas produced (IPCC, 2000). N₂O emission from combustion plants varied between 0.1 and 3 kg/TJ_i

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of gas burned. N₂O emission was found to be higher at lower temperatures, particularly below 1000°C (European Environment Agency, 1996). Since the studied plant’s operating temperature is over 1400°C, the lower value of N₂O emission was used in this study. However, from the sensitivity analysis, the variation due to this uncertainty is estimated to be about 1.6 % of life cycle GWP.

4.3.2. Life cycle energy use

Energy use per functional unit is estimated to be about 7.79 MJ/kWh_e and the energy use pattern is presented in Table 4.7. It can be seen that *hidden energy use* accounted for about 8.2 % of the fuel embedded energy. The natural gas production and processing accounted for about 7.18 % of the life cycle energy use. Energy use in construction phase is very low (0.11 %). Even if the energy use for plant material were doubled, its effect on life cycle energy use per functional unit is significant (see Figures 4.9 and 4.10).

Table 4.7. Life cycle energy use in the gas-fired combined cycle plant

Life cycle phases	Energy use	
	MJ/kWh _e	%
Construction phase	0.009	0.11
Operational phase (For natural gas production and processing)	7.760 (0.56)	99.60 (7.18)
Decommissioning phase	-0.001	-0.01
Transportations	0.023	0.30
Specific life cycle energy use	7.791	100
Specific fuel energy (embedded energy)	7.200	
Hidden primary energy use	0.591	8.22

4.3.3. Life cycle GWP

Table 4.8 shows the estimated life cycle GHG emissions per functional unit. The GWP of electricity generation from the combined cycle plant is estimated to be 474 g-CO₂ equivalent/kWh_e. Figure 4.8 shows the distribution of GWP among the different phases. The direct combustion of gas in the operational phase contributed 85 % of the GWP and the gas production process accounted for 12 %. Transportation accounted for 3 % of the GWP, mainly due to venting of natural gas to the atmosphere.

From Table 4.8, it can be seen that the *hidden* GHG emissions from the production, processing and transportation of natural gas and associated material use contribute about 18 % additional CO₂ emission on top of the emission due to direct combustion of gas in the operational phase. This is comparable with the results of the LCA study of Spath and Mann (2000), in which hidden GWP (from gas production and transportation) accounted for about 25 % of the total life cycle GWP. The higher value obtained by Spath and Mann could be attributed to the consideration of construction of gas pipeline to the power plant (an allocations of 19.3 % was used). In addition, the length of the natural gas pipeline in the Spath and Mann study is 4000 km as compared to 540 km in this study.

Fig. 4.8. Distribution of GWP in combined cycle plant

Table 4.8. Specific GHG emission and GWP from combined cycle plant

Greenhouse gases	GHG (g/kWh _e)	GWP (g-CO ₂ equivalent/ kWh _e)	Share of GWP (%)
CO ₂ emission	436.65	437	92.2
CH ₄ emission	1.44	30	6.4
N ₂ O emission	0.02	7	1.4
Total global warming potential (GWP)		474	100
CO ₂ emission from combustion of natural gas in operational phase alone		402	
<i>Hidden emissions</i>		72	17.9

4.3.4. Sensitivity analysis

For the sensitivity analysis, the base case was fixed at 7.79 MJ/kWh_e and 474 g-CO₂/kWh_e, which corresponds to a plant efficiency of 50 %, load factor of 80 % and lifetime of 25 years. The results of the sensitivity analysis are presented in Figures 4.9 and 4.10.

It can be seen that, one percent increase in plant efficiency from the base case would save about 152 kJ/kWh_e and reduce emissions by 9.3 g-CO₂/kWh_e while a one percentage decrease in efficiency would cause an additional energy use of 158 kJ/kWh_e and increase emissions by 9.6 g-CO₂/kWh_e. Though these magnitudes of changes per functional unit appear to be very small, their collective effects would be significant considering the total amount of electricity generation from this plant. For example, a one percent increase of plant efficiency would save annually about 9.5 million m³ of natural gas and emissions reduced by about 22,785 tonnes of CO₂ equivalents.

Like in the oil-fired steam turbine plant, correlations are established between plant net efficiency and life cycle energy and GWP and are presented in Figure 4.11 and Equations (4.3) and (4.4).

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Fig. 4.9. Sensitivity analysis: Life cycle energy use

Fig. 4.10. Sensitivity analysis: Life cycle GWP

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Fig. 4.11. Efficiency versus energy use and GWP from combined cycle plant

$$[\text{Life cycle energy use}]_{\text{Combined cycle}} = 3.8991 \eta^{-0.9988} \text{ MJ}_t/\text{kWh}_e, \quad (4.3)$$

$$[\text{Life cycle GHG emission}]_{\text{Combined cycle}} = 237.2 \eta^{-0.9979} \text{ g-CO}_2 \text{ equivalent}/\text{kWh}_e, \quad (4.4)$$

Extending the lifetime from 25 years to 30 years reduces the specific energy use by 1.4 kJ/kWh_e and GHG emission by 0.15 g/kWh_e while reducing the lifetime to 20 years increases the specific energy use by 2.1 kJ/kWh_e and GHG emission by 0.23 g-CO₂/kWh_e. Similarly, a 10 % decrease in annual load factor results in an increase in energy use by 1.19 kJ/kWh_e while emission is increased by 0.12 g-CO₂/kWh_e. These changes are quite insignificant. At the same time it should be noted that the change in load factor could affect the plant operating efficiency.

In production and processing of natural gas, the flaring of gas accounted for a considerable amount of energy loss as well as GWP. A 25 %, 50 % and 75 % reduction in gas flaring would result in a reduction in energy use of 56, 113, 170 kJ/kWh_e and

GWP of 3.7, 7.5, 11.2 g-CO₂/kWh_e, respectively. In the context of this study, a 50 % reduction in flaring could save about 7.2 million m³ gas and 18,375 t-CO₂ equivalents.

4.3.5. LCCA of gas-fired combined cycle plant

The capital cost data used in the LCCA was obtained from a power company (Tuas Power, 2004). The O & M cost was assumed to be 3 % of the capital cost. It includes the scheduled maintenance-, spares- and manpower costs. For the fuel cost, a natural gas price of S\$ 8.38 per MMBTU (based on the lower heating value) was used. The decommissioning and disposal cost was assumed to be 3 % of the capital cost while the salvage value of 5 % of the capital was assumed. The interest-, discount- and escalation rates are the same as in the LCCA of the oil-fired plant (see Section 4.2.6).

The cost of electricity generation is calculated to be 7.76 ¢/kWh_e and the life cycle cost distribution is shown in Figure 4.12. It can be seen that the fuel cost is dominant (82 %) followed by the capital cost (12 %). Thus, cost of electricity generation primarily depends on the gas price while the gas consumption varies with plant operating efficiency. Therefore, the cost of electricity generation is estimated for varying natural gas prices at various plant operating efficiencies and presented in Figure 4.13.

Fig. 4.12. LCC distribution in combined cycle plant

Fig. 4.13. Cost of electricity from combined cycle plant

4.4. Solar PV system

Many LCA studies were carried out for solar PV systems (Hagedorn, 1989; Phylipsen and Alsema, 1995; Nieuwlaar et al., 1996; Kato et al., 1997; GEMIS, 2002; Karl and Theresa, 2002; Gagnon et al., 2002). Since the amount of electricity generated from such systems is dependent on local solar irradiation and weather condition that influences the efficiency of solar PV module, it is more appropriate to use local studies for long-term decision-making. Thus, this LCA was carried out for a grid integrated 2.7 kW_p mono-crystalline solar PV system, which has been operating in Singapore since May 2002 as a demonstration project.

Figure 4.14 shows the boundary of this LCA study, in which manufacturing of solar PV modules, supporting structures, inverters and their accessories are included. The functional unit is defined as one kWh of AC electricity (kWh_e) generated from the solar PV system.

4.4.1. Description of the solar PV system

The 2.7 kW_p solar PV system consists of 36 mono-crystalline modules (12 V, 75 W_p) mounted on a building rooftop with aluminium supporting structures and

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concrete blocks for the base. The 12 modules are connected in series to generate 144 V DC (900 W_p) power. Three strings, each having 12 modules, are connected to three inverters of 1.5 kVA rated capacity. The AC output from the inverters is connected to the three phases of the grid. Control units are installed in such a way so as to use the electricity for the local load first, i.e. within the building. Since electricity generated from the solar PV system is a small fraction of the building requirement, all the generated electricity is used locally, and none exported to the grid.

Fig. 4.14. LCA boundary of solar PV system

A data logger is installed to record electrical (power, voltage, current, power factor, etc.) and meteorological data (radiation, temperatures, wind speed, rain fall, humidity, etc.). Three phases of the inverters DC inputs and AC outputs are measured, and six sensors are installed to measure the temperature of the mono-crystalline solar PV modules.

4.4.2. Data sources

The primary data for the construction phase was taken from the project documents and suppliers' catalogue (BCA, 2004). In the operational and decommissioning phases, hardly any material inflow is involved. Figure 4.15 shows the material inventory of the solar PV system.

Fig. 4.15. Materials inventory of solar PV system

Energy consumption for manufacturing of mono-crystalline modules varied between 11 and 45 MWh_t/kW_p (refer to Table 4.9). For this study, 16 MWh_t/kW_p was adapted from Karl and Theresa (2002) as it was specific to the solar PV module¹¹ installed in this study. For aluminium and concrete supporting structures, the specific energy consumption was taken from GEMIS (2002). The specific energy consumption for the inverters was 0.17 MWh_e/kW_p (Kato et al., 1997). Though it was electrical energy, it was assumed to be thermal energy because energy consumption figures of Kato et al. (1997) were on par with the thermal energy equivalent of other studies (see Table 4.9).

¹¹ The manufacturing process included are growth of the silicon crystalline ingot, slicing the ingot into wafers and processing into solar cells and interconnecting the cells into circuits/laminating to glass and completing the assembly of a complete framed and packaged module (Karl and Theresa, 2002).

Table 4.9. Energy use in manufacturing of mono-crystalline PV module

Source	Primary energy use	Processes included in the study
Hagedorn, 1989	11 - 17.5 MWh _t /kW _p [#]	Exploitation and preparation of raw materials, process energy, hidden energy of input materials and production equipment
Kato et al., 1997	17.70 MWh _e /kW _p ^{##}	From quartz (production of MG silicon) to module fabrication
	12.4 MWh _e /kW _p	Off-grade silicon (from semiconductor industry) to module fabrication
Mathur et al., 2002	40.55 MWh _t /kW _p	Manufacturing of silicon wafers to modules fabrication
Karl and Theresa, 2002 ⁺	16 MWh _t /kW _p	From growth of the silicon crystalline ingot to module fabrication
GEMIS, 2002	13.78 MWh _t /kW _p ⁺⁺	From mineral sand to module fabrication

[#] In different technology level in different time frame.

^{##} Based on this study, the energy pay back time was 15.5 years for 1427 kWh/m²/y solar radiation.

⁺ For Siemens SP 75 modules used in this study.

⁺⁺ Estimated from the energy requirement for production of mono-crystalline module (131.23 MWh/tonne) and the module requirement (105 tonnes/MW_p).

In the decommissioning phase, it was assumed that PV module would be land filled after removing the aluminium frames. 10 % of the module weight was considered as the aluminium frames (Phylipsen and Alsema, 1995). It was assumed that 90 % of the aluminium would be recycled with 90 % recovery rate.

For transportation energy, the solar PV modules were imported from the USA while the inverters were from Germany. It was assumed that they were transported by ship. The other materials were obtained locally and transported by trucks.

In the operational phase, there is no external source of energy supply. Though control systems are installed, they draw energy from the solar PV module itself. Annually the PV system generated 2624 kWh_e in 2002-03 and 2581 kWh_e in fiscal year

2003-04. For the calculations of life cycle energy use and GWP, an annual electricity generation of 2600 kWh_e was used.

4.4.3. Life cycle energy use and GWP

Energy use per functional unit is estimated as 2.94 MJ/kWh_e. Figure 4.16 shows the distribution of life cycle energy use in the solar PV system. The manufacturing of PV module accounted for about 81 % of the life cycle energy use. After crediting for aluminium recovered from recycling process, the supporting structures accounted for about 10 % of the life cycle energy use while the recycling processes accounted for 7.5 %.

Fig. 4.16. Distribution of energy use in solar PV system

Though there is no direct emission of GHG, indirect emissions potentially occur from the energy consumed for the manufacturing of solar PV module and its accessories. However, the primary energy sources were unknown. Thus CO₂ was estimated using the average emission factors (IPCC, 1996c) of coal, oil and gas as in van Margreet et al. (1994). CH₄ and N₂O emissions were not accounted for due to uncertainties in primary source of energy and its relatively insignificant magnitude. The GWP of electricity generation from the solar PV system is about 219 g-CO₂/kWh_e.

4.4.4. Improvement assessment

Potential areas to reduce the primary energy use could be: (i) technology improvement in the manufacturing of PV module, (ii) using alternate supporting structures and (iii) improving efficiency of solar PV modules.

The manufacturing of solar PV module accounted for 81 % of the life cycle energy use. Improvement in PV module production technology or a mass production would lead to a reduction in energy usage. The manufacturers say that energy usage could be reduced by 50 % if the production is doubled. If the primary energy use in the manufacturing of PV module is reduced by 50 %, then the specific primary energy use would be reduced to 1.74 MJ/kWh_e and the GWP would be 130 g-CO₂/kWh_e.

Instead of the aluminium structure, a concrete structure could be used and energy use can be reduced. If the aluminium usage for supporting structure is reduced to 10 % of the current aluminium use, then the life cycle primary energy use would be decreased to 2.41 MJ/kWh_e while the GWP would be about 179 g-CO₂/kWh_e. Alternatively, solar PV modules can be integrated into the building thereby energy and cost on supporting structure can be minimised.

Under the standard laboratory test conditions (1000 W/m² and 25°C), the efficiency of the solar PV module used in this system was 11.9 %. However, the actual efficiency¹² was only about 7.9 %. This could be due to the high ambient and module temperatures. During peak radiation hours, the module temperature reached over 60°C at their bottom surface. If the net system efficiency would be increased to 10.6 %, after considering the inverter losses of 10 %, by natural cooling of modules or

¹² Average monthly net conversion efficiency of the solar PV system (solar radiation to AC power) varied between 6.9 % and 8.9 %. The inverters accounted for a 10 % electricity loss.

other means, the energy use can then be reduced to 2.2 MJ/kWh_e and the GWP to 165 g-CO₂/kWh_e.

From the above three scenarios, it can be seen that there is a potential to reduce the primary energy use. If all the above three scenarios could be achieved together, primary energy use could be reduced to as low as 0.9 MJ/kWh_e and the GWP to 68 g-CO₂/kWh_e.

It is also observed that despite the higher efficiency in mono-crystalline module, electricity generation from mono-crystalline module is low as compared to polycrystalline and CIS thin film systems. Electricity generation per installed capacity (kWh_e/kW_p) in mono-crystalline module is low because of its low module area per installed capacity (m²/kW_p).

4.4.5. LCCA of solar PV

The total capital cost of the 2.7 kW_p solar PV system was about S\$ 36,500, which includes the cost of the PV modules, supporting structures, inverters, accessories, erection and commissioning. The cost of PV modules accounted for 63 % of the capital cost and the specific PV module cost worked out to be S\$ 8.5 per W_p. An annual O & M cost of about S\$ 600 was considered in the LCCA to cover up the cost involved in the fortnightly cleaning of the PV modules. Cost involved in the dismantling of the solar PV system was estimated to be S\$ 1200. It was assumed that the PV modules would not have any salvage value. Instead, there may be costs in disposing the PV module and it was not considered due to inadequate information. However, a salvage value of S\$ 735¹³ was included for the aluminium supporting structures and aluminium

¹³ Based on market value of recyclable aluminium @ S\$ 1400 per tonne.

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frames in the solar PV modules. The interest-, discount- and escalation rates were the same as in the earlier LCCA case studies (see Section 4.2.6).

From the LCCA, cost of electricity generation from the solar PV system is calculated as 123 ¢/kWh_e. Figure 4.17 shows the LCC distribution of electricity generated from the solar PV system. The capital cost accounted for 81 % of the LCC, of which the PV module is 51 % and balance of the system (supporting structures, inverters, accessories, erection and commissioning cost, etc.) is 30 %. Due to this high capital cost, interest on capital plays a significant role in the cost of electricity generated. Hence, a scenario was studied with a range of interest rates. In addition, the cost of electricity generation for various solar PV module price were studied. The results are presented in Figure 4.18.

Fig. 4.17. LCC distribution in solar PV system

Fig. 4.18. Cost of electricity generation from solar PV system

4.5. Fuel cells

Fuel cell is considered as a clean energy technology due to its environmental friendly emissions (water and heat). However, production of hydrogen may have negative impacts on the environment, depending upon the source of its production. Hence, net environmental impacts from fuel cell technology depend significantly on the source of hydrogen and the fuel cell technology. There are several types of fuel cells with different characteristics and uses (Vielstich et al., 2003). For this study, the PEMFC was chosen because they are being demonstrated for stationary power application and their technical performance are encouraging. Its relatively low operating temperature ($< 100^{\circ}\text{C}$) holds the promise of simplified technology. Easy dissipation of heat and no moving parts inside the converter make it easy to be placed within buildings. However, PEMFC operating on natural gas has one of the lowest electrical efficiency of all fuel cell systems because the temperature of the waste heat from the fuel cell is too low to be used in the fuel reforming process (Braun et al., 1999). Its efficiency is in the range of about 22-38 % depending on their rated power (EPRI, 2002; DoD, 2002; Rastler, 2003).

In Singapore, a test-bedding project is currently underway in a multi-storey car park where the lights are powered by fuel cells. A hypothetical 5 kW natural gas based PEMFC with external reformer was used for this LCA study. It was assumed to be operated with an efficiency of 26 % and a load factor of 70 % over its lifetime of 20 years (Fuel Cells, 2000). Figure 4.19 shows the LCA boundary. In the construction phase, production of fuel cell and balance of the plant were considered while the upstream process of natural gas production is included in the operational phase.

Fig. 4.19. LCA boundary of PEMFC

4.5.1. Data sources

Energy consumption data for the production of PEMFC was adapted from Pehnt (2001; 2003) and Sørensen (2004). For the production of PEMFC for stationary power applications, primary energy requirement was 5.1 GJ/kW_{el} (Pehnt, 2001). For the balance of materials, the data from the Solar PV plant was adapted. Energy and emission data for the upstream process of natural gas production and processing were used from the LCA of the gas-fired combined cycle plant (see Section 4.3.1). It was assumed that the fuel cells was imported from USA and transported by ships.

4.5.2. Life cycle energy use and GWP

The life cycle energy use is estimated to be 14.93 MJ/kWh_e and hidden energy use is about 7.8 %. The construction phase accounted for 0.32 % and the operational phase is 99.4 %, which are not very different from those of the gas-fired combined cycle plant (see Table 4.7).

As far as the emissions are concerned, CO₂ is the only source of direct emission in the operational phase and hardly any N₂O emission was released. Sources of CH₄

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emission were the usual natural gas upstream processes, which are discussed in Section 4.3.1. For the electricity generation from the fuel cell, the GWP is estimated as 832 g-CO₂-equivalents/kWh_e. The hidden emissions are about 16.37 %. It is slightly lower than the GWP from a gas-fired combined cycle plant with same operating efficiency. It is because there is hardly any N₂O emission from the fuel cell.

4.5.3. LCCA of PEM fuel cell

The capital cost of the PEMFC was assumed as S\$ 8500 per kW (California Energy Commission, 2004). The cost of the balance of the plant was used from the solar PV systems. The natural gas price was taken as S\$ 8.38 per MMBTU while the O & M cost was assumed to be 1 % of the capital cost. The interest-, discount- and escalation rates were used as in the earlier LCCAs. The cost of electricity generation is calculated to be 30.3 ¢/kWh_e. Figure 4.20 shows the cost distribution and it can be seen that the capital cost accounted for 59 % while the fuel cost is 33 %.

Fig. 4.20. Distribution of LCC in PEMFC

4.5.4. Future perspectives of fuel cell

From the efficiency point of view, it could have been concluded that fuel cell is not a good choice of power generation as the efficiency of a gas-fired combined cycle plant is more than 50 %. The motivation to include the option of fuel cell in the model

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was to use the insights for scenario development for the future. It should be borne in mind that fuel cell technologies are still at the infant stage of development, compared to conventional power plant technologies. Fuel cell technologies are benefiting from intense R&D and therefore higher efficiencies are expected in the near future. For PEMFC, efficiency is projected to be 40 % by 2005. If that would be the case, then the life cycle energy use and GWP would be 9.72 MJ_t/kWh_e and 586 g-CO₂-equivalents/kWh_e, respectively. This is better than the oil-fired steam turbine plant, as there would not be any significant improvement in efficiency of steam turbine in the near future. However, in terms of efficiency, it still could not compete with the combined cycle plant as a further improvement in efficiency also expected in the combined cycle plant. Nonetheless, for the peak load application the fuel cell would be energy efficient and environmentally friendly option, as gas turbines are currently used with an efficiency of less than 40 % for such applications. Also the T&D loss is nil in case of the distributed fuel cell. If the heat can be used for other application, especially for cooling, then fuel cell would be a prospective technology for Singapore. Sooner or later, fuel cells would become a promising technology for (for peak load or premium quality) power applications. When the technology is demonstrated, hydrogen can be produced even from landfill gases and gasification of wastes.

As far as the costs are concerned, ongoing technological innovations and advances will allow PEMFC to enter the market at very low cost, especially if adopted widely for the mass-market automobile sector. When PEMFC meet automotive cost targets, stationary power generation application could also be benefited. The projected cost for fuel cell is about S\$ 1700 per kW (California Energy Commission, 2004). If this cost can be realised then the cost of electricity using natural gas would be 16.6 ¢/kWh_e.

4.6. Orimulsion-fired steam turbine

One of the power companies in Singapore, PowerSeraya, would be using Orimulsion fuel for power generation due to its cheaper price (PowerSeraya, 2004). Orimulsion is a liquid fossil fuel consisting of an emulsion of 70 % bitumen (a naturally occurring heavy petroleum material) from the Orinoco region of Venezuela, 30 % water, and a small amount of surfactant (United States Environmental Agency, 2001). The Orimulsion fuel is currently being used in many power plants around the world (Marruffo et al., 1998), although it would be used for the first time in Singapore. The power company is converting three 250 MW fuel oil-fired steam turbines to use the Orimulsion fuel by 2005. To account for the primary energy use, emissions and cost of electricity generation from the Orimulsion-fired steam turbine, a streamlined LCA was performed in addition to the LCCA.

4.6.1. LCA of Orimulsion-fired steam turbine plant

A hypothetical 250 MW Orimulsion-fired steam turbine plant was considered. The operational parameters of the plant were assumed as in the fuel oil-fired plant (see Section 4.2). For the base case, the net efficiency of 30 % was assumed. It is lower than the oil-fired steam turbine because the Orimulsion-fired plant would use additional pollution control equipment such as flue gas desulphurisation system, NO_x control systems and electrostatic precipitation. These equipment would require additional auxiliary power. The high moisture content of the Orimulsion fuel would also limit the combustion temperature.

Considering the limitations of data availability, only the energy use and emissions from the upstream processes and transportations of Orimulsion fuel were taken into account. As can be seen from the LCA of steam turbine and combined cycle plants, the hidden energy use and emissions are insignificant in the construction and

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decommissioning phases. It was also assumed that the extraction of Orimulsion fuel is similar to coal production. Energy use and emission data of coal production were adopted from Spath et al. (1999), which is about 3 % of the fuel produced.

The annual Orimulsion fuel demand was estimated based on its lower heating value of 28 MJ/kg. The CO₂ emission factor of the Orimulsion was estimated as 78.6 t-CO₂/TJ based on its carbon content (United States Environmental Agency, 2001). Since there is no CH₄ emission in coal production (Spath et al., 1999), it was ignored. The N₂O emission in the operational phase was assumed as in the fuel oil-fired steam turbine plant.

4.6.2. Life cycle energy use and GWP

The primary energy use per functional unit is estimated to be about 13.3 MJ_f/kWh_e. Transportation accounted for about 7 % of the life cycle energy use and the hidden energy use is about 10 %. The GWP of electricity generation from the Orimulsion-fired steam turbine plant is about 1049 g-CO₂/kWh_e. The hidden emissions accounted for about 11.2 %. Even though the energy use and emissions from the upstream process are very small, the transportation energy accounted for a significant portion of the hidden energy use and emissions. It is because the Orimulsion fuel has about 30 % water and it would be imported from Venezuela by ships.

Like in the LCA of oil-fired and gas-fired plants, correlations are established between plant net efficiency and life cycle energy and GWP and are presented in Equations (4.5) and (4.6).

$$[\text{Life cycle energy use}]_{\text{Orimulsion plant}} = 4.002 \eta^{-0.9979} \text{ MJ}_f/\text{kWh}_e, \quad (4.5)$$

$$[\text{Life cycle GHG emission}]_{\text{Orimulsion plant}} = 316.7 \eta^{-0.997} \text{ g-CO}_2/\text{kWh}_e, \quad (4.6)$$

4.6.3. LCCA of Orimulsion-fired steam turbine plant

The capital cost data was adopted from the oil-fired steam turbine plant. However, additional costs were included for the pollution control equipments (Marruffo et al., 1998). The O & M cost was assumed as 5 % of the capital costs. The other cost factors were the same as in the earlier LCCA. As far as the price of Orimulsion fuel is concerned, it is estimated to be about 38 % of the fuel oil price on weigh basis (Marruffo et al., 1998; Latin Petroleum, 2004). On energy basis, it works out to about 56 % of the fuel oil price. In the LCCA, Orimulsion fuel price of S\$ 120 per tonne was used.

The cost of electricity generation is calculated as 8.82 ¢/kWh_e. About 65 % of this cost accounts for fuel use while the capital and O & M costs are accounted for 21 % and 14 %, respectively. The higher capital cost is due to additional pollution control equipments. The variation of cost with respect to the plant efficiency and Orimulsion price is shown in Figure 4.21.

Fig. 4.21. Cost of electricity generation from Orimulsion-fired plant

4.7. Summary

The LCA of the oil/Orimulsion-based power generation reveals that hidden processes, such as fuel upstream processes and transportation consume about 8-10 % additional energy on top of the fuel embedded energy while the hidden GWP is about 9-12 %. In gas-fired combined cycle plants, the hidden processes account for 8 % and 18 % of the life cycle energy use and GWP, respectively. Although there is no energy use and emission from the operational phase of solar PV system, its construction phase consumes significant portions of energy. Its specific energy use and emissions are about 20-35 % of fossil fuel based electricity generation. Therefore, the inclusion of LCA is necessary in accounting for environmental impacts of power generation technologies.

Electricity from gas-fired combined cycle plants is cost effective and its GWP is also relatively low. Electricity from oil-fired plants has a higher GWP while its cost is intermediate. The cost of electricity from Orimulsion-fired plants is comparable to gas-fired plants although its GWP is the highest among the selected technologies. In solar PV based power generation, the GWP is less than one-fourth/fifth of that from the oil/Orimulsion based power generation or half of the gas-fired combined cycle plant. However, its cost is extremely high. Electricity from fuel cell technology is not comparable either from its cost or emission perspectives due its immature technology. Selecting the best source of power generation depends on the national policy relevance and is a challenging task.

The results presented in this chapter are based on the operational parameters defined in each of the case studies. However, any of these operational parameters can be changed in the model and their output can be obtained. Using these LCA and LCCA models, various power generation scenarios are studied in Chapter 7.

5. Bottom-up Approach – Case Studies

5.1. Introduction

As described in Section 2.4.1, the potential energy efficiency options in the bottom-up approaches are categorised as:

- (i) Demand side management (DSM) (e.g. energy services, labelling and standards, etc.)
- (ii) Improving electricity generation efficiency (e.g. auxiliary power reductions, operational changes, etc.)
- (iii) Synchronising electricity generation and end-use application (e.g. cogeneration - combined production of power and heat/cooling)

For this study, a district-cooling service (DCS) was chosen as a bottom-up measure to develop a model to analyse DCS. As another bottom-up measure, cogen is selected and its energy saving methodology is established. These are used in the integrated framework of power generation planning (see Section 7.5). This chapter describes the LCA and LCCA of Singapore's first commercial DCS plant and the results are compared with building specific cooling systems (BSCS). It is aimed to quantify the saving potential of primary energy use, GHG emissions and the costs of DCS. The methodology of cogen model is also described in this chapter.

5.2. District cooling service

In Singapore, air-conditioning has been estimated to account for about 60 - 70 % of a building's electricity use (Jayamaha, 2004) and one-third of the country's total electricity consumption (Sadavisan, 2002). Buildings are typically equipped with one or a number of electric driven chillers or air conditioners. The building specific cooling systems (BSCS) are often oversized and operated on part-load which leads to higher

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electricity consumption. In addition, O & M practices are inadequate and configuration of chiller, pump, cooling tower and control systems mismatched (Jayamaha, 2004; Foo and Ramany, 2004; Tay, 2004). Thus, the BSCS tend to be inefficient.

District cooling service (DCS) is a centralised production of chilled water or other medium, which is supplied to multiple buildings through a network of insulated pipes. DCS is a well-established energy service in the USA, Europe, Sweden, Middle East and Japan (Metz and Margen 1987; Westin, 2001; Safi, 2004). DCS has many advantages over BSCS, which are summarised in Table 5.1. Despite the huge demand for air-conditioning in Singapore, DCS has not yet been fully exploited. In recent years, the Singapore government is promoting DCS and mandated its use in Marina South, which is a new commercial complex being developed (EMA, 2002a).

Singapore's first commercial DCS plant commenced its operation in 2000 to serve Changi Business Park while the second of its kind serves a premier R&D complex, Biopolis (Lee, 2003). These DCS plants use electric driven vapour compression chillers to produce chilled water. A primary motivation for these DCS facilities is to use of off-peak tariffs of electricity during nights. Thus, chilled water is produced during the night and stored in insulated tanks, and supplied during the day, especially for peak cooling demands. The thermal storage system serves to reduce the required installed capacity of chillers and minimise the peak electrical demand, thereby bringing additional economic benefits. Despite its high capital costs, the system appears to be economically feasible. Primarily due to the tariff difference and reduced peak electrical demand. In order to evaluate its impact on energy efficiency, emission reduction and cost effectiveness, LCA and LCCA were performed and results were compared with BSCS.

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Table 5.1. Comparison of DCS versus BSCS

	DCS
Chiller system	<ul style="list-style-type: none"> ➤ Bigger chillers tend to be more efficient than smaller chillers ➤ Designed/full load operations of chiller system are efficient than part-load operations in BSCS ➤ Enhanced O & M practices and regular preventive maintenance improves the efficiency ➤ Centralised handling of refrigerants minimise refrigerant emission ➤ Reduced chiller reserve capacity (about 70 %) (see Section 5.4.1)
DCS with thermal storage	<ul style="list-style-type: none"> ➤ Reduce the required chiller installed capacity (about 40 %) (see Section 5.4.1) thereby reducing capital costs ➤ Decrease the peak electrical power demand ➤ Night time operation of chiller increases the efficiency due to cooler ambient air and lower condenser temperature
Indirect benefits	<ul style="list-style-type: none"> ➤ Reduce the peak electrical load demand (about 30 %) ➤ Reduce the difference between peak load and off-peak loads, thereby improves overall electricity generation efficiency ➤ Potential to decrease the peak tariff of electricity price ➤ Reduce/delay power grid expansion due to lesser peak power demand
Future perspectives	<ul style="list-style-type: none"> ➤ Natural gas based distributed cogen (combined power and cooling) ➤ Recovery of waste heat from power plants for the cooling application
Disadvantage/negative aspects	<ul style="list-style-type: none"> ➤ Additional thermal energy losses and leakages in T&D and storage of chilled water ➤ High capital costs for pipe reticulation and storage systems ➤ Increase demand for off-peak power that may increase the off-peak electricity tariffs

5.3. Building specific cooling systems

To demonstrate DCS as a energy efficiency based bottom-up measure, it should be compared with a ‘typical’ BSCS. However, there is nothing like a ‘typical’ installation of BSCS. Every chiller plant is unique depending on building’s age, load profile, chiller configuration, auxiliary equipment, O & M practices, etc. The chiller

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efficiency/Coefficient of Performance (*CoP*) could be compared. However, it is not only the chiller efficiency but the overall operational performance of chiller system that is important. In commercial chiller systems, chillers account for about 58 % of the total electricity use while pumps and cooling towers account for 26 % and 16 %, respectively (Trane, 2004).

The fundamental difference between chiller systems in DCS and BSCS is the actual operating conditions. Chillers in a DCS plant operate at their designed/full load capacity regardless of the cooling load. In BSCS, operating load varies with the cooling load. Only during the peak cooling loads, will the chiller in a BSCS be operating near its rated capacity. Most of the time, the chillers run at part-load thereby consuming more energy for a unit cooling output (Tay, 2004). Therefore, the part-load performance of the chiller is very important in the BSCS. Recent design breakthroughs have yielded dramatic improvements in the part-load efficiency such that the part-load efficiency of centrifugal chillers is only slightly below the full-load efficiency (Natural Resources Canada, 2002).

The chillers in a DCS could be more efficient than chiller in the BSCS due to their bigger size. The average efficiency of chiller plant in Singapore is between 0.85 and 1 kW/RT. Many new/retrofitted chiller plants operate between 0.8 and 1.0 kW/RT (Premas International, 2002). In case of air-cooled chillers, the efficiency is far lower than water-cooled chillers. They are in the range of 1.2 to 1.45 kW/RT.

To optimise the part-load operation of chiller, various configurations and controls are being used. Trane (1996) and Carrier (2004) described detailed configurations of chillers and their part-load operational performances. In Singapore, the $(n+1)$ chiller configuration is commonly used in the design of a chiller plant where n is the number of primary chillers installed based on the peak cooling demand. The

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additional chiller is used as back-up (reserve capacity) chiller (Leong, 2004a). The back-up chillers are installed to cope with continuous operation during maintenance/emergency shut-downs of primary chillers. For example, for a peak cooling demand of 1200 RT and depending upon the cooling load profile, a (3+1) configuration with four chillers each of 400 RT capacity or a (4+1) configuration with five chillers each of 300 RT capacity would be installed. Therefore, to compare the part-load performance of BSCS with DCS, chiller configuration and control system in a multi-chiller system are also important. Foo and Ramany (2004) and Tay (2004) presented case studies on inefficient chiller systems due to mismatched operations of chillers and cooling towers.

In BSCS, a wide range chillers, from water-cooled to air-cooled chillers, with unit sizes of a few refrigeration tons (RT) to few hundred RT are being used in BSCS. There is no exhaustive database available for chiller technologies used in Singapore. Considering the great diversity of chiller system in BSCS, it is difficult and debatable to describe a 'typical' installation of BSCS. Thus, in this study to compare DCS with BSCS, no specific BSCS was selected. A hypothetical BSCS has been chosen and LCA and LCCA are performed. However, operational parameters were assumed based on the actual operations of BSCS (Premas International, 2002; Jayamaha, 2004; Foo and Ramany, 2004; Leong, 2004; Tay, 2004; Leong, 2004a). The LCA-LCCA model of BSCS is developed in such way so as to consider (n+1) chiller configuration or a 20 % redundancy factor.

5.4. LCA-LCCA of DCS

5.4.1. The DCS plant

The DCS plant has been designed with four chillers each of 2000 RT (three primary chillers and one back-up/reserve chiller) and two thermal storage system. The

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chillers are electrically driven vapour compression centrifugal chillers. The thermal storage systems are insulated concrete tanks each of 7500 m³ capacity. Its (chilled water) thermal storage capacity is 21,000 RTH and is equivalent to an installed capacity of 2000 RT. The three primary chillers and the two storage tanks are equivalent to an installed capacity of 10,000 RT. Since all the buildings do not reach their peak-cooling load at the same time, a 70 % diversity factor is used (Poh, 2004). Thus, the DCS plant could cater for a cooling demand of 14,000 RT. Chilled water is produced at 4°C and supplied to the customer at 7°C. The return water from the customer is at 14°C, which is mixed with the chilled water at 4°C to produce the supply water at 7°C. About 3 km pipeline (800 mm diameter) reticulations have been installed for chilled water supply. Heat exchangers are installed at the customers' station and its secondary loop is connected to the cooling loads via Air Handling Units (AHU). Figure 5.1 shows the layout of the DCS plant. Electricity for the DCS plant is purchased from the grid. The chillers and plant equipments are designed for 20 years while the building and pipe reticulation for 50 years.

The DCS plant is typically designed to operate throughout the day. During nights, chilled water is produced and charged in the storage tanks. During the day time, chilled water produced from the chiller and storage tank is supplied to the customer. The chilled water from the storage tank is specifically used for the peak cooling load. However, at the time of this study, day time operation of chiller was minimum due to inadequate DCS customers¹⁴. Therefore, operation was scheduled in such a way so as to supply the stored chilled water firstly independent of the cooling demand because it

¹⁴ At the beginning of this study, the DCS plant was not operating at its designed capacity due to inadequate customers. Firstly, two chillers and a storage tank were installed. The third chiller and the second storage tank were under installation. The fourth chiller would be installed after new customers signed up for the DCS.

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was produced at a cheaper cost using the off-peak tariffs. The typical chiller operation would begin when the customer demands increase to its designed capacity.

Fig. 5.1. Layout of district cooling plant

5.4.2. Goal and scope of this LCA

The goal of this LCA study was to estimate the primary energy use and GWP in providing the DCS. 1 RTH (refrigeration ton-hour) of cooling service delivered at the customer station was selected as the functional unit. The secondary loop of the customer station, i.e. AHU, was not included. Figure 5.2 shows the LCA boundary, which was drawn to account for all energy use and GHG emissions, including the refrigerant releases. In the construction phase, extraction and production/manufacturing of materials used in the plant equipment and pipe reticulation systems were included. In the operational phase, life cycle of electricity use and leakages/

purges of refrigerants were included. In the decommissioning phase, material recycling and disposal were included.

Fig. 5.2. LCA boundary of DCS

For this LCA, the lifetime of the chiller system was considered as 15 years¹⁵ and 45 years for the building and pipeline reticulations. Functional allocations were made in the LCA and LCCA to account for the variations in lifetimes.

5.4.3. Data sources

Primary data were obtained from the DCS plant. The operational phase data such as electricity consumption, chilled water production and DCS were from the

¹⁵ Based on manufacturer's specification, the efficiency of the chiller would decrease by 5 % during the first five years of operation. In subsequent years, the efficiency drop could be higher. A major overhaul was recommended in the 15th year to improve the chiller efficiency. It is likely that chiller system available in the market at that time would be more efficient than the overhauled chiller system. In such a case, a new chiller would be a better choice in terms of energy and cost-effectiveness. Bearing this in mind, the service lifetime of the chiller system was assumed as 15 years, though it would be used for 20 years.

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operation of the two-chiller systems and one storage tank. These data were extrapolated to the designed capacity of the DCS plant (four chillers and two storage tanks). Data such as specific energy requirement for material and emission factors were adapted from literature (GEMIS, 2002).

The material inventory was established from the actual weight of the plant equipment such as chiller, motor, pump, and fan. The weights of metals were estimated based on the metal composition of the equipment (Gheewala and Nielsen, 2003, Gheewala, 2004). The weight of concrete used for the storage tanks, steel used for pipe reticulation and internal piping, insulations (polyethylene) were estimated. Since the lifetime of the pipe reticulation and building was taken as 45 years, only a one-third of their materials were accounted for in the life cycle inventory.

Energy required for extraction and production of metals was taken from GEMIS (2002). Energy requirement for the production of (low density) polypropylene insulation was 84.8 MJ_t, which includes the energy content of the feedstock, 52.72 MJ/kg (Boustead, 2003). The chillers were charged with R123 refrigerant of 1.8 tonnes per chiller. In addition to refrigerants charged in chillers, refrigerant losses occur at the initial, operating/intermittent and disposal stages of the chiller (Calm, 1999). A 1 % venting loss at the time of charging and disposal was assumed (LEED, 2004). The make-up refrigerants consumed in the operational phase was estimated as 90 kg per chiller in every three years. This worked out to an annual loss of 1.7 % of the initially charged refrigerant compared to 1 % in LEED (2004). These make-up refrigerants were accounted in the material inventory and emission inventories, as refrigerant-R123 is also a greenhouse gas. The energy requirement for production R-123 was assumed to be that of R-123 of 260 MJ/kg (Frischknecht, 1999).

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In the operational phase, about 90 % of the chilled water produced from the chiller was supplied (energy service) to the customer. 5 % of the chilled water was used within the DCS plant to cool power transformers, control rooms and office building. The thermal energy loss in storage and T&D of chilled water was about 0.16 % and 1.8 %, respectively. The remaining was assumed as the leakages and internal losses. Figure 5.3 shows the chilled water balance.

Fig. 5.3. Chilled water balance of DCS plant

The annual average efficiency of the chillers was measured as 0.64 kW/RT (CoP of 5.5). The efficiency of the DCS plant was 0.96 kW/RT (CoP of 3.7), which is the ratio of total chilled water produced to the total electricity consumed in the DCS plant. Figures 5.4 shows the distribution of electricity consumption in the DCS plant. The chiller account for 66 % of the total electricity use and the pumps and cooling towers accounted for 11 %. The chilled water distribution pumps accounted for about 9 % of the plant’s total electricity consumption. The net efficiency of the DCS plant was 1.06 kW/RT (CoP of 3.3), which is the ratio of cooling service delivered at the customer station to the total electricity consumed in the DCS plant.

Fig. 5.4. Distribution of electricity consumption in DCS plant

From the chilled water usage pattern of the DCS customers, a weighted average duration of chilled water supply was estimated as 2005 hours per year at their rated cooling load. Based on this value, the annual operational hour of the chiller system was calculated as 4678 hours $\{(14,000 \text{ RT} * 2005 \text{ h}) / (3 * 2000 \text{ RT})\}$. Using this value and *CoP* of the DCS plant, the electricity demand for the entire operational lifetime of 15 years was estimated. An annual average degradation in chiller performance of 1.25 % was used. The primary energy use of electricity generation was accounted as 8.82 MJ/kWh_e based on generation mix in 2003 (see Section 7.3).

In the decommissioning phase, it was assumed that about 70 % of metals would be recycled with a recovery rate of 90 %. However, the steel used for the pipe reticulation was not considered for the recycling as the underground pipelines might not be fully recovered. The concrete debris and rest of the materials would be land filled. About 50 % of the insulation materials was assumed to be incinerated and its feedstock thermal energy equivalent was credited in the energy balance. It was assumed that 90

% of the refrigerant would be recovered from chillers and their energy equivalent was also credited in the energy balance.

Though there is no direct GHG emissions occur from the DCS plant, indirectly they occur from the use of electricity and other materials like, refrigerants, insulations, etc. The life cycle GWP of electricity generation in Singapore was 610 g-CO₂/kWh_e based on the generation mix in 2003 (see Section 7.3). GHG emission from the production of insulation (polyethylene) was 1.86 kg-CO₂ equivalents (Boustead, 2003). Emission from the production of refrigerant R123 was assumed to be that of R-134a of 7.7 kg-CO₂/kg (McCulloch and Lindley, 2003). For the directly released refrigerants, the GWP of 90 kg-CO₂/kg was used (Calm et al., 1999). For the other energy related emission, average emission factors of coal, oil and gas were used (van Margreet et al., 1994; IPCC, 1996c).

5.4.4. Life cycle energy use and GWP

The life cycle primary energy use of DCS is calculated as 10.09 MJ/RTH and Figure 5.5 shows its distribution. The electricity use accounted for 97.5 % of the life cycle energy use. The construction phase accounted for about 1.6 % of the life cycle energy use, which is mainly from pipe reticulation systems.

The life cycle GWP of DCS is 704 g-CO₂/RTH. The distribution of GWP of DCS is shown in Figure 5.6. The refrigerant release accounted for less than 0.1 % of the life cycle GWP because the GWP of R123 is very low. In addition, its unnecessary emissions are minimised due to the centralised handling of refrigerants by trained professionals and regular preventive maintenance. If the refrigerant were to be R134a, then the GWP of DCS would be 710 g-CO₂/RTH and the refrigerant's share would be about 0.88 %.

Fig. 5.5. Distribution of life cycle energy use in DCS

Fig. 5.6. Distribution of GWP in DCS

5.4.5. LCCA of DCS

The capital cost of the DCS plant was about S\$ 40 million, including the cost of the fourth chiller. Figure 5.7 shows the distribution of the capital costs. For the capital costs, an annual interest rate of 5 % payable over the lifetime of the plant was used in the LCCA. The expected lifetime of the buildings and pipe reticulations was 45 years while for the chiller system, storage tanks and customer station were 15 years. To account for the variations in lifespan, 15-year and 45-year LCCA were performed.

In the 15-year LCCA, the capital costs with 45 years lifetime such as the pipe reticulation and buildings, were annualised and its 15 years of annualised cost were

accounted in the LCCA using Equation (3.14). The rest of the capital cost were accounted as actual cost.

Fig. 5.7. Capital cost distribution of the DCS plant

In the 45-year LCCA, it was assumed that the new chiller systems, storage tanks and customer station would be installed after the end of life of the existing equipment. Thus, two repeated capital costs, which would occur in the 16th and 31st years, were included in the LCCA. In the 45-year LCCA, two cases of LCC were calculated. Firstly, the repeated capital costs were considered as a replacement cost [see Equation 3.15)]. Thus, no interest for the repeated capital was accounted. Secondly, the repeated capital costs were accounted with an annual interest rate using Equation (3.15).

For the operational phase, the electricity and O & M costs of the existing facilities were obtained from the DCS plant. The electricity costs were extrapolated to the designed capacity of the DCS plant. The demand power cost¹⁶ of S\$ 103,144 per MW per year and the electricity price of S\$ 88.47 per MWh were used in the LCCA. The O & M cost included were the cost of labour, scheduled maintenance, spare parts,

¹⁶ Electricity cost was derived from purchased price from the deregulated market at special tariffs, including all taxes and services charges

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and consumables such as refrigerants and water. The O & M cost was estimated to be about 1.7 % of the capital cost of the chiller systems. The electricity and O & M costs were accounted with an annual escalation rate of 2 %. It is likely that the chillers and control systems installed in the future would be more efficient than the existing plant. Therefore, their electricity demand could be lesser. In the 45-year LCCA model, provisions were made to account for any such improvement in chiller efficiency (see Section 5.4.5.2).

In the decommissioning phase, the costs would be incurred in dismantling the equipments and for the disposal. The decommissioning and disposal cost of 2 % of the capital cost and the salvage value of 1 % were considered in the LCCA. For the LCCA, a discount rate of 2 % was used.

5.4.5.1. Cost of DCS

In the 15-year LCCA, the cost of DCS is calculated as 42.4 ¢/RTH. Figure 5.8 shows the LCC distributions. The capital cost accounted for 66 % of the DCS while the electricity accounted for 29 %. However, in BSCS, it is about 30 % (see Figure 5.13).

Fig. 5.8. LCC distribution in 15-year LCCA of DCS

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In the 45-year LCCA, the LCC of DCS is about 29.1 ϕ /RTH without including the interest for the repeated capitals [based on Equation (3.15)]. The 45-year LCCA by accounting the interest for the repeated capital [using Equation (3.15a)], the LCC of DCS is 29.9 ϕ /RTH. Figure 5.9 shows their LCC distribution. The capital cost accounted for about 50-52 % while the electricity cost is about 42 %.

Fig. 5.9. LCC distribution in 45-year LCCA of DCS

5.4.5.2. Sensitivity analysis

A sensitivity analysis was performed to see the effects of key parameters that affect the LCC of DCS. The LCC of DCS presented in the previous section is used as the based case for comparison.

The capital cost was the major share in the LCC of DCS. Therefore, the interest on capital is a key factor that affects the DCS cost. If the interest rate is 7 % compared to 5 % in the base case, the 45-year LCC of DCS would become 32 ϕ /RTH and 50 ϕ /RTH in the 15-year LCCA.

If the chiller systems would serve for 20 years and the pipe reticulation for 60 years, then the 20-year LCC of DCS would be about 39.9 ϕ /RTH while the 60-year LCC would be 27.1 ϕ /RTH at 5 % interest rate.

If the subsequent new chiller system installed in the 16th and 31st years would be 10 % efficient than the existing chiller systems, then the 45-year the LCC of DCS would be 24.7 ¢/RTH compared to 29.1 ¢/RTH in the base case.

The variation in degradation of chiller system performance between 1 to 2 % would affect the DCS price by 0.5 ¢/RTH.

5.5. LCA-LCCA of BSCS

As described in Section 5.3, a hypothetical BSCS was chosen to perform the LCA and LCCA. For the BSCS, a peak cooling demand of 1000 RT and a chiller installed capacity of 1200 RT (20 % redundancy) were used. The chiller system comprises three-screw type chillers of 400 RT operating with R134a refrigerant. The functional unit of 1 RTH of chilled water produced from the chiller system was used so that it can be comparable with the DCS delivered at the customer station.

5.5.1. Data sources

For the material inventory, the specific weight of the metal use was adopted from Gheewala and Nielsen (2003). The specific weight of the refrigerant used in the chiller was estimated to be 1.25 kg/RT (Trane, 2003; Dunham-Bush, 2002). The energy use and emission data were from the same sources as those in the DCS plant. The GWP of R134a was 1300 g-CO₂/kg (Calm et al., 1999).

The lifetime of the chillers systems was assumed as 20 years¹⁷. The efficiency of chillers was assumed as 0.8 kW/RT. The power demand for auxiliary equipments was considered as 30 % of chiller power demand (Bradford et al., 2001; Trane, 2004).

¹⁷ It is very common in BSCS to use the chillers for longer time, even if it consumes a lot of electricity. This is because of the high capital costs for retrofitting or replacement.

For part-load operation of the chillers, the integrated part-load value¹⁸ (IPLV) of chiller system was estimated based on a screw type chiller performance curve (load versus CoP) (Trane, 1996; ARI, 1998; Bradford et al., 2001). The average duration provided by the DCS to the customers was 2005 hours per year¹⁹ at the rated cooling demand. A chiller performance degradation factor 2 % per year was also used in the calculations because of high fluctuations in operational load of BSCS. A 5 % chilled water losses accounted for leakages in the chiller system.

In the decommissioning and disposal phase, it was assumed that 50 % of the recyclable material would be recovered and recycled with 90 % recovery rate. The rest of the materials would be land filled.

5.5.2. Life cycle energy use and GWP

The life cycle primary energy use of chilled water production from the BSCS is about 11.88 MJ/RTH. Figure 5.10 shows the distribution of the life cycle energy use. The construction phase accounted for about 0.5 % as compared to about 1.6 % in the DCS plant. In the DCS plant, pipeline reticulation and storage tanks contributed to relatively high-energy use in the construction phase.

The GWP of chilled water production from the BSCS is 850 g-CO₂/RTH and its distribution is shown in Figure 5.11. The refrigerant release accounted for about 3.1 %, which is higher than from the DCS plant of 0.1 %. This is because of the high GWP of R134a refrigerant. If the refrigerant were to be R123 then the life cycle GWP of BSCS

¹⁸ The Air Conditioning and Refrigeration Institute (ARI) developed a standard that incorporates part-load performance of chillers. Part-load efficiency of chiller is expressed by a single number called the integrated part-load value (IPLV), based on average criteria. The weighing factors for IPLV at the 25 %, 50 %, 75 % and 100 % loads are 0.12, 0.45, 0.42 and 0.01, respectively (ARI, 1998).

¹⁹ Based on Trane (1996) the weighted annual average load factor of most commercial chiller systems in the USA was 43.9 % for an annual operational hours of 6489, i.e. 2848 hours per year.

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would be 825 g-CO₂/RTH and the refrigerant’s share would be only 0.24 %. If the refrigerant were to be R22, then the GWP would be still higher than R134a.

Fig. 5.10. Distribution of life cycle energy use in BSCS

Fig. 5.11. Distribution of GWP in BSCS

Since a wide range of chillers systems are being used in conventional BSCS, the life cycle energy use and GWP would vary widely. Figure 5.12 shows the variation of the life cycle energy use and GWP with respect to the *CoP* of the chiller. It is only for a relative comparison with the DCS. Its absolute values depend on primary energy use and GWP of electricity generation and the type of refrigerant used in the chiller system.

Fig. 5.12. Life cycle energy use and GWP in BSCS

5.5.3. LCCA of BSCS

The specific capital cost of the BSCS was considered as S\$ 2500 per RT (Leong, 2004). The demand power charge and electricity prices were based on the regulated market price of S\$ 84,480 per MW per year and S\$ 131 per MWh (peak) and S\$ 77 per MWh (off-peak) (Singapore Power, 2004a). Based on chilled water consumption profile of the DCS customers, the night time load was about 5 %, as most of the office and commercial buildings require cooling during the peak tariff hours. Therefore, for electricity tariff, a 95 % peak and 5 % off-peak tariff price were used in the LCCA.

The annual O & M costs were estimated to be about S\$ 204 per RT of installed capacity based on five BSCS in different types of buildings in Singapore (Leong, 2004). The O & M cost include the labour cost, maintenance cost, spare parts and water consumption. It is almost double that of the DCS plant because of high manpower and inventory costs for spare parts. However, they could vary significantly with the size of the BSCS. The decommissioning and salvage values were assumed to be the same as in the DCS plant.

The LCC of chilled water production is calculated as 52.5 ¢/RTH. Figure 5.13 shows the cost distribution of chilled water production. The cost of electricity accounted for 45 %. The capital cost accounted for 30 % as compared to 53 % in the DCS plant. The O & M costs accounted for 25 % whereas it is about 8 % in the DCS.

Fig. 5.13. LCC distribution of chilled water production in BSCS

5.6. Results and discussion - DCS versus BSCS

Table 5.2 summarises the life cycle primary energy use, GWP and the costs of DCS and chilled water production in BSCS of the above case studies. It can be seen that there are about 15 % savings in primary energy use and 17 % emissions in the DCS. However, to compare DCS and BSCS, careful consideration should be given to choose the right systems. Since there is no established data on typical BSCS and considering the great diversity of chiller technologies used for BSCS, it is difficult to generalise the results based on the above case study. However, there remains a potential to save energy and emissions in DCS. Though the data and assumptions of the DCS plant are reliable, the BSCS data are debatable. If the same chiller efficiency (CoP) is used for the BSCS and DCS, there is a potential to save about 5.5 % in primary energy and 6 % in emissions. They are mainly resulted from the full load operation of chiller systems in the DCS plant. The actual saving from full load

operation of chillers in the DCS plant could be higher. However, a part of the energy is used in the distribution pumps and losses in T&D of chilled water.

Table 5.2. Life cycle energy, emission and cost - DCS versus BSCS

Cooling system	Primary energy (MJ/RTH)	GWP (g-CO ₂ /RTH)	LCC (¢/RTH)
DCS	10.1	704	42.4*
BSCS	11.9	850	52.5
Savings	15 %	17 %	19 %

* 15-year LCC (see Section 5.4.5.1)

There are indirect benefits from the DCS that would contribute to improving the overall energy efficiency of power generation system. For example, Singapore’s diurnal electrical demand is largely due to cooling load. The electricity generation for the peak load used to be less efficient and costlier than for the off-peak load. This is due to their high start-up energy, part-load operations, under utilisation of the installed power capacity, etc. The DCS plant with thermal storage can shift a part of the peak electrical demand to night thereby reducing the large difference (see Figure 7.5) between the peak and off-peak electrical demand. As the result, the energy efficiency of electricity generation for peak load application could be improved. The expansion plan for power grid extension would also be avoided or delayed.

Since the technical know-how, operational practices, control system, etc. of the DCS are demonstrated, alternative sources of energy/fuel for DCS plant should be explored. For example, natural gas based cogen could be used as distributed DCS. The lessons learnt from the DCS plant can be effectively used for the exploration of low-grade waste heat available from the power plants. Since commercial buildings account for 37 % of the total power consumption (see Section 7.2.1), it would be an effective

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strategy for power management and the power grid expansion for the future growth. Due to time limitation, these are not studied in this research.

From Table 5.2, it can be seen that DCS is about 19 % cheaper than BSCS. A further parametric analysis was performed to compare the costs of DCS and BSCS.

If chillers of the same efficiency were to be used for the DCS and BSCS, then the cost of chilled water production in the BSCS would be reduced to 48 ¢/RTH, which is about 12 % higher than the DSC.

Yet another reason for the cheaper cost of DCS is the use of off-peak electricity tariffs. If the demand for off-peak power is increased in the near future due to more penetration of DCS, then the off-peak tariff price can also increase. At the same time, it is possible that the peak tariff can decrease. Any such changes would affect cost of DCS and it may favour to BSCS. If the peak electric tariff were to be used for DCS then the cost of DCS would be 53.8 ¢/RTH, which is 2 % higher than BSCS. This is due to the high capital cost in the DCS. On the other hand, if the off-peak tariff were to be used in BSCS then the cost of chilled water production in BSCS would be 44 ¢/RTH (CoP of chiller is also same as in the DCS plant), which is still 4 % higher than the DCS. This is attributed to higher electricity use in the BSCS. However, the use of off-peak tariff in BSCS would be possible only when BSCS use a thermal storage system. If thermal storage system were to be installed in BSCS, then its part-load efficiency would also improve and eventually there would not be any significant difference between the BSCS and DCS. Perhaps, the thermal storage system in BSCS would be more energy efficient and cost effective than DCS.

Since the DCS plant requires high capital cost, capital availability would limit the penetration of DCS. However, capital can still be available at a higher interest rate. If the interest rate on capital cost of DCS plant is increased to 7 % then the DCS in a

15-year LCCA would be 50 ¢/RTH. This is 4 % higher than that in a BSCS for the same chiller system efficiency.

In Singapore, about 22-26 % of the country's total electricity is used for air conditioning of buildings in the commercial/service sector. This sector would be the potential²⁰ user of the DCS and there could be a substantial potential to reduce the energy use thereby emission. However, there is no data available to perform such study. Thus, for the bottom-up model, some scenarios are developed and their impacts are studied using the integrated framework (see Section 7.5.1).

5.7. Cogeneration

Cogeneration (cogen) is yet another option in bottom-up approaches of power generation planning. The Sub-Committee on Manufacturing (2002) of Singapore's Economic Review Committee had highlighted the importance of cogen from energy and economic perspectives. Cogen is a combined production of electricity and steam (for heating or cooling applications). Its operation is like a combined cycle plant with gas turbine (GT) and heat recovery steam generator (HRSG). However, the steam from the HRSG would be directly used for heating or cooling, via absorption chillers, instead of using in the steam turbine.

The steam produced from a cogen plant could be more efficient than that from a industrial boiler using fuel oil or gas. The net energy saving potential depends on the trade-off between the efficiencies of the cogen plant and industrial steam production. In the bottom-up model, the primary energy savings are quantified by comparing the electricity generated from cogen plant with a combined cycle plant. The energy saving

²⁰ In residential sector, about 30 % of the electricity is used in air conditioning (EMA, 2002b). However, it might not be energy efficient and cost effective to target those consumers for DCS.

estimation methodology described in this section is used in the integrated scenario studies of Section 7.5.

5.7.1. Energy saving estimation methodology in cogen: Heat

Let E_e be the electricity generated from a cogen plant that would otherwise be generated from a combined cycle plant. Therefore, the difference between the primary energy use/emission in the cogen plant and combined cycle plant is accounted as saving potential.

Primary energy demand to produce E_e from a combined cycle plant is given by

$$E_t^{cc} = \frac{E_e}{\eta_{cc}} \quad (5.1)$$

where η_{cc} is the net efficiency of the combined cycle plant which can be written as

$$\eta_{cc} = \eta_{GT} + (1 - \eta_{GT})\eta_{HRSG}\eta_{ST} \quad (5.2)$$

where η_{GT} , η_{HRSG} and η_{ST} are efficiencies of gas turbine, HRSG and steam turbine of the combined cycle plant, respectively.

If the E_e is generated from a cogen plant, its primary energy is equal to the gas input to the gas turbine of the cogen plant.

$$E_t^{GT} = \frac{E_e}{\eta_{GT}} \quad (5.3)$$

For the input energy of E_t^{GT} , the cogen plant also produces steam from its HRSG.

$$E_{\text{Steam}} = \frac{E_e(1 - \eta_{GT})\eta_{HRSG}}{\eta_{GT}} \quad (5.4)$$

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where E_{Steam} is the energy (enthalpy) of steam produced from the HRSG of the cogen plant.

If the steam produced from the cogen plant is assumed to replace that produced by an industrial boiler, then the net primary energy use in the cogen plant is

$$E_t^{\text{Cogen}} = E_t^{\text{GT}} - E_t^{\text{Boiler}} \quad (5.5)$$

where E_t^{Boiler} is the primary energy input to the boiler to produce E_{Steam} or the primary energy equivalent of steam produced from the cogen plant.

If E_{Steam} is produced from a boiler with an efficiency of η_B , then the primary energy input to the boiler is

$$E_t^{\text{Boiler}} = \frac{E_{\text{Steam}}}{\eta_B} \quad (5.6)$$

From Equations (5.4) and (5.6)

$$E_t^{\text{Boiler}} = \frac{E_e(1 - \eta_{\text{GT}})\eta_{\text{HRSG}}}{\eta_{\text{GT}}\eta_B} \quad (5.7)$$

From Equations (5.3), (5.5) and (5.7)

$$E_t^{\text{Cogen}} = \frac{E_e}{\eta_{\text{GT}}} - \frac{E_e(1 - \eta_{\text{GT}})\eta_{\text{HRSG}}}{\eta_{\text{GT}}\eta_B} \quad (5.8)$$

In the both combined cycle and cogen plant, the total electricity generation is E_e . However, in the cogen plant, additional steam is produced. Therefore, net primary energy saving from the cogen plant is

$$\Delta E_t = E_t^{\text{CC}} - E_t^{\text{Cogen}} \quad (5.9)$$

From Equations (5.1), (5.8) and (5.9)

$$\Delta E_t = \frac{E_e}{\eta_{CC}} - \frac{E_e}{\eta_{GT}} + \frac{E_e(1-\eta_{GT})\eta_{HRSG}}{\eta_{GT}\eta_B} \quad (5.10)$$

$$\Delta E_t = E_e \left(\frac{1}{\eta_{CC}} - \frac{1}{\eta_{GT}} + \frac{(1-\eta_{GT})\eta_{HRSG}}{\eta_{GT}\eta_B} \right) \quad (5.11)$$

Therefore, the primary energy saving per unit of electricity generated from a cogen plant instead of a combined cycle plant is given by

$$\frac{\Delta E_t}{E_e} = \left(\frac{1}{\eta_{CC}} - \frac{1}{\eta_{GT}} + \frac{(1-\eta_{GT})\eta_{HRSG}}{\eta_{GT}\eta_B} \right) \quad (5.12)$$

Equation (5.12) reveals that the higher the efficiency of the combined cycle plant and boiler, the lower the energy saving from the cogen plant. For example, if the efficiencies of combined cycle plant, gas turbine, HRSG and boiler are 55 %, 38 %, 70 % and 80 %, respectively, then the primary energy savings from each unit (kWh) of electricity generated from the cogen plant (instead of combined cycle plant) is about 0.57 kWh.

Equation (5.12) is used in the integrated framework to quantify the primary energy saving from a cogen based power generation. The energy saving resulted from a cogen plant can be credited either to the steam-consuming sector or to power sector or be distributed among them. However, due consideration should be given to avoid cross-sectoral emission credits. For this study, the energy savings are credited in the power sector.

5.7.2. Energy saving estimation methodology in cogen: Cooling

The steam produced from a cogen plant can also be used to drive an absorption chiller to produce cooling, e.g. chilled water. The overall energy efficiency of such cogen plant depends on the efficiency of heat driven (absorption/adsorption) chiller. For this study, a comparison is made between using steam to drive heat driven

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absorption chillers or to produce electricity as much as possible from the steam and use the electricity to drive a electric vapour compression chiller. The latter is similar to the electricity generation from a combined cycle plant which is then used for chilled water production in a electric chiller.

The cooling energy output of an electrical driven chiller is given by

$$E_c^{EC} = E_e CoP_{EC} \quad (5.13)$$

where E_c^{EC} is the cooling energy output from electric chiller. CoP_{EC} is the CoP of the electric chiller. E_e is the electrical energy input to the chiller.

If the electricity E_e is generated from a combined cycle plant, then from Equations (5.1) and (5.13)

$$E_c^{EC} = E_t^{CC} \eta_{CC} CoP_{EC} \quad (5.14)$$

where E_t^{CC} is the primary energy input to a combined cycle plant to produce E_c^{EC} and η_{CC} is the efficiency of the combined cycle plant.

In case of cogen, the electrical energy of the gas turbine would be used to run a electrically driven chiller while the steam from the HRSG would be used to run absorption chiller. The total cooling energy output from the cogen is given by

$$E_c^{Cogen} = E_t^{Cogen} (\eta_{GT} CoP_{EC} + (1 - \eta_{GT}) \eta_{HRSG} CoP_{AC}) \quad (5.15)$$

where E_c^{Cogen} is the cooling energy output from the cogen plant. E_t^{Cogen} is the primary energy input to the cogen plant. CoP_{AC} is the CoP of heat driven absorption chiller.

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For a unit primary energy input of E_t , cooling can be produced either from a cogen plant [Equation (5.15)] or from electric driven chillers [Equation (5.14)]. The additional cooling energy output between these two options is

$$\Delta E_c = E_c^{EC} - E_c^{Cogen} \quad (5.16)$$

From Equations (5.14), (5.15) and (5.16)

$$\Delta E_c = E_t^{EC} \eta_{CC} CoP_{EC} - E_t^{Cogen} (\eta_{GT} CoP_{EC} + (1 - \eta_{GT}) \eta_{HRSG} CoP_{AC}) \quad (5.17)$$

When, $E_t = E_t^{EC} = E_t^{Cogen}$ then

$$\Delta E_c = E_t ((\eta_{CC} - \eta_{GT}) CoP_{EC} - (1 - \eta_{GT}) \eta_{HRSG} CoP_{AC}) \quad (5.18)$$

In Equation (5.18), if ΔE_c is positive, then cooling through electrical driven chillers is more efficient than cogen. If ΔE_c is negative, then cogen-based cooling is more efficient. However, the cogen is not an energy efficient option while considering electricity generation efficiency and CoP of heat driven absorption chillers. With $\eta_{CC} > 55\%$, $\eta_{GT} = 38\%$, $\eta_{HRSG} = 80\%$, $CoP_{EC} > 5$ and $CoP_{AC} < 1.2$, cogen-based cooling is not energy efficient as $\Delta E_c > 0.25$. However, a detailed study should be carried out by considering cogen as a distributed DCS technology. Such a study should be performed in conjunction with the indirect benefits of DCS by accounting for the efficiency of peak load power generation, T&D losses and power grid development costs.

5.8. Summary

LCA and LCCA models are customised for DCS and BSCS. The LCA of DCS and BSCS reveal that DCS do have potential to conserve energy. If the same chillers were to be used for BSCS and DCS, there would be a potential to save about 5.5 % in

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primary energy and 6 % in emissions. These resulted mainly from the full-load operation of chiller systems in DCS plant. The actual energy savings from full-load operation is much higher. However, in DCS plant, additional energy is used for chilled water distribution pumps and thermal losses occurred in T&D. Therefore, if thermal storage system were to be installed in BSCS, its part-load operation can be minimised. In such a case, BSCS can be more energy efficient and cost effective than DCS. Therefore, the thermal storage system has also a major role to play in terms of shifting the peak electrical load to night times thereby improving the power generation efficiency. Using this DCS case study results, scenarios of bottom-up measures are constructed and used for the integrated power generation scenario studies (see Section 7.5).

Cogen is another option that synchronises the power generation and demand. An energy saving estimation methodology is established to compare electricity generation from a cogen plant and combined cycle plant. A similar methodology is also developed to compare production of cooling energy from a cogen plant and conventional electrical driven chillers. They are used in the integrated power generation scenario studies.

6. Exergy - LCA in Integrated Approaches

6.1. Introduction

Inclusion of exergy analysis in LCA could yield useful information about the utilisation of energy resources during the life cycle phase. This would facilitate the search for alternative energy sources thereby minimising exergy destruction. This chapter aims to show how significant exergy analysis can be in the integrated approach. An ELCA is performed for the oil-fired steam turbine and gas-fired combined cycle plants. In Sections 6.3 and 6.4, streamlined LCA and ELCA are also performed for hypothetical energy demands. The results are used to highlight their relevance in the bottom-up and integrated models.

6.2. ELCA of power generation technology

The LCA's of the oil-fired steam turbine and the gas-fired combined cycle plant discussed in Sections 4.2 and 4.3 are extended to include an exergy analysis. The exergies of fuel oil and natural gas were calculated using the β value of 1.04 and 1.07, respectively (Szargut et al., 1988). Figure 6.1 shows the energy and exergy flows of the steam turbine plant. For the oil-fired steam turbine plant, the life cycle energy and exergy efficiencies are 30.8 % and 28.5 %, respectively. These values are 41.6 % and 40 %, respectively for the gas-fired combined cycle plant. In the study by Lombardi (2001), life cycle exergy efficiency of a gas turbine plant with CO₂ chemical absorption system was 33% while its classical energy efficiency was 45 %. The system boundary of the classical efficiency calculation is not defined but it is likely to be the conventional operational phase efficiency. In such a case, its life cycle energy efficiency will be much lower than the classical efficiency when the upstream processes of gas and CO₂ chemical absorption systems are included in the system boundary.

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Fig. 6.1. Life cycle energy - exergy flow of oil-fired steam turbine plant

From the referred case studies, it can be observed that the difference between the life cycle energy and exergy efficiencies is about 6 % for fossil based power generation technologies. This could be due to the difference between the energy and exergy values. The difference between energy and exergy efficiency resembled the efficiency calculation using higher and lower heating values of fuel. Therefore, it is concluded that performing ELCA based on black box type analysis across the life cycle

boundary do not provide any additional information compared to a LCA. However, ELCA can be useful if the exergy analysis is performed at a sub-system level.

6.3. ELCA in bottom-up approach

For a hypothetical end energy demand of hot water at 80°C, four sources of fuel were chosen and their energy and exergy flows are analysed. The fuel source and technology used are (i) fuel oil-fired boiler with an efficiency of 65 %, (ii) electric boiler with an efficiency of 95 % (iii) natural gas-fired boiler with an efficiency of 75 %, and (iv) solar thermal collector with an efficiency of 70 %. It was assumed that 65 % of electricity was generated from the gas-fired combined cycle plant with an efficiency of 55 % while the rest was from the oil-fired steam turbine plant with an efficiency of 33 %.

For the life cycle energy and exergy calculations, only the upstream processes of fuel production were included. Energy use for the conversion system, i.e. boiler, was ignored for simplification and their insignificant magnitudes (Lombardi, 2001). The temperature of cold water was taken as 25°C. Exergies of cold and hot water were estimated from their physical and chemical exergies (Szargut et al., 1988). A reference temperature of 30°C and a relative humidity of 65 % were used. The exergies of natural gas, fuel oil and solar radiation were estimated using a β value of 1.04, 1.07 and 0.93, respectively (Szargut et al., 1988). The conventional (operational phase) energy and exergy efficiencies and the life cycle energy and exergy efficiencies were calculated and presented in Table 6.1. The energy and exergy flows are shown in Figure 6.2.

It can be seen from Table 6.1 that electricity is the best choice of fuel for the hot water application based on the energy or exergy efficiencies. However, it became the

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last choice based on the life cycle energy or exergy efficiencies. Selecting based on the conventional operational phase efficiency would be flawed. Therefore, LCA/ELCA are important in the bottom-up approach.

Fig. 6.2. Energy and exergy flow in end-use applications

Table 6.1. Life cycle energy and exergy efficiencies in bottom-up approach

Fuel choice	Energy efficiency	Life cycle energy efficiency	Exergy efficiency	Life cycle exergy efficiency
Fuel oil	65 %	59.8 %	4.58 %	4.21 %
Natural gas	75 %	69.4 %	5.44 %	5.03 %
Electricity	95 %	39.1 %	7.17 %	2.80 %
Solar radiation	70 %	70.0 %	5.66 %	5.66 %

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To prioritise fuel options, both the life cycle energy and exergy efficiencies give the same order of preferences (see Table 6.1). Thus, the life cycle based (energy) analysis would be adequate just to prioritise energy sources. However, it does not mean that the life cycle exergy analysis is redundant. The life cycle exergy efficiency indicates the degree of resource utilisation. For example, in case of fuel oil used for hot water, the life cycle energy efficiency is 59.8 % whereas the exergy efficiency is 4.2 %. It can be interpreted that though 59.8 % of the input energy of fuel oil is utilised only 4.2 % of its quality, i.e. exergy, is utilised. This is because hot water is low grade (exergy) while the fuel oil is a high grade (exergy) energy source. In other words, fuel oil could be more effectively used for other applications such as electricity production wherein 31 % of its exergy can be utilised (see Figure 6.1). Therefore, an alternative low-grade energy source should be sought out for the hot water application.

It can be seen that the difference between the energy and exergy efficiency is large in energy consuming technologies whereas it is very small in power generation technologies (see Section 6.2). Therefore, ELCA is more useful in the bottom-up approach than in the top-down approach.

6.4. ELCA in integrated approach

The exergy destruction is high at the demand side (in electricity consumption) than the supply side. In the demand side, high exergy input carrier is converted to a low exergy output whereas in the supply side, e.g. power generation, high exergy input is converted to a high exergy output. Therefore, it could be easily concluded that high-exergy carriers should not be used for a low-exergy application. However, almost all end use services are low exergy applications and it is inevitable to use the high exergy carrier for some applications. For example, use of electricity for lighting is unavoidable though it is a high exergy to low exergy use. Nonetheless, there are many other end-

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use applications where exergy destruction can be minimised by seeking out alternative low exergy carriers. For example, the use of electricity (high exergy) for heating can be avoided by using waste heat (low exergy) from power plant. But, it is not always practical and would require strategic planning to synchronise demand and supply. In such a case, the integrated approach can play a significant role, which is illustrated with an example.

Let us consider an energy demand of electricity (high exergy) and hot water (low exergy) at various temperatures as shown in Table 6.2. Three supply options are studied to meet the demand (see Table 6.3). In the first two supply options (a top-down approach), high exergy carriers (electricity and natural gas) are used for low exergy hot water demand. The third option is an integrated approach, wherein waste heat (low exergy) is used for hot water application. The life cycle energy and exergy efficiencies of the three options are presented in Table 6.3. It can be seen that the life cycle energy/exergy efficiency is significantly increased in the integrated approach. Therefore, ELCA can be used as a tool for selecting alternative energy sources. It can also be used for pricing of energy services to promote energy efficiency at demand side (see Section 8.3.4).

Table 6.2. Energy and exergy demand of end use application

Energy demand	Quantity	Units	Energy (kWh)	Exergy (kWh)
Electricity	165	kWh	165	165
Hot-water at 90°C	500	Litres	38	3.44
Hot-water at 70°C	800	Litres	42	2.17
Hot-water at 50°C	1500	Litres	44	1.35
Total			289	171.96

Table 6.3. Energy supply scenario in top-down and integrated approaches

Energy supply options to meet the energy demand shown in Table 6.2		Life cycle* energy efficiency	Life cycle* exergy efficiency
1	Electricity is from gas-fired combined cycle power plant with an efficiency of 55 % Hot water is from electrical boiler with an efficiency of 90 % (This electricity is also produced from the gas-fired combined cycle plant).	48.57 %	27.88 %
2	Electricity is from gas-fired combined cycle power plant with an efficiency of 55 %. Hot water is from gas-fired boiler with an efficiency of 75 %.	57.42 %	32.96 %
3	Cogeneration: Electricity is from gas-fired combined cycle power plant with an efficiency of 55 %. Hot water from waste heat recovery boiler	88.83 %	50.99 %

* Only the upstream process of natural gas is included. Energy use for production of energy conversion equipments are ignored.

6.5. Uncertainties in exergy analysis

Exergy is equivalent to shaft work or electrical energy (Szargut et al., 1988). Shaft work and electrical work are considered to have the same exergy values. However, in conversion of electrical to shaft power or vice versa some exergy destruction is unavoidable. Therefore, in exergy analyse of systems, these should be differentiated in order to quantify the *avoidable* exergy destruction.

Over 45 % of exergy destruction occurs in the combustion where chemical exergy of fuel is converted to physical/thermal exergy (Taniguchi, 2005). Only when the combustion temperature is infinity will the exergy of combustion product be equal to the exergy of input fuel. However, the combustion temperature is controlled due to limitations of furnace brick and turbine materials. Thus, the destruction of exergy in combustion is unavoidable. Therefore, in an exergy analysis, the ‘avoidable’ and ‘unavoidable’ exergy destructions should be differentiated thereby minimising

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avoidable exergy. However, in a conventional exergy analysis, these are not addressed. For example, when a process uses fuel oil and electricity, the total exergy inflow is accounted as the sum of the exergies of electricity and fuel oil. This methodology fails to pinpoint which exergy stream (oil or electricity) has more avoidable exergy destruction. Fuel oil could have less 'avoidable' exergy destruction (due to combustion) than electricity. Therefore, the total exergy destruction does not reveal the details of avoidable exergy destructions.

6.6. Summary

Exergy is used to evaluate the energy systems in the top-down and bottom-up models. ELCA reveals that exergy analysis is useful in high exergy to low exergy conversion/application than in high exergy to high exergy conversion (fuel oil or natural gas to electricity). The conversion of high exergy to low exergy is more relevant to demand side electricity use. Therefore, in the bottom-up and integrated approaches, ELCA is more useful especially to seek alternative sources of energy for end use applications/services. Therefore, it can also be used as a tool for pricing of energy service in order to promote energy efficiency at demand side. An example on of an application of ELCA in the context of pricing is described in Section 8.3.4. In the top-down approach, insights from the ELCA are not significant compared to a LCA.

7. Power Generation Scenarios for Singapore

7.1. Introduction

Singapore is a small country (697 km² in area) with a population of 4.18 million (Singapore Department of Statistics, 2004). It is one of the most industrialised and urbanised economies in South-East Asia. In 2003, the country's gross domestic product was S\$ 159 billions (Singapore Department of Statistics, 2004). Power supply is an important sub-system in the national economy and its market transaction is about S\$ 3.5 billion (Dawson, 2004).

Singapore is heavily reliant on oil and natural gas and almost 100 % of its fuel needs are imported. There is no published data on Singapore's energy consumption from the Singapore authorities although the electricity consumption data are published by the Singapore Power, national utility company, and Energy Market Authority (EMA). Energy data published by institutions such as EIA, World Bank, British Petroleum, ADB, and APEC are not consistent. For example, the primary supply or commercial energy use data for the year 1994 was 12.31 million tonnes of oil equivalent (toe) in APEC (2002), 24.76 million toe in World Bank (2001), 19.1 in UN (1997), 28.1 in British Petroleum (2001), 50.89 million toe (imports minus exports) in ADB (2001) and 10.73 million toe in Ministry of the Environment (2000). The data from the Ministry of the Environment (2000) is the only known published data from a government agency. However, it is available only for the year 1994. In order to give an overview of Singapore's energy use pattern, the data published by the Asia Pacific Economic Research Cooperation (APEREC) is presented here.

In 2001, the primary energy consumption was about 22 million toe, in which oil accounted for 80 % and natural gas accounted for 20 % (APEREC, 2003). Oil is used for

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Singapore can be shielded from any commitments using the provisions under Article 4.8 of the UNFCCC. Article 4.8 states that “the Parties shall give full consideration to meet the specific needs and concerns of developing country Parties arising from the adverse effects of climate change and/or the impact of the implementation of response measures”. Some of the sub-clauses are of specific relevance to Singapore, namely, 4.8(a) “Small island countries and 4.8(h) Countries whose economies are highly dependent on income generated from the production, processing and export, and/or on consumption of the fossil fuels and associated energy-intensive products” (UNFCCC, 1992).

Table 7.1. Energy use and CO₂ emission: Singapore versus Annex-I countries

Country	1998	1999	2000
Per capita energy use (<i>toe</i>)			
Germany	4.255	4.161	4.178
Japan	4.044	4.071	4.132
Singapore	5.596	5.675	6.120
United Kingdom	3.930	3.946	3.926
United States	7.930	8.066	8.163
Per capita electric power consumption (<i>kWh</i>)			
Germany	5,681	5,690	5,963
Japan	7,287	7,447	7,406
Singapore	6,448	6,641	6,948
United Kingdom	5,387	5,495	5,597
United States	11,925	12,092	12,399
Per capita CO ₂ emissions (<i>tonnes</i>)			
Germany	10.06	9.64	9.55
Japan	8.96	9.12	9.34
Singapore	13.95	14.4	14.7
United Kingdom	9.25	9.15	9.64
United States	19.98	19.76	19.85

Source: World Bank, 2004

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This research explores the possibilities of GHG mitigation in Singapore's power sector, which accounts for a major share of the country's total GHG emission. This chapter describes power generation scenarios from the top-down and integrated approaches. The power generation scenario refers to a set of illustrative power generation mix to meet the forecasted power demand. After this introductory section, an overview of the Singapore's power sector is presented. In Section 7.4, a number of power generation mix scenarios are developed for a period of 2004 - 2013 using the top-down model. Their primary energy use, GHG emissions and costs are estimated. Section 7.5 describes two bottom-up measures using the DCS and cogen and their integrated power generation scenarios. In Section 7.6, results of both the top-down and bottom-up approaches are discussed.

7.2. Singapore's power sector

7.2.1. Electricity generation and consumption

In 2003, total electricity consumption was about 32 TWh_e (EMA, 2004). Figure 7.2 shows the historical electricity consumption during 1983-2003. As can be seen, electricity consumption has been increasing although its growth rates are decreasing. In a 10-year time horizon, the annual average electricity consumption growth rate has decreased from 8.4 % (1983-1993) to 6.5 % (1993-2003). In a 5-year time horizon, its growth rate decreases from 8.7 % (1993-1998) to 4.2 % (1998-2003). This slowdown in growth may indicate that Singapore's power consumption is nearing its saturation level. The electricity demand is projected to grow at an annual rate of 3 to 5 % from 2003 through 2013 (APERC, 2003).

Figure 7.3 shows the sector-wise distribution of electricity consumption in three major sectors. In 2003, about 43 % of the electricity was consumed in manufacturing

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sector and the commercial and residential sectors accounted for 37 % and 20 %, respectively (EMA, 2004c). This trend is almost same in the last decade.

Source: ADB, 2001; EMA, 2004c

Fig. 7.2. Historical electricity consumption in Singapore

Source: EMA, 2004c

Fig. 7.3. Sector wise electricity consumption in Singapore

In 2003, peak power demand was 4945 MW and it grew annually at a rate of 3.6 % from 1999 to 2003 (EMA, 2004). Figure 7.4 shows the trend in the peak power demand. There is no seasonal variation in power demand although it varies between the weekdays and weekends/public holidays. Figure 7.5 shows a typical load profile. On weekdays, the demand increases at a steep rate from 8:00 hrs and reaches a peak at about 11:00 hrs, as most offices and industries begin their operations during this period.

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This adds about 1300 MW or about 30 % of peak electrical demand on the system. Air conditioners are one of the major power demands during the peak hours.

Source: Singapore Power, 2000; EMA, 2004

Fig. 7.4. Peak power demand and installed generation capacities

Source: EMA, 2004a

Fig. 7.5. Power demand profile of Singapore

In 2003, Singapore had 8919 MW installed power generating capacity. The installed power plant consists of 53 % steam turbine plants and 30 % combined cycle plants (see Figure 7.6) (EMA, 2003a). However, electricity generation from the

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combined cycle plants accounted for 61 % (EMA, 2004). Installed capacity of the combined cycle plants is likely to increase.²¹

Source: EMA, 2003a

Fig. 7.6. Installed capacity by plant type in 2003

Singapore has about 22,544 km underground cable network for electricity T&D (PowerGrid, 2004). The T&D losses in 2001 was 4.16 % (World Bank, 2004).

7.2.2. Fuel consumption in power sector

Until 1992, oil was the only fuel used for the power generation. To diversify its energy source, Singapore began importing natural gas from Malaysia and started using natural gas for power generation in 1992. In 1993, natural gas accounted for about 16 % of the total power generation (Singapore Power, 1997). In 2001, natural gas supplies via submarine pipelines from Indonesia’s West Natuna gas fields commenced under a 22-year contract with SembCorp (SembUtilities, 2004). The use of natural gas for power generation has grown from 28 % in 2001 to 44 % in 2002 (EMA, 2004). Singapore Power contracted with Pertamina to buy gas from gas fields in South Sumatra over a 20-year period and gas started flowing in 2003 (PowerGas, 2004). In

²¹ About 1094 MW combined cycle plants are under construction (734 MW in TuasPower (2004) and 360 MW in SenokoPower (Yu, 2004)).

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2003, 60.8 % of the electricity was generated from gas-fired combined cycle plant, 34.6 % from fuel oil-fired steam turbine plant and the rest was from other fuels (refuse incineration, diesel, synthesis gas and Orimulsion oil) (EMA, 2004).

Figure 7.7 shows the trend in fuel consumption of power sector. The fuel consumption data from 1993 to 1997 are obtained from Singapore Power (1997).²² From 1998 through 2003, they were estimated from the electricity generation data, power generation mix (EMA, 2003; 2004) and net plant efficiency²³. From Figure 7.7, it can be seen that the fuel consumption increased until 2000 and then declined despite the continued increase in power consumption. This can be attributed to increased use of natural gas and its efficient use in combined cycle plants. The relatively higher diesel consumption in 2002 might be due to interruption of gas supply that also caused a blackout (EMA, 2002).

Fig. 7.7. Fuel consumption in power sector

²² In 1994, primary energy consumption of 4.58 million toe (or 186,501 TJ) for the Singapore power sector was reported by the Ministry of the Environment, Singapore (2000), which is about 6 % higher than the reported by Singapore Power (1997). Differences in the figures were also seen in the fuel mix.

²³ Net efficiencies of 50.9 to 52 % for gas-fired combined cycle plant, 36 % for oil-fired steam turbine plant and 38 % for diesel-fired were used (Yu, 2004) (also see Section 7.4.1c).

7.2.3. Clean and renewable sources

Due to Singapore's geographical area, renewable energy sources for the power generation are limited. There are no hydro and geothermal energy sources. Neither is there enough land to cultivate biomass as an energy source. It also cannot tap wave energy due to the relatively calm seas and shortage of sea space. Wind energy has limited potential due to the relatively low wind speeds and lack of land to establish wind farms. Nuclear energy cannot be used due to geo-political and safety concerns (Ministry of the Environment, 2000). The only known source of renewable energy is solar radiation. The country receives an annual solar radiation of 1635 kWh/m² (Meteorological Service Singapore, 1997). However, large-scale power generation from solar PV systems is limited because of constraints in space. Thus, only small-scale solar PV systems can be considered for DG. As a demonstration project, a 8.9 kW_p grid connected solar PV system has been operating since 2002. There are also few other solar PV installations with battery storage (Jiang, 2004). A test-bedding project is currently underway in a multi-storey car park where the lights are powered by fuel cells using hydrogen produced by on-board reforming of natural gas (Balakrishnan, 2004).

7.2.4. CO₂ emissions

The CO₂ emission from the power sector was estimated from the fuel consumption (see Section 7.2.2) and specific CO₂ emission factors (IPCC, 1996c). In 2003, the total CO₂ emission is estimated to be about 17 million tonnes. Singapore's average CO₂ emission factor of electricity consumption is about 530 g-CO₂/kWh while the life cycle GHG emission factor is 610 g-CO₂/kWh (see Section 7.3). Figure 7.8 shows the CO₂ emissions and electricity consumption during 1993-2003. The CO₂ emission follows the increasing trend of electricity consumption. After 2001, CO₂

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emission has been decreasing due to increased use of gas for power generation. As can be seen in Figure 7.8, CO₂ emission in 2003 was lower than in 1998.

Fig. 7.8. CO₂ emissions from Singapore’s power sector

7.2.5. Electricity market

Power supply was initially provided by the state-owned Public Utilities Board (PUB). In 1995, PUB was corporatised. In 1998, the Singapore Electricity Pool (SEP) was introduced to operate a wholesale electricity market, which allowed trading of electricity between generator and retail companies. In 2001, a national electricity regulating authority, the Energy Market Authority (EMA) was formed to regulate the electricity industries. In 2002, a new independent market operator, Energy Market Company (EMC) was established and EMA becomes the industry regulator. In 2003, the wholesale electricity market (National Electricity Market of Singapore - NEMS) began its operations. A detailed structure of Singapore’s deregulated market is described by Chang and Tay (2005). Currently five active generating companies are in the market, including the National Environmental Agency, which produces electricity from waste incineration. There are five retailers, who buy electricity from the wholesale electricity market and sell it to the contestable consumers. Singapore Power

supplies electricity to the non-contestable consumers at regulated tariffs. PowerGrid is responsible for T&D (EMA, 2003; EMC, 2003).

7.3. Life cycle energy, emission and costs of power sector

Conventionally, the national GHG emission inventories are estimated based on the emission (often CO₂) from within the national territory (as estimated in Section 7.2.4). Therefore, emissions that occur outside the territory are not accounted in the national emission inventories. Since this study uses LCA, GHG emissions need not necessarily occur within the territory. The GHG emissions scenarios established in this study are based on the GWP. To avoid misconceptions, CO₂ emissions and GWP are estimated and referred as *local CO₂ emission* and *global GHG emission*.

In the local CO₂ emission (LSXx)²⁴, the CO₂ emissions occur within Singapore is estimated. They are mainly from the combustion of fuels used in the operational phase and do not account for the upstream processes of fuels. In a case of power generation from renewable sources, e.g. solar PV, no CO₂ emissions are accounted.

In the global GHG emission (GSXx), the GHG emissions are estimated based on the life cycle GWP and presented in CO₂-equivalents. The life cycle GWP are obviously higher than the operational phase CO₂ emission. Therefore, the global GHG emissions are higher than the local CO₂ emission. The differences are due to the consideration of hidden emissions.

Figure 7.9 shows the local CO₂ and global GHG emissions of Singapore's power sector during 1993-2003. The global GHG emission in 2003 was about 19.54 million tonnes of CO₂ equivalent, which is 15 % higher than the local CO₂ emission of 16.97 million tonnes.

²⁴ In acronyms LSXx and GSXx, Xx represents the scenario numbers. For example, LS5b is the local CO₂ emissions in scenario 5b (see Section 7.4.6).

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Fig. 7.9. Local CO₂ and global GHG emission from Singapore power sector

Similarly, the life cycle primary energy demand of the power sector is also different from fuel demand. In the primary energy demand, energy used for the upstream processes and transportations of fuel are included as per the LCA boundary. For example, the primary energy demand for the Singapore's power sector in 2003 was about 6.77 million toe compared to the fuel demand of 6.24 million toe.

Though all the primary energy demand and global GHG emission do not occur within Singapore, they are the *real* fossil energy use and emission caused by the power sector. Therefore, appraisal of various power generation mix scenarios (see Section 7.4) based on their global GHG emissions/primary energy use would facilitate identifying the more sustainable power generation from the global perspectives.

The total life cycle cost involved in the power supply is also estimated based on the unit cost of electricity generation from individual sources. For example, in 2003, the life cycle cost of the power supply is about S\$ 2.68 billion excluding the T&D cost (see Section 7.4.1 for assumptions). The total life cycle costs are in present values - as the inflations or escalations of fuel price are included in the LCCA of each of the power generation sources (see LCCA in Chapters 4 and 5). Thus, the changes in the total life

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cycle cost can be used as the indicators to justify the cost effectiveness of the selected power generation mix.

7.4. Top-down approach of power generation planning

In order to identify a sustainable power generation mix, few power generation mix scenarios are constructed under the top-down approach for a period of 2004 - 2013. The top-down approach explores all possible power generation sources to meet forecasted power demand. Singapore's electricity demand is forecasted to grow at 3 to 5 % per year from 2003 through 2013 (APERC, 2003). For this study, an annual average growth rate of 4 % is used during 2004-2013. For the forecasted power demand, numerous power generation mix scenarios can be constructed using this model. Eleven plausible power generation mix scenarios are constructed, viz. S1a to S6. The assumptions and examples used in the scenarios serve only to validate the framework developed in this research. They do not predict what the future will be or even what it should be like other than to explore the possibilities.

For each of the power generation mix scenarios, their annual life cycle primary energy use, GHG emission and costs are estimated. Their year-to-year growth rates and the overall annual average growth rate from the base year 2003 are calculated. The overall growth rates are used as indicators to evaluate each of the power generation scenarios. This also enables the comparison between the power generations mix in the top-down model and integrated framework (see Section 7.6). This section describes the various power generation scenarios, their underlying assumptions and the results of the scenario studies.

7.4.1. Assumptions

In scenario studies, it is important to use rational assumptions. For this study, the following assumptions are made to validate the model. The model has provisions to

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change any of the assumptions to see the outputs. The assumptions associated with the scenarios studies are: -

- a) Electricity generation from the waste-incineration plants would be about 950 GWh_e during the selected time horizon based on the current²⁵ generation of 970 GWh_e (Cheong, 2004). Energy use, emissions and cost of electricity generation from the incineration plants are not accounted.
- b) T&D loss of 4 % would be same during the selected time horizon. For DG such as solar PV and fuel cells, the T&D loss is zero.
- c) For estimation of global GHG emissions and primary energy use, the correlations established in Chapter 4 [see Equations (4.1) to (4.6)] are used with an annual net efficiency. It is assumed that the annual net efficiency has taken into account the efficiency fluctuation with load factor, energy consumed in start-up, part-load operations, etc. For this study, the net efficiency of 36 % and 33 % is used for the oil-fired and Orimulsion-fired steam turbine plants, respectively. For gas-fired combined cycle plant, the net efficiency of 52 % during 2004-2005, 53 % during 2006-2008 and 55 % from 2009 onwards are used. For SOFC-gas turbine hybrid system (SOFC-GT), 60 % electrical efficiency is used (Chan et al., 2003). The fuel cell system is considered as DG. For these operating parameters, the life cycle primary energy use and GHG emissions are shown in Table 7.2.
- d) The life cycle cost of power sector during the selected time horizon is estimated based on the above referred efficiencies at an annual load factor of 80 % and the following fuel prices.

²⁵ Due to improved recycling programmes, waste generation has been declining (Cheong, 2004).

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- i. Based on the Singapore Fuel Oil Price Index, high sulphur fuel oil (HSFO) price of 2004 was about S\$ 305 per tonne and the forwarded price for 2005 is about S\$ 346 per tonne. In this scenario study, current market HSFO price of S\$ 325 per tonne is used (10X Group, 2004).
- ii. In Singapore, the gas price is pegged to HSFO price. The gas from Malaysia is based on 107 % of the HSFO, while that from Indonesia costs 115 % of the HSFO price (The Business Times, 2004). For this study, a weighted average of 113 % of fuel oil prices is used as 80 % of the gas is imported from Indonesia. Therefore, a gas price of S\$ 8.7 per MMBTU is used.
- iii. Orimulsion price of S\$ 125 per tonne (about 38 % of HSFO price) (see the Section 4.6.3).
- iv. Solar PV systems to be installed during 2006 - 2009 is accounted based a capital cost of 10.5 S\$/W_p by considering its as a large-scale installation (Solarbuzz, 2005). Since, it is commonly expected that the price of PV modules and inverters would come down, solar PV systems installed from 2009 are accounted with a capital cost of 9.5 S\$/W_p.
- v. For PEMFC, an average fuel cell cost of S\$ 7600 per kW is used (DoE, 2004a). Since SOFC-GT is not yet commercialised, its cost is not available. DoE (2004) has a price target of US\$ 400 per kW. However, for this study, the average fuel cell cost of S\$ 7600 is used. Thus, the difference between cost of electricity from PEMFC and SOFC-GT is due to their efficiency variations (see Table 7.2).
- vi. To normalise the electricity generation from central power plants and DG, energy losses in T&D and the cost involved in establishment of T&D network

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are accounted in the centralised power generation technologies. In Singapore, low-tension transmission cost is 5.6 ¢/kWh (Singapore Power, 2004). These values are added to the centralised power generation technologies although it could be lower for high-tension (HT). Table 7.2 summarises the LCC of electricity generation from the selected power generation technologies.

Table 7.2. Life cycle energy, GWP and cost inventory of electricity generation

Power generation systems	Net (LHV) efficiency	Life cycle primary energy use (MJ/kWh _e)	Life cycle GWP (g-CO ₂ /kWh _e)	LCC (¢/kWh _e)
<i>Centralised power generation systems</i>				
Oil-fired steam turbine	36 %	11.32 ^a	889 ^a	16.48 ^{b, c}
Gas-fired combined cycle	50 %	8.10 ^a	493 ^a	13.58 ^{b, d}
Orimulsion-fired steam turbine	33 %	12.57 ^a	990 ^a	13.61 ^{b, e}
<i>Distributed power generation systems</i>				
Solar PV (mono-crystalline)	7.9 %	2.94	219	80.23 ^f
Gas based PEMFC	26 %	14.93	899	28.21 ^{d, g}
SOFC-GT	60 %	6.50	392	21.03 ^{d, h}

^a 4 % T&D losses included

^b 5.6 ¢/kWh included for T&D network

^c Fuel oil price of S\$ 325 per tonne

^d Natural gas price of S\$ 8.7 per MMBTU

^e Orimulsion price of S\$ 125 per tonne

^f Solar PV system price of S\$ 10,500 per kW_p

^g PEMFC system price of S\$ 7600 per kW

^h SOFC-GT price of S\$ 7600 per kW [see note in Section 7.4.1.d(v)].

7.4.2. Scenario S1: Fuel switching to gas

As can be seen in Table 7.2, the gas-fired combined cycle plant is the cost effective source of power generation and its GWP is also relatively low. Hence, a shift towards the natural gas based combined cycle plant would be a good choice for Singapore. Power generation from gas has reached to 70 % in September 2004 (Dawson, 2004). In scenario S1, the power generation would steadily switch over to 100 % natural gas. In S1a, the percentage of gas is increased by 5-percentage points

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per year while it is 10-percentage points in S1b. For S1 scenario, it is assumed that gas availability would not be a constraint to meet the power sector's gas demand. In S1a, the percentage of gas in the total power generation mix would begin with 75 % in 2005 and reach 95 % by 2009. The rest of the power would be generated from fuel oil. After 2010, natural gas would be the only fuel source for power generation other than waste heat from incineration plants (see Section 7.4.1.a).

Figures 7.10 and 7.11 show the power generation mix and fuel demand for the S1a scenario. By 2010, the gas demand would be about 6.7 million toe, which is about 85 % of the total gas imported or 104 % of the gas imported from Indonesia alone. In 2013, the total gas demand for the power sector would be about 7.5 million toe. To meet this gas demand, Singapore should seek for additional gas suppliers.

In S1b, power generation from natural gas would reach to 95 % by 2007. After 2008, natural gas would be the only source of fuel for power generation (see Figure 7.12). The gas demand in 2007 would be about 6.2 million toe. After 2010, the gas demand would be the same as in scenario S1a.

Figure 7.14 shows the global GHG (GS1) and local CO₂ (LS1) emission for scenario S1. In S1a, GHG emissions would decrease at 1.14 % between 2004 and 2009. This negative growth is the result of low specific emissions from gas-fired plants, which offsets the high specific emissions from fuel oil-fired plant. At the same time, the emission reduction from this fuel switching is huge enough to offset the emissions of additional power generation in each year. When power generation switches over completely to gas in 2010, then the emission would increase at an annual rate of about 4 % during 2011-2013. As can be seen in Figure 7.14, the GHG emission would bounce back to today's level by 2011. During the selected time horizon of 2004-

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Fig. 7.10. Power generation mix in Scenario S1a

Fig. 7.11. Fuel demand in Scenario S1a

Fig. 7.12. Power generation mix in Scenario S1b

Fig. 7.13. Fuel demand in Scenario S1b

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2013, the cumulative GHG emissions would be about 192 million tonnes which works out to an annual emission reduction of 0.37 % from the base year 2003.

In S1b, GHG emission would decrease at an annual average of 3.6 % until 2007. GHG emission in 2007 would be equal to the emission in 1996 (see Figure 7.14). However, from 2008 through 2013, GHG emissions would increase at an annual average rate of 3.5 %. The difference between GHG emissions in S1a and S1b is only during the earlier periods. In S1b, it decreases and then increases at a steeper rate thereby resulting in a higher overall GHG emission reduction in S1b. Though the electricity demand is increased at 4 % during the selected time horizon, the emission would decline at an annual rate of 1.1 % in the S1b.

Fig. 7.14. Emissions in Scenario S1

As far as the primary energy use is concerned, it would increase at a rate of 1.7 % and 1.3 % in S1a and S1b, respectively (see Figure 7.38). Their cumulative primary energy use during the selected time horizon would be about 72.8 and 71.6 million toe whereas their fuel demands would be about 67.3 and 66.1 million toe, respectively (see Table 7.3).

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Under scenario S1a, the total life cycle costs incurred in power supply would increase at an annual rate of about 3.1 % during 2004-2013 and it would be 2.9 % in S1b. These annual increases are lower than the electricity demand growth rate of 4 %. The lower cost is due to the cheaper cost of electricity generation from gas-fired combined cycle plants.

7.4.3. Scenario S2: Switching over to gas with supply limitations

As far as the current natural gas availability is concerned, Singapore imports natural gas of about 825 million SCF per day (about 7.8 million toe per year) from Malaysia and Indonesia via three pipelines (EMA, 2004). The contract for gas import from Malaysia is scheduled to expire in 2007. For the S1 scenarios, it is assumed that the gas contract of Malaysia would be renewed after 2007. At the same time, alternative sources of natural gas such as LNG, would be made available.

If the gas supply from Malaysia or alternative sources of gas supply is not available after 2007, then the gas supply would not be adequate to meet the power sector's demand in the scenario S1. Thus, an alternative power generation mix scenario S2 is developed. As of today, gas imports from Indonesia account for about 82 % of the total gas imported in Singapore or 6.43 million toe. For scenarios S2, the power generation from gas is limited to a maximum gas availability of 6 million toe. When the gas demand reaches its limit of 6 million toe, the rest of the power would be generated from fuel oil-fired steam turbine plants or Orimulsion fuel (see scenario S4 in Section 7.4.5). The rate of fuel switching in S2 is the same as in S1.

The power generation mix and fuel demand of the scenario S2a are shown in Figures 7.15 and 7.16. It can be seen that firstly the power generation from fuel oil declines and then increases from 2009 as the natural gas demand reaches its limit of 6 million toe. During 2004-2009, the difference between the power generation mix in

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Fig. 7.15. Power generation mix in Scenario S2a

Fig. 7.16. Fuel mix in Scenario S2a

Fig. 7.17. Power generation mix in Scenario S2b

Fig. 7.18. Fuel mix in Scenario S2b

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S2a and S2b are similar to that of S1a and S1b. After 2009, both the power generation mix and fuel mix are the same in the S2a and S2b (see Figures 7.17 and 7.18).

The emissions of S2 are presented in Figure 7.19. During 2004 - 2009, the GHG emissions in S2a would decline at an annual average rate of 1.0 %. It would then increase at a rate of 6.2 % from 2009 through 2013 due to more power generation from fuel oil as the gas use is limited to 6 million toe. The cumulative GHG emissions during the selected time horizon would be about 205 million tonnes, which is about 7 % higher than in S1a. Thus, the overall emission would increase at a rate of 1.1 % from the base year 2003.

Fig. 7.19. Emissions in Scenario S2

In S2b, GHG emission would decrease at a steeper rate of 3 % from 2004 to 2007 and then increase at a rate of 6.4 %. By the year 2009, GHG emissions would reach today's level and it would bounce back to the 2000 level in 2012. The cumulative GHG emission of S2b would be about 200 million tonnes and the overall emission would grow at 0.6 % during the selected time horizon.

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The cumulative primary energy use of S2a would be about 75.7 million toe compared to 69.9 million toe of fuel demand. In S2b, it would be about 74.7 and 69 million toe, respectively. The primary energy use would increase at 2.6 % and 2.3 % in S2a and S2b, respectively during 2004-2013.

The life cycle costs of S2a and S2b would increase at an annual rate of 3.6 % and 3.4 %, respectively. The higher costs in the S2a are due to greater use of fuel oil during 2006-2008 and its higher cost of generation.

7.4.4. Scenario S3: Gas and fuel oil mix

For the power generation scenarios in S1, fuel security poses a big challenge due to reliance on a single fuel, i.e. natural gas. Recently, the country experienced two major blackouts caused by an interruption in the gas supply pipeline. Fortunately, the blackout was short-lived and power supply was restored by switching over to fuel oil. The interruption in the gas supply was due to technical faults in the gas supply pipeline valves. In 2002, the emergency shutdown valves were activated and disrupted the natural gas supply (EMA, 2002) while in 2004, it was due to failure of a pressure regulating valve (EMA, 2004b). Reoccurrence of such an interruption may be more critical, especially if it could be due to any accident or political vulnerability. Risks of fuel security cannot be avoided in Singapore, as almost 100 % of its fuel needs are imported. However, reliance on a single source of natural gas supply would pose additional risks to the reliability of entire power supply. Unlike fuel oil that can be stored in large volumes, an alternative supply of natural gas cannot be obtained within a short time because of the limitations in infrastructure. One option would be to diversify to liquefied natural gas (LNG). Singapore do have plans to build a LNG import terminal, thereby freeing itself from complete dependence on its neighbouring countries for its gas supply (Balakrishnan, 2004; EMA, 2005). LNG's scale of economy is still

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unclear although it is likely to be expensive (DRPL, 2004). Therefore, a shift to 100 % natural gas would not be the best choice even if natural gas is a cleaner and cheaper source of fuel for power generation.

The next fuel option for the power generation is fuel oil (or Orimulsion – see scenario S4 in Section 7.4.5) that has higher specific GHG emissions and cost (see Table 7.2). From fuel security perspective, availability of fuel oil is abundant considering that Singapore is a petrochemical hub. Sourcing an alternative oil supplier cannot be more vulnerable compared to natural gas supply. Therefore, it becomes necessary to achieve a balance between the use of natural gas and alternative sources of fuel for the power generation. In any case, it is impossible to be shielded from oil price shocks or political vulnerabilities.

For scenario S3, power generation from gas is limited to a maximum of 80 % and 90 % of the total power generation mix. The rest of the power generation is assumed to be from fuel oil. In S3a, natural gas is limited to a maximum of 80 % and a fuel switching rate of 5-percentage points per year (as in S1a) is considered. For S3b, natural gas is limited to 90 % and a fuel shift of 10-percentage points per year as in S1b. The power generation mix and fuel demand of scenario S3a and S3b are shown in Figures 7.20 to 7.23. In S3a, the gas demand would reach up to a maximum of 6.2 million toe by 2013 while it would be about 6.9 million toe in S3b. Therefore, under the scenarios of S3, today's level of gas import would be adequate to meet the power sector's gas demand.

In S3a, GHG emissions would decline at an average rate of 3 % per year during 2004-2006 and then it would increase from 19.1 million tonnes in 2006 to 24.7 million tonnes in 2013. The GHG emission would reach to the 2000 level by 2011. By the end of the selected time horizon, GHG emissions would be higher than the emissions in

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Fig. 7.20. Power generation mix in Scenario S3a

Fig. 7.21. Fuel mix in Scenario S3a

Fig. 7.22. Power generation mix in Scenario S3b

Fig. 7.23. Fuel mix in Scenario S3b

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Fig. 7.24. Emissions in Scenario S3

2000 which was the peak in the last decade (see Figure 7.24). The GHG emission of S3a would increase at a rate of about 1.8 %, which is the highest among all other scenarios (see Tables 7.3 and 7.4).

In S3b, GHG emission would decrease at 3.8 % from 2004 through 2006 and then increase at an annual rate of 3.7 %. The GHG emissions would reach today’s level by 2007. The overall emission would increase at 0.1 % per year from the base year 2003. The primary energy use and the life cycle costs of S3a would grow at an annual rate of 3 % and 3.9 %, respectively during the selected time horizon whereas they would be about 2 % and 3.3 %, respectively in S3b. Higher increases in the costs are caused by the fuel oil-based power generation.

7.4.5. Scenario S4: Use of Orimulsion fuel

PowerSeraya, one of the power companies in Singapore, would be using Orimulsion fuel from 2005. The Orimulsion based power generation can be considered as an alternative to S3, wherein fuel oil is used up to a minimum of 10 % for fuel security purpose. As far as the availability of Orimulsion fuel is concerned, it is also

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from a single supplier BITOR, Venezuela. For S4, Orimulsion fuel is considered in the power generation mix. The company converted three 250 MW fuel oil-fired steam turbines to fire Orimulsion fuel (PowerSeraya, 2004). For a 250 MW Orimulsion-fired plant, about 0.7 million tonnes of Orimulsion fuel would be required annually (at 33 % efficiency and 7200 hours operation). Based on press releases (Dow Jones Energy Services, 2003), PowerSeraya plans to buy 1.7 million tonnes of Orimulsion a year through a 10-year contract. Latin Petroleum (2004) stated that PowerSeraya would require about 0.5 million tonnes of Orimulsion in 2005 and about 1.0 - 1.2 million tonnes a year.

For scenario S4a, 0.5 million tonnes of Orimulsion fuel in 2005 and one million tonnes (0.67 million toe) in the subsequent years are assumed. The rest of the power generation is assumed to be from gas. Figures 7.25 and 7.26 show the generation and fuel mix of S4a. It can be seen that the power generation from Orimulsion fuel in the total power generation would be about 3.5 % in 2005 and 6.7 % in 2006. In subsequent years, it would decline to about 5 % in 2013. However, the quantity of Orimulsion fuel would remain unchanged at one million tonnes.

For the S4b scenario, 10 % of the power generation is assumed to be from Orimulsion fuel. In scenario S4b, Orimulsion fuel demand in 2006 would be about 1.5 million tonnes (one million toe), which is adequate to run two 250 MW steam turbines. In 2013, the total Orimulsion fuel demand would be about two million tonnes (1.3 million toe). Figures 7.27 and 7.28 show the power generation mix and fuel demand of S4b scenario.

The GHG emissions in S4a decrease until 2006 at an annual rate of 3.3 % due to increased use of natural gas. However, after 2007, the emissions increase at a rate of

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Fig. 7.25. Power generation mix in Scenario LS4a

Fig. 7.26. Fuel mix in Scenario LS4a

Fig. 7.27. Power generation mix in Scenario LS4b

Fig. 7.28. Fuel mix in Scenario LS4b

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3.2 % despite the share of natural gas being maintained at the same level. This is because of the higher specific emissions from the Orimulsion-fired plant. It can be seen in Figure 7.29 that the GHG emission reaches to today's level by 2010. The overall emission would increase at 0.1 % per year from the base year 2003. In S4b, it would increase at 1 %. In S4b, GHG emission in 2013 would reach to the emission level of 2000. If S4b is considered as an alternative to S3b, then the cumulative emission in S4b is 3.5 % higher than the S3b. However, its cost is 0.1% lower than the S3b.

Fig. 7.29. Emissions in Scenario S4

The primary energy use and cost would increase at a rate of 2 % and 3 %, respectively in S4a. In S4b, the cost would increase by 3.1 %. It can be seen that even if 10 % of power were to be generated from Orimulsion fuel, its cost would not increase very much from S1, a 100 % gas based power generation scenario. This is because of the cheaper cost of electricity generation from Orimulsion fuel.

7.4.6. Scenario S5: Solar PV

As far as the renewable energy source in Singapore is concerned, solar radiation is the only known source for power generation (see Section 7.2.3). As can be seen in

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Table 7.2, power generation from a solar PV system consumes less than one-fourth of the life cycle primary energy of the oil-fired plant or about 40 % of the gas-fired plant. Its GWP is also about one-fourth of the oil/ Orimulsion-fired plant and half of the gas-fired plants. Therefore, from either the fuel security or GHG emission perspective, solar PV is a good alternative. However, the cost of electricity generation from the solar PV system is about 5 to 7 times higher than the oil/Orimulsion/gas based power generation. Therefore, in the short-term, the solar PV module is not economically the best choice. However, solar PV based power generation can be shielded from oil price shocks. In late 2004, crude oil prices surged to a new high of US\$ 55 per barrel (The Straits Times, 2004) while the fuel oil price was about S\$ 370 per tonne (10X Group, 2004). Therefore, solar PV could be a good choice in the long run, especially in the light of GHG emission mitigation obligations and oil price shocks.

Scenario S5 analyses the power generation mix, if 1000 GWh_e of electricity were to be generated from solar PV by 2013, which is less than 2 % of the total electricity demand in 2013. Though there are constraints in space, rooftops of the public housings (HDB Blocks) can be effectively used for installation of solar PV systems and about 1000 GWh_e could be tapped annually²⁶. However, generating this quantity of electricity from a solar PV system would require an installed capacity of about 1000 MW_p, which represents a substantial capital investment of billions of dollars. It makes power generation scenario appear over optimistic.

For S5a, solar PV based power generation would begin with 40 GWh in 2006 with a year-to-year penetration of 60 %. There is no specific rationale to assume a 60 % penetration rate other than to achieve a target of 1000 GWh_e by 2013. The rest of the

²⁶ In Singapore, the total residential land area is about 73 km² (HDB, 2003). If 15 % of this area (rooftops) were to be used for installation of solar PV system with a net efficiency of 6 %, there would be a potential to generate about 1074 GWh_e annually.

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power generation would be from gas as in S1a. Figures 7.30 and 7.31 show the power generation mix and fuel demand of S5a.

For S5b scenario, in addition to achieving about 1000 GWh_e of electricity from solar PV by 2013, 10 % of the power would be from fuel oil. Thus, fuel oil form part of the power generation mix. The power generation mix and fuel demand of scenario S5b are shown in Figures 7.32 and 7.33.

Under scenario S5a, the emissions would decline at an annual rate of about 1.24 % during 2004-2009 (see Figure 3.34). This is mainly due to the switching of fuel oil to gas rather than solar PV based power generation. However, solar PV do contribute to some extent. If there is no solar PV based power generation, then the emission would decrease only at 1.14 %. The GHG emission in 2009 would be about 19.6 million tonnes, which is slightly lower than in 1998. After 2009, emission would increases at an annual average rate of 3.2 %. The cumulative GHG emissions of S5a would be about 191 million tonnes, which is the third lowest among all the scenarios. The overall emission would decline at 0.5 % during the selected time horizon compared to 4 % growth in electricity demand.

In S5b, GHG emission would decline at a rate of 0.7 % during 2004-2007. Then it would increase at 3.6 % during 2009 – 2013 (see Figure 3.34). The overall emission would increase at 0.7 % per year from the base year 2003. High specific emissions from fuel oil based power generation have masked the impact of solar PV based power generation.

As far as primary energy use is concerned, it would increase by 1.6 % and 2.3 % in S5a and S5b, respectively. The life cycle cost would also increase at 3.9 % and 4.2 % in S5a and S5b, respectively. The cost in S5b is the second highest among all the

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Fig. 7.30. Power generation mix in S5a

Fig. 7.31. Fuel demand in scenario S5a

Fig. 7.32. Power generation mix in S5b

Fig. 7.33. Fuel demand in scenario S5b

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Fig. 7.34. Emissions in Scenario S5

scenarios (see Tables 7.3 and 7.4) because of the extremely high costs of solar PV based power generation although it contributes for about 2 % of the total power generation by 2013.

7.4.7. Scenario S6: Fuel cells and solar PV

From the efficiency of PEMFC, it can be concluded that the fuel cell is not a good choice of power generation because of the high efficiency of a gas-fired combined cycle plant (>50 %). Fuel cell technologies are still at the initial stage of development. In long-run, the solid oxide fuel cell (SOFC) would emerge as a promising technology for power generation. For hybrid SOFC/gas turbine or SOFC/combined cycle systems, electrical conversion efficiencies are expected to be over 60 % (Chan et al., 2003). DoE (2004) has projected an electrical efficiency of 75 %. Considering Singapore as a key fuel cell research hub (Ho et al., 2004), fuel cell technology would be installed for power generation. When the technology is demonstrated, hydrogen can be produced even from landfill gases and gasification of wastes that would further improve the fuel security for power generation.

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For S6 scenario, by 2013, 10 % of the power would be generated from SOFC-GT using natural gas in addition to 1000 GWh_e from solar PV. The solar PV based power generation would begin in 2006 (as in the S5) while the fuel cell based systems may begin by 2009 by this time SOFC-GT technology would be commercialised. In 2009, 2 % of the power demand would be generated from SOFC-GT. It would further penetrate at two-percentage points per year to reach 10 % of the total power generation by 2013. The SOFC-GT based power generation is considered as DG. The rest of the power would be generated from gas. For S6 scenario, natural gas would increase at 5-percentage points per year as in the S1a. Figures 7.35 and 7.36 show the power generation mix and fuel demand of S6 scenario. The gas demand in 2013 would be about 7.3 million toe, which is 3.4 % lesser than in S1a and is the second lowest fuel demand among all the scenarios (see Table 7.3).

Fig. 7.35. Power generation mix in S6

Fig. 7.36. Fuel demand in scenario S6

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The GHG emissions of power generation mix scenario S6 is shown in Figure 7.37. From 2004 to 2009, emissions would decline at an annual rate of 1.6 %. In subsequent years, the emission would increase at a rate of 3.5 %. The overall emission would decline at a rate of 0.6 % during the selected time horizon, as compared to 0.4 % in S1a. Its primary energy use and cost would increase at a rate of 1.5 % and 4.3 %, respectively (see Figure 7.38). The cost of power supply under the S6 is the highest among all power generation scenarios due to high cost of electricity generation from SOFC-GT and solar PV system.

Fig. 7.37. Emissions in Scenario S6

7.4.8. Results and discussions: Top-down scenarios

The previous section illustrated a range of power generation mix scenarios by considering factors such as fuel-security, environmental friendliness, cost effectiveness, and renewable sources. Table 7.3 summarises the cumulative results of all the scenarios. From the base year 2003, the overall annual average growth rate of the life cycle primary energy use, GHG emissions and the costs are used as criteria for appraisal. Figure 7.38 shows a comparison of all the power generation mix scenarios. It can be seen that it is a difficult task to choose the best power generation mix due to the great diversification in primary energy use, GHG emission and cost. A multi criteria decision-making tool, like AHP can be used for the appraisal (see Section 3.5).

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In the multi criteria decision-making, relative weighing factors are allocated to each of the criteria. A team of multidisciplinary professional and policy makers could decide on weighing factors based on the national relevance, such as fuel-security, emission reduction and cost effectiveness.

Table 7.3. Cumulative energy, emissions and costs in top-down scenarios

Power generation mix Scenarios	Fuel demand	Primary energy demand	Local CO ₂ emissions	Global GHG emissions	Life cycle costs
	(Million toe)		(Million tonnes)		(Billion S\$)
S1a	67.32	72.89	163.30	192.19	52.04
S1b	66.12	71.58	157.39	185.94	51.47
S2a	69.93	75.75	175.84	205.47	53.22
S2b	69.06	74.80	171.49	200.88	52.80
S3a	71.28	77.23	182.36	212.38	53.84
S3b	68.19	73.84	167.35	196.48	52.41
S4a	68.09	73.90	166.48	195.64	51.66
S4b	69.76	75.85	174.30	203.96	51.92
S5a	66.83	72.56	162.09	191.38	53.80
S5b	68.82	74.74	171.65	201.50	54.70
S6	66.49	72.20	161.14	190.29	54.84

Fig. 7.38. Summary of top-down approach power generation scenarios

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For this research, an evaluation approach is used with a simple order of preferences based on the primary energy use, GHG emissions and the cost. A preferences-weighting factor of 1, 2, 3, ... is allocated to each of the power generation mix scenarios based on overall annual growth rate (see Figure 7.38). The lowest growth rate, i.e. the best choice, is allocated with a weighing factor of 1 while the higher growth rates are allocated with a higher weighing factor. For example, in GHG emissions, the scenario S1b is allocated the number 1 as it has the lowest GHG emissions among all the top-down scenarios. S3a is allocated with a factor of 11 as it has the highest GHG emissions growth rates. Based on these preference-weighting factors, the preference of the power generation mix is presented in Table 7.4. By considering all the three criteria with equal importance, the overall weighing factor is calculated as the sum of the individual preference-weighting factors. The overall weighing factors are used to select the best power generation mix. The overall priority matrix is shown in Table 7.5. From the overall weighing factor, the power generation scenarios are discussed.

From the overall priority matrix (Table 7.5), it can be seen that S1b is the best choice in terms of its lowest GHG emission, primary energy use and the costs. Thus, moving towards natural gas is the best choice for Singapore. In such a power generation scenario, the overall emission would decline at a rate of about 1.1 % while the cost would increase at 2.8 % compared to forecasted electricity growth of 4 %. The lowest emissions are due to the predominant use of natural gas. However, the gas based power generation would have concerns about fuel security due to the reliance on a single fuel. If LNG were to be available in the future, then fuel supply may not be a problem. However, the cost of LNG is likely to be higher than piped natural gas (DRPL, 2004). In addition, the primary energy demand for LNG would also be higher.

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If all these factors are taken into account, then the individual weighing factors might change, eventually the overall priority would also change. There is no LNG cost estimates available to analyse a LNG based cost scenario. Hence, the preference of power generation mix in the scenario S1b depends on the trade off between the cost/emissions and the fuel security.

Table 7.4. Preference of power generation mix in top-down model

Order of Preference	Power generation mix scenarios		
	Primary energy use	GHG emission	Life cycle cost
1	S1b	S1b	S1b
2	S6	S6	S4a
3	S5a	S5a	S4b
4	S1a	S1a	S1a
5	S3b	S4a	S3b
6	S4a	S3b	S2b
7	S5b	S2b	S2a
8	S2b	S5b	S5a
9	S2a	S4b	S3a
10	S4b	S2a	S5b
11	S3a	S3a	S6

Table 7.5. Overall priority of matrix of generation mix in the top-down model

Scenarios of power generation mix	Weighing factors with respect to criteria				Overall priority
	Primary energy use	GHG emission	Life cycle cost	Overall weighing factors	
S1a	4	4	4	12	II
S1b	1	1	1	3	I
S2a	9	10	7	26	X
S2b	8	7	6	21	VII
S3a	11	11	9	31	XI
S3b	5	6	5	16	VI
S4a	6	5	2	13	III
S4b	10	9	3	22	VIII
S5a	3	3	8	14	IV
S5b	7	8	10	25	IX
S6	2	2	11	15	V

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The second choice of power generation mix is S1a, which is again switching over to natural gas based power generation. Its overall GHG emission would decrease at a rate of 0.4 % while the cost would increase at a rate of 3.1 %. There is no significant variation between S1a and S1b. In the latter, more gas is used during the earlier period of the selected time horizon. Thus, the S1b showed a cost effective emission reduction.

The third choice of power generation is S4a, in which annually one million tonnes of Orimulsion fuel is used while the rest of the fuel is gas. Though the energy use and GHG emissions of S4 are average among all the scenarios, its lower cost of Orimulsion based power generation bring this scenario to third level. Its overall cost would increase at 2.9 % while the GHG emission would be stable at today's level over the selected time horizon.

The fourth choice of power generation mix is S5a, in which about 2 % power generation would be from solar PV system while the rest from natural gas. From Table 7.3, it can be observed that S5a has the third lowest GHG emission of all the scenarios. Though its primary energy use and GHG emissions are lower than S4a, its higher costs due to solar PV system make this option less preferable than the Orimulsion based power generation in S4a. The overall emission of S5a would decline at 0.5 % but its cost would increase at a rate of 3.8 % per year. The amount of capital required to generate 1000 GWh_e from solar PV systems makes the S5a scenarios over-optimistic.

The fifth choice of power generation is scenario S6. Though it has the second lowest GHG emission favoured by the use of natural gas in combined cycle plants and SOFC-GT and power generation from solar PV system, it has the highest cost among all the scenarios. Its emission would decrease about 0.6 % per year and its costs however increase at 4.3 % due to expensive power generation from solar PV and fuel

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cell. The power generation scenario S6 also relies on single fuel (gas) as the contribution from solar PV based generations is very small, less than 2 %.

The sixth choice of power generation mix is S3b, in which 10 % power generation would emerge from fuel oil. It can be seen from Table 7.3 that its cumulative primary energy use, GHG emissions and the cost are average among all the scenarios. Under this scenario, the overall emission and cost would increase at an annual rate of 1.8 % and 3.8 %, respectively over the selected time horizon.

The seventh and eighth choices are S2b and S4b, respectively. In both scenarios, 10 % of the power generation would emerge either from fuel oil or Orimulsion fuel. From the emission perspective, the use of fuel-oil based S2b appears to be better. Its emission would grow at a rate of 0.6 % while its cost would increase at 3.6 %. However, for the Orimulsion based S4b scenario, the cost would increase at 3 %. However, its emission would increase at 0.9 %. Even though the Orimulsion has higher specific emissions and lower conversion efficiency, its lower cost brings this option on par with fuel oil based power generation.

The ninth choice of power generation is S5b. It is obvious that solar PV based power generations are lower in energy use and emissions. S5b has 10 % power generation from fuel oil for secure fuel supply that masked the effect of solar PV. The overall emission would grow at a rate of 0.68 % while the cost increase at a rate of 4.2 %. Although GHG emission from S5b is lower than the Orimulsion-based S4b scenario, the extremely high cost of solar PV based power generation made it less preferable compared to S4b.

The tenth choice of power generation mix is S2a, in which fuel oil-based power accounts for 10 to 20 % over the selected time horizon. If there were to be disruptions

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in piped natural gas supply due to any unpredicted events such as political vulnerability, price shocks and accidents, then the gas might not be adequate to meet the entire gas demand of the power sector. Then fuel oil or other source should be a part of the power generation mix. Under such circumstances, the emission growth rate would be about 1.1 %. In addition, the costs would also be higher at 3.6 %. Nonetheless, the costs are still lower than solar PV based power generation mix of S5a or S5b.

The lowest choice of power generation mix is S3a, in which 20 % of fuel oil based power generation would be maintained. Thus, it has the highest emission growth rate of 1.8 % and cost of 3.8 %. However, fuel is readily available since Singapore is an refinery hub. Thus, a trade-off between fuel security and emission/cost should be made. A balanced generation mix of oil-fired steam turbine and gas-fired combined cycle plants would enhance the power supply security and reliability. If fuel security is important, then fuel oil has to be a part of the power generation mix.

7.5. Integrated approach of power generation planning

An integrated framework has been developed by incorporating energy efficiency-based bottom-up measures into the top-down model. The DCS and cogen are selected as potential bottom-up measures for the integrated framework. Three scenarios of bottom-up measures are constructed and integrated into selected top-down power generation scenarios. Their primary energy use, GHG emissions and costs are estimated and compared with the top-down scenarios. The same power generation mix of the top-down scenarios are used in the integrated scenarios. Therefore, the changes in the cumulative primary energy use, GHG emissions and the cost can be directly compared.

7.5.1. Bottom-up measure 1: DCS

As discussed in Section 5.6.1, it is difficult to generalise the energy saving of DCS. Even if the DCS is compared with the most efficient BSCS, there would still be a potential to conserve energy/emissions to about 5.5 %. For one scenario of bottom-up measures, it is assumed that 30 % of the future cooling demand of commercial building would be met through DCS. It is known that the efficiency of chiller system installed in the future could be on par with the efficiency of chillers used in DCS plant. Thus, the potential energy saving of using the DCS would be only from its full load operation and thermal storage systems. Thus for this measure, a 5 % net energy saving is assumed²⁷. Perhaps this energy saving would be even achieved with thermal storage systems in BSCS.

Another scenario considered for the bottom-up measures is that BSCS operating at a *CoP* of lower than 3 (1.2 kW/RT) would be replaced/retrofitted with new chiller systems of *CoP* of 4.5 (0.7-0.8 kW/RT) or switched over to DCS. There is a substantial potential to improve the energy efficiency in BSCS (Jayamaha, 2004; Foo and Ramany, 2004; Tay, 2004). Even in new BSCS, over 38-43 % energy savings were achieved with better control systems and management (Tay, 2004). There is no database on the chiller population in Singapore to estimate the saving potential of the inefficient chillers. To validate this model, inefficient chillers are assumed to be about 20 % of the total chiller populations²⁸ and they would be replaced with efficient chillers or switch over to DCS by 2013 at a rate of one-percentage points per year. For these measures, 25 % in energy saving is assumed.

²⁷ The actual energy saving from the full load operation of chillers could be higher. In DCS plant, a part of the energy is used in the distribution pumps and thermal losses in storage and T&D of chilled water.

²⁸ The total chiller population is assumed to be normally distributed within the efficiency range of 0.6-1.4 kW/RT with a mean of 0.9 kW/RT.

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The above two bottom-up measures are altogether considered as one bottom-up measure '1a'. Their net reductions in the primary energy use and GHG emissions are calculated from the national average energy use/emission of electricity generation in the previous year [see Equations (3.32) and (3.33)]. The life cycle costs are accounted based on actual costs after including incentives and administration costs.

Though the cost of DCS is lower than BSCS, a worst case cost is used for this particular scenario i.e. the interest rate of 7 % for capital cost of DCS plant and the same electricity tariffs for BSCS and DCS. Thus, the cost of DCS would be about 4 % higher than BSCS on RTH basis (see Section 5.6). Since the promotion and adoption of the bottom-up measures are often difficult (see Section 2.4.2), a financial incentive of one-to-one cost subsidy is also included. In the one-to-one cost subsidy, each unit of electricity conserved would be rewarded with electricity generation cost. In the integrated framework, the cost of electricity for subsidy is taken from the pervious year's average electricity generation cost. In addition to the financial subsidy, a programme administrative cost of 10 % is accounted in this scenario. This bottom-up measure is integrated into selected top-down power generation scenarios and the results are discussed in Sections 7.5.4 to 7.5.6.

7.5.2. Bottom-up measure 2: Cogeneration

Cogeneration (production of power and steam) has been successfully demonstrated in Singapore (SembUtilities, 2004). For the cogen bottom-up model, it is assumed that the existing combined cycle plants or future plants would be cogen plants. In the case of existing plants, steam from HRSG would be directly supplied to the industries, instead of using it in the steam turbine. Planning for a cogen plant requires detailed analysis to identify potential (steam/hot water) consumers. There is

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potential for cogen in Singapore based on the report by the Sub-Committee on Manufacturing (2002) of Singapore's Economic Review Committee.

For cogen, the efficiencies of gas turbine and HRSG are considered as 38 % and 70 %, respectively. This works out to a cogen efficiency of 81 % compared to the combined cycle plant efficiency of 55 %. The steam from the cogen plant would replace industrial steam generating boiler with an efficiency of 80 %. Therefore, each unit of electricity generated from the cogen plant would conserve about 0.57 kWh_t of primary energy [see Equation (5.13)]. This is credited to the power sector's primary energy use and emissions. The emissions are estimated based on gas although the steam could replace the steam from oil-fired boilers.

As far as costs are concerned, the cogen plant would require additional capital costs on steam distribution pipelines. Due to dearth of data, it is assumed that the cost of the cogen plant would be same as that of a combined cycle plant. The cost of the steam turbine and its generator in a combined cycle plant would offset the cost incurred in the steam distribution pipelines to a certain extent. The LCC of the electricity generated from the cogen plant is calculated based on the gas turbine efficiency, which works out to be about 9.05 ¢/kWh_e (@38 % efficiency, 8.7 S\$/MMBTU). The cost of steam produced from the cogen plant is also credited to the electricity cost. The cost of steam is calculated as 3.67 ¢/kWh_s from the fuel (gas) cost alone as all the capital costs of the cogen plant are included in the electricity cost. The net weighted average cost of the electricity from the cogen plant is about 6.1 ¢/kWh_e which is lower than the cost of electricity generation from the combined cycle plant of 6.63 ¢/kWh_e (@ 55 % efficiency, 8.7 S\$/MMBTU).

For cogen, two scenarios of bottom-up measures viz. 2a and 2b are constructed. In 2a, 10 % of the power would be generated from the cogen plant during the selected

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time horizon, 2004-2013. The cogen-based power generation would begin from 2005. For scenario 2b, 15 % of the power would be generated from the cogen plant by 2013. This would begin with 2 % in 2005 and reach 15 % by 2013. These two scenarios of bottom-up measures are integrated in the selected top-down model. In the integrated scenarios, it is assumed that the cogen plant would replace the combined cycle plant. Therefore, there would not be any change in the fuel mix in power generation due to the inclusion of cogen.

7.5.3. Integrated scenario study

The scenarios of bottom-up measures described in the previous sections are integrated into selected top-down scenarios viz. S1b, S4b and S3b, of the power generation mix. It is aimed to analyse the significance of the integrated approach of the power generation planning compared to the top-down approach. The integrated approach scenarios are denoted by the acronym IAYy_SXx. The first term denotes the scenarios of bottom-up measure and the second term represents the top-down scenario. For example, the integrated scenario IA1b_S1b combines the bottom-up measure '1a' (i.e. DCS) and top-down scenario S1b (see Section 7.4.2). For the integrated scenarios, the cumulative primary energy use, GHG emissions and the costs during the selected time-horizon 2003-2013 are estimated.

7.5.4. Integrated scenario: Bottom-up measures in S1b

Figure 7.39 shows GHG emissions of the integrated scenarios of the three bottom-up measures in S1b. As can be seen, there are significant variations between the top-down scenarios and integrated scenarios. For example, in S1b of the top-down scenario, the GHG emission declined at rate of about 1.1 % whereas in the integrated scenario it would decline at 1.2 % in IA1a_S1b (DCS) and 3.2 % in IA2a_S1b (cogen). Figure 7.40 compares the overall growth rates in GHG emissions, primary energy use

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and the cost from base year 2003. The impact from the DCS-based IA1a_S1b is not as significant compared to the cogen. Due to inclusion of one-to-one cost subsidy and 10 % administrative costs in the DCS based bottom-up measure (1a) (see Section 7.5.1), the total cost of power supply is increased in IA1a_S1b.

Fig. 7.39. GHG emissions in integrated scenario of S1b

Fig. 7.40. Top-down versus integrated of scenarios of S1b

In cogen-based integrated scenarios, GHG emission would decline at a rate of 3.2 % compared to 1.1 % in S1b. This integrated scenario is also cost effective as the cost incurred in power supply would increase at an annual rate of 2.75 % in IA2a_S1b compared to 2.88 % in S1b. If the cost of steam is not credited in the power generation costs, then the cost would increase at an annual rate of 3.33 % in IA2b_S1b.

7.5.5. Integrated scenario: Bottom-up measure in S3b

GHG emission of integrated scenarios that is constructed with the three bottom-up measures described in Sections 7.5.1 and 7.5.2 and the top-down scenario S3b is shown in Figure 7.41. Since fuel oil is a reliable fuel in terms of its availability in Singapore, it may have to be a part of the power generation mix. In such a case, the GHG emission would increase annually by about 0.12 % during 2004-2013. Though DCS-based bottom-up measure would not contribute to emission reduction, cogen will have significant impacts on overall emissions.

Figure 7.42 shows a comparison of the integrated and top-down scenarios. In the cogen based integrated scenario (IA2a_S3b), it would be possible to reduce the emission up to 1.8 % even fuel oil were to be used. In the IA2a_S3b, the emission would decline from today's level and reach the level of 1995-96 by 2006. However, it would bounce back to today's level by the end of the selected time horizon. But, for the same power generation mix, GHG emission of the top-down scenario S3b would reach to the 2000 level - the highest in the past decade by 2013.

Fig. 7.41. GHG emissions in integrated scenarios of S3b

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Fig. 7.42. Top-down versus integrated of scenarios of S3b

7.5.6. Integrated scenario: Bottom-up measures in S4b

Figures 7.43 and 7.44 show the GHG emission and the overall comparison of the integrated scenarios that comprises the three bottom-up measures in the top-down scenario S4b. In the top-down scenario S4b, which uses Orimulsion fuel up to 10 % of the total power generation, the overall GHG emission would increase at a rate of 0.95 %. In the integrated scenario, it would decrease at a rate of 0.92 % per year (see in Figure 7.44) if cogen is explored. The life cycle cost would also decrease slightly under this scenario. It can be seen from Figure 7.43 that the GHG emission in 2006 would be at the level of 1996-97. It would, however, never reach that level in the Orimulsion-based power generation scenario (S4b).

Fig. 7.43. GHG emissions in integrated scenarios of S4b

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Fig. 7.44. Top-down versus integrated of scenarios of S4b

7.6. Results and discussions: Top-down versus integrated approach

GHG emissions from Singapore’s power sector have been declining since 2000. However, it would increase in the near future depending on the power generation mix. Figure 7.45 summarises the overall growth rates in the primary energy use, GHG emission and the cost of all power generation scenarios studied in the top-down and integrated approaches. In the top-down based power generation planning, only in four power generation mix scenarios, namely, S1a, S1b, S5a and S6 would the overall GHG emissions decline from today’s level (see Figure 7.45). These four scenarios are 100 % fuel switching to natural gas or solar PV based power generation or combination of them. Though switching to natural gas is cost effective, the solar PV is not cost effective. Therefore, in the top-down model, either switching over to natural gas or inclusion of solar PV based power generation would be the only possibilities to reduce GHG emissions in Singapore’s power sector.

If 100 % reliance on gas for power sector is considered as a concern to the fuel security or reliability of power sector, then oil and/or Orimulsion should be part of the power generation mix. Under such circumstances, GHG emission reduction would not be possible in the top-down based power generation scenarios. However, in the

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integrated scenarios, there would be a potential to reduce GHG emission even if the Orimulsion or fuel oil is used, e.g. IA2b_S3a or IA2a_S4b. At the same time, they are cost-effective, despite including the financial incentives for the bottom-up measure. Therefore, the integrated approach can significantly contribute to the cost-effective emission reductions and is far better than the supply based top-down based approach of power generation planning.

If strategies are developed to promote bottom-up measures with financial incentives, the emission would decline further. Due to incentives, the cost involved in power supply would increase. Nonetheless, the integrated approach can be more effective when it is compared with expensive supply options such as solar PV based power generation scenarios (S5a). Thus, this integrated framework can be used for parametric studies to determine the trade off between emission and costs.

Fig. 7.45. Comparison of top-down and integrated power generation scenarios

7.7. Summary

The top-down model and integrated framework are developed and various power generation scenarios are studied. The scenario results of the top-down model and integrated framework have shown that the integrated approach of power generation planning is more effective than the top-down approach in terms of fuel security, emission reduction and cost effectiveness.

The supply based top-down scenarios reveal that for a 4 % annual electricity growth during 2004-2013, it would not be possible to reduce GHG emissions from power sector from today's level unless and until power generation switches over to 100 % natural gas. In a 100 % gas based power generation, the overall emission would decline at an annual rate of about 1.1 % while the cost would increase at 2.8 %. Switching over to 100 % gas require additional sources of gas supply as the current gas import would not be adequate to meet the power sector's demand. If 100 % gas based power generation is considered as a concern to the fuel security and reliability of power sector, then fuel oil/Orimulsion should be part of the power generation mix. In such cases, it would not be possible to reduce emissions from today's level. If solar PV systems were to supply 2-3 % of the total demand, which is consider the maximum it could provide, the resulting change in GHG emission would be insignificant and cost ineffective.

The integrated scenarios reveal that using of fuel oil/Orimulsion for a 10 % of the power generation mix, there would be an emission reduction of about 0.9-1.8 % from today's level if 10 - 15 % of the power is generated from cogen. However, in absence of the cogeneration, the emission would increase at a rate of 0.10 - 0.95 %. Therefore, improving the energy efficiency would be the only option to limit GHG emission from Singapore's power sector.

8. Conclusions and Recommendations

8.1. Introduction

This chapter summarises the overall output from this research. Its significances are discussed in the context of scenario studies of the Singapore power sector. Recommendations for emission reduction in Singapore are presented. Some suggestions are made to extend this research.

8.2. Significances of the research

8.2.1. LCA-LCCA models

LCA and LCCA models have been developed to establish life cycle primary energy use, GHG emissions and cost inventories for the power generation and consumption technologies. The LCA model took into account various operational parameters such as efficiency, plant lifetime and load factor. The LCCA model has options to change the variables such as capital cost, interest rate, O & M cost, fuel price, price escalation, inflation (discount rate), plant efficiency, load factors and lifetime. The LCCA model also considered capital equipment with varying lifetimes (see LCCA of DCS in section 5.4.5). Using these LCA and LCCA models, life cycle inventories have been established for potential power generation technologies in Singapore (see Table 7.2). Simplified correlations have also been established to calculate the life cycle primary energy use, emission and cost from the plant net efficiency. The LCA and LCCA models have also been customised for DCS and BSCS. The same models/methodologies can be replicated for other technologies and energy services.

The LCA's of an oil/Orimulsion-fired steam turbine plant revealed that hidden processes, such as upstream processes of fuel-oil production and transportation,

consume about 9-11 % additional energy on top of the fuel embedded energy while the hidden emission is about 12 %. In gas-fired combined cycle plants, the hidden processes account for 8 % and 18 % of the life cycle energy use and emissions, respectively. Therefore, including LCA is important in accounting for environmental impacts and energy use. In cases of the fossil based power generation technologies, the upstream process of the fossil fuels account for a significant portion of the hidden energy use and emission. However, they are insignificant in the construction and decommissioning phases. A similar trend was also observed in district cooling plants where electricity is the major source of energy in the operational phase. Considering the limitations of data availability and time required to carry out a LCA, accounting for the upstream process of the fossil fuel production only would be good enough instead of performing a complete LCA. However, this rule of thumb cannot be applied to non-fossil fuel-based systems, such as solar PV, wherein the construction phase is the most important.

8.2.2. Top-down models

A top-down model has been developed. It can be used for scenario studies in the power sector. For various power generation mix scenarios, their fuel demand and CO₂ emission can be forecasted. In such scenario studies, variables such as power demand growth, fuel mix and power generation efficiencies are included. It can also account for T&D losses that allow the inclusion of DG in the scenario studies. In conjunction with the LCA and LCCA models, the top-down model can forecast the life cycle primary energy use, GHG emissions and the cost incurred in the entire power sector. It is a useful tool for parametric studies to determine power generation mix scenarios in the event that specific GHG emission obligations or cost-effectiveness have to be fulfilled. Since this model uses cost inputs from the LCCA model without

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concerning about the time value of money, the year-to-year growth or overall changes in the cost can be easily compared with alternative power generation scenarios.

This top-down model is applied to Singapore's power sector and power generation scenarios have been studied (see Section 7.4). The supply-based top-down scenarios show that the GHG emissions from the power sector have been decreasing since 2000. This results from rapid fuel switching from fuel oil to natural gas. However, it would increase in the near future to cope with increasing power demand. The emission growth rates would depend on the fuel mix. The various power generation mix scenarios reveal that it would not be possible to reduce the GHG emissions from today's level, unless and until power generation switches over to 100 % natural gas (see Figure 7.38). In a 100 % natural gas based power generation, GHG emission would decrease at an annual rate of 1.1 % from today's level during 2004-2013 when the annual electricity demand grow at 4 %. The total cost incurred in power supply would increase at an annual rate of 2.9 %. This would be the most cost-effective power supply from the top-down approach. However, it would require additional sources of gas supply as the current gas import would not be adequate to meet the power sector's demand. 100 % gas based power generation would also pose concerns on fuel security, especially during oil price²⁹ shocks or political vulnerabilities. If oil or Orimulsion were to be a part of the power generation mix, it would not be possible to reduce GHG emissions from today's level (see scenarios S3 and S4 in Sections 7.4.4 and 7.4.5). If solar PV based power generation were to be explored to supply up to 2-3 % of the total demand during the selected time horizon, there would not be any significant change in the GHG emission. In addition, it would not be a cost effective options in terms of its capital cost and power generation costs

²⁹ The natural gas price is pegged to fuel-oil price.

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(see Section 7.4.6). Therefore, if Singapore has to limit its GHG emission from the power sector, there would not be any supply-based options that will take into account fuel security, cost effectiveness and emissions.

8.2.3. Integrated framework

In the top-down model, two energy efficiency-based bottom-up measures, namely DCS and cogen, are included and an integrated framework has been developed. This framework is capable of considering the DSM and also took into account any subsidy/administrative cost incur in the DSM. Thus, this framework can be used for parametric studies to optimise the emission and cost from both the top-down and bottom-up measures. For example, in the case of any GHG emission target, it can be used to analyse various fuel mix for power generation by including the bottom-up measures with financial incentives or programme administration costs. This would enable one to find the cost-effective power generation mix. At the same time, it can also be used to evaluate the financial incentive for energy efficiency (bottom-up measures) and/or renewable technologies (top-down measures).

This integrated framework is applied to Singapore's power sector and integrated power generation scenarios are studied. The integrated power generation scenarios show that by incorporating bottom-up measures in power generation, we can obtain different perspectives on emission and costs. The top-down scenarios showed that switching over to 100 % natural gas would be the only option to reduce the GHG emission. However, the integrated scenarios show that emission reduction would be possible even if fuel oil or Orimulsion are used. Therefore, energy efficiency would be the only option for Singapore to limit its emissions. For example, using a 10 % fuel oil/Orimulsion in the power generation mix, there would be an emission reduction of about 0.9 - 1.8 % from today's level if 10 - 15 % of the power is from cogen in the next

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10 years (see Sections 7.5.5 and 7.5.6). DCS would also contribute to cost-effective emission reduction if it replaces the most inefficient BSCS even after providing financial subsidies. There would be other potential areas to improve energy efficiency. The Inter-Agency Committee on Energy Efficiency, Singapore (IACEE, 2001) has made numerous recommendations. These recommendations can be included in the bottom-up model using the same methodology and their impacts can be studied using the integrated framework.

Therefore, the models developed in this research would be useful tools to perform scenario studies at the power generation planning level to predict fuel demand, CO₂ and GHG emissions, and the cost of power supply under various power generation mix. The same methodology would be replicable to other energy sectors.

8.3. Recommendations

In the almost 100 % fossil fuels-dependent Singapore power sector, improving the energy efficiency would be the only option to reduce GHG emission from the power sector. In line with IACEE (2001)'s recommendations, the following areas can be focused to improve the energy efficiency.

8.3.1. Cogeneration

Cogen would be one of the most cost-effective options to limit Singapore's energy use and emissions without any compromise. There is potential for cogen as by the Sub-committee on Manufacturing (2002) of Singapore's Economic Review Committee. Large-scale cogen has been demonstrated in Singapore. Therefore, it should be further expanded in all industrial clusters. The policy should also encourage distributed cogen, in which the consumer can export excess electricity to the grid. There is a need for extensive study to synchronize industrial heat demand and power generation.

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The possibilities/feasibilities of providing hot water service for commercial customers such as hotels, restaurants and food courts should be explored. Hot water service would often replace electric boilers and their energy saving and emission reduction would be higher (see Section 6.4). Careful pricing of hot water service is important to tap this potential as energy pricing sometime discourage the efficient use of energy resources (see Section 8.3.4)

8.3.2. Air-conditioning

In Singapore, about 22 % of the electricity is used in air-conditioning of commercial/service sector buildings. The opportunities for energy efficiency improvement in air conditioning should be explored. Potential alternative fuel/technologies such as cogen, distributed DCS, solar radiation for cooling applications can be identified. Specific policy instruments such as standards and energy auditing may be developed to improve the energy efficiency of BSCS.

DCS can be recognised as a promising future technology if the large quantity of waste heat from power plants could be utilised for the cooling applications. As an alternative to DCS, thermal storage in BSCS should be encouraged. By introducing thermal storage in cooling application, part-load inefficiencies can be minimised. At the same time, the peak electrical demand can be reduced. As the result, the difference between peak and off-peak electrical demands would be reduced. This would improve the overall efficiency of electricity generation. The expansion plan for power grid extension would also be avoided or delayed. All these benefits can be realised at the expense of energy (heat) losses and capital costs on thermal storage systems. Therefore, the trade-off between the electricity generation efficiency at peak hours and thermal storage efficiency should be studied.

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Instead of chilled water storage, ice storage offers the possibility of reducing storage volume due to its large enthalpy. Ice storage systems requires a one-fifth the volume of chilled water storage system. However, the energy efficiency (*CoP*) of ice forming chillers is lower than the chilled water-producing chiller. The capital costs of such plants could be higher. When energy is discharged from the ice storage tank using secondary fluids and heat exchangers, additional energy losses would occur. Therefore, the energy efficiency and cost effectiveness of ice storage should be studied.

The heat rejected from the chillers system can also be used for hot water applications in industrial and commercial sectors such as hotels, eating places and restaurants.

In residential sector, air-conditioning has been estimated to account for about 31 % of residential electricity use and 6.2 % of Singapore's electricity consumption (EMA, 2002b; EMA, 2004c). Through more awareness and education such as an energy label programme for air conditioners and refrigerators (NEA, 2002), energy efficiency can be promoted.

8.3.3. Solar thermal - an alternative to solar PV

Although solar energy cannot be a complete substitute for oil or natural gas, efforts can be taken to explore all possible means to harness available solar radiation. Instead of harvesting solar radiation for power generation, it can be used for thermal applications e.g. hot water. In the residential sector, the electricity used for hot water applications is estimated to be about 8-10 %, which is about 1.9 % of Singapore's total electricity consumption (EMA, 2002b; EMA, 2004c). To produce 1 % of the country's total electricity from Solar PV would require an installed capacity of about 300 MW_p which would cost billions of dollars. Furthermore, this will not result in significant

reduction in the overall GHG emission (see Scenarios S5 in Section 7.4.6). Eventually, the electricity would still be used for hot water applications. Considering the high efficiency of solar thermal collectors (> 70 %) compared to solar PV system (< 10 %), solar thermal system are more energy-efficient and its emission reduction potential would be higher. Therefore, the installation of solar thermal collectors on the rooftops of high-rise apartments should be explored. Even if the installation of pipeline reticulation to supply hot water within an apartment block solar thermal might be cost effective provided LCCA is used for appraisal. Other possible means to use solar hot water systems in the commercial sector should also be explored.

8.3.4. Pricing mechanism

In Singapore, the deregulated electricity market is aimed at creating market competition thereby reducing the electricity price and improving the electricity generation efficiency. A “Vesting Contract” is an effective pricing instrument (EMA, 2004d) to drive the power generation towards energy efficient operation although it also encourages ‘cheaper’ fuels such as Orimulsion which emits higher levels of CO₂. Price regulations should also encourage energy efficiency at the demand side.

One of the barriers that discourage the use of alternative fuels to electricity is the market pricing mechanism. For example, gas is one of the best alternative to electricity for hot water applications. However, in Singapore, electricity is cheaper than town gas. Electricity and town gas prices in 2003 were 15.24 ¢/kWh_e and 15.23 ¢/kWh_t, respectively for residential consumers. For industrial/commercial consumers, the electricity price was 6.34 - 10.85 ¢/kWh_e while the town gas price was 13.73-14.23 ¢/kWh_t (EMA, 2004). Thus, electricity becomes a cheaper energy source for hot water applications especially in the commercial sector such as hotels and restaurants. Considering the higher efficiency of electrical heater/boiler relative to gas-fired boilers,

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the electricity is the most cost effective fuel. Though the energy efficiency of electrical heater/boiler is the highest, its life cycle energy and exergy efficiencies are the lowest (see Table 6.1). Hence, the current pricing mechanism in Singapore discourages the efficient use of energy resources. Therefore, it is important to monitor pricing of electricity, gas and energy services such as DCS and steam to promote demand side energy efficiency. Even if the policies do not provide incentives, they should not discourage energy efficiency. Due consideration should therefore be placed on price regulation to improve the overall energy efficiency at the supply and demand sides. ELCA can be used as a tool for the pricing of fuels and energy services (see Section 6.4).

8.3.5. Policy instruments

Promotion and implementation of bottom-up measures would be a challenge (see Section 2.4.2). Policy instruments such as customer education, technical support and demonstration programs can encourage end-users to adopt the latest technologies and more energy-efficient equipment. One of the main barriers to the adoption of energy efficiency measures lies with the traditional economic appraisal. If the life cycle based analysis is used, it can be overcome to a certain extent. Nonetheless, effective financial/fiscal incentives should be established. The great advantage of energy efficiency is its long-term benefits, which can be effective regardless of power supply scenario. The effective and efficient utilization of energy resources can also contribute to sustainable development. Hence, energy efficiency should be incorporated in the national energy policy.

Considering that Singapore is an energy intensive economy and its almost 100 % reliance on fossil fuel, the country should have a long-term energy policy that describes future perspectives of energy supply and demand. To ensure reliability of

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power supply in terms of cost effectiveness, fuel security and environmental friendliness, the power sector should also map out a long-term fuel policy.

The lack of energy data is one of the main constraints to the monitoring of developments in energy sector. Therefore, a national energy database centre should be established. It should be able to provide energy related information and data such as institutional set-up, primary energy supply and demand, fuel mix, sectoral end energy consumption pattern (see Section 3.4.1). Considering that Singapore is a small island nation, establishing such a database would not be difficult. However, initiatives should be taken at the first instance. Any one of the institutions should be made responsible for the collection and publication of energy data. Perhaps, the universities would be the best choice to compile and publish the data.

8.4. Suggestions for extension of this research

In the LCA model, plant efficiency and load factor are included as independent operational variables. However, they are dependent variables as the efficiency vary with load. Therefore, the LCA model can be improved to account for the dynamic efficiencies. This can also be incorporated into the LCCA model. This would enable one to differentiate the peak and off-peak load power generations in terms of its energy, emission and cost. It facilitates the more precise study of the impact of DMS.

The bottom-up measures recommended in Section 8.3, such as distributed DCS, solar thermal and use of gas for hot water application should be developed into a bottom-up model. They can then be incorporated into the integrated framework so that it would be a unique model for power sector scenario development and parametric studies. The methodology of integrated approach can be replicated to other energy sectors to develop cross-sectoral synergy. This would enable the efficient use of energy

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resources in all sectors of the economy. It would also facilitate the estimation of the relative national environmental cost by considering all the available options in the top-down and bottom-up models.

In the case of the cross-sector framework, the end use applications would be of different energy type. Therefore, selection of alternative fuels would be identified based on the method of exergy analysis outlined in Chapter 6. ELCA should also be included in the integrated framework. By considering all these factors, this research can be further extended and a holistic model developed.

Though this research was aimed at considering primary energy use as an indicator of fuel security, the total primary energy use did not reveal any information of fuel type. Therefore, they should be characterised based on the fuel type. This modification can also be incorporated into this model.

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