AN OPTIMIZATION MODEL FOR NO_X AND SO_X EMISSION REDUCTION IN POWER GENERATION

BY

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DEDICATION

This work is dedicated to my beloved **parents**, my **wife**, my **brothers**, my **sisters**, my **daughter***Manar and* my **son***Taym*.

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ABSTRACT

Full Name **MOHAMMED KARAMA SAEED ALSEBAEAI**

Title of Study **AN OPTIMIZATION MODEL FOR NOx AND SOx EMISSIONS REDUCTION IN POWER GENERATION**

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The power generation sector is considered as one of the major contributors to air pollution. There are different air emissions that can be emitted from power generation and among these are NO_XandSO_Xemissions which will be the focus of this research.In thisstudy,an optimizationmodel was formulatedand written in a general format. The objective of this model is toselect the best pollution control strategy for the power generation to reduce NOxand SO_X to specific level while meeting the electricity demand at minimum cost. Three different mitigation options were considered to reduce NOx and SOx and these are: fuel balancing, switching and implementing different controltechnologies.

The model is illustrated in two case studies (1 and 2) taken from Ontario Power Generation, Canada.The two cases consider NOx and SOx emissions respectively. Mainly in this work will be focus on SO_2 emissions.For the NOx case when we consider two options (fuel balancing and switching), it was found that fuel switching is the best option of choice for reduction targets from 5 up to 30%.However, by considering all mitigation options, the result shows that applying SCR technology is the best option to reduce NOx emissions. The results of other case which considers SO_2 emissions and involves fuel balancing and switching show that the optimum option for SO_2 reduction is fuel switching

for higher reduction targets (from 5 up to 75%).On the other hand, for the case in which all options are considered,the results show that applying FGD technology is the best option to reduce SO_2 emissions and it can achieve up to 85% SO_2reduction.Sensitivity analysis was carried out in both case studies, and the result indicates thatthe only affected variable is the total annualized cost.

THESIS ABSTRACT (ARABIC)

ملخص الرسالة

الاسم : محمد كرامه سعيد السباعي

عنوان الرسالة: تطوير برنامج رياضي أمثل للحد من انبعاثات أكاسيد النيتروجين والكبريت من محطات توليد الطاقة

التخصص: هندسة كيميائية

يعتبر قطاع توليد الطاقة الكهربائية من أكبر المساهمين في تلوث الهواء. فهناك ملوثات مختلفة يمكن ان تنبعث من هذه المحطات ومن بين هذة الانبعاثات أكاسيد النيتروجين والكبريت و التي ستكون محور هذه الدراسة.في هذا البحث تمت صياغة نموذج رياضي أمثل ومكتوب بشكل عام .الهدف من هذا النموذج هوتحديد أفضل الحلولاثناء توليد الطاقة للحد من تراكيز الملوثات (أكاسيد النيتروجين و الكبريت) إلى التراكيز المستهدفةفي حين تلبية الطلب على الكهرباء بأقل تكلفة ممكنة.ولقد تم دراسة ثلاث طرق للحد من هذة الاكاسيد وهذه الطرق هي: التوازن بين الوقود, استبدال الوقود وتطبيق تكنولوجيا التحكم المختلفة.

هذا النموذج الرياضي تم تطبيقةعلى دراستين لحالتين مأخوذة من محطات توليد الكهرباء في ولاية أونتاريو، كندا. هذهالحالتين تهتم بانبعاثات أكاسيد النيتروجين و الكبريت على التوالي.من أهم انبعاثات اكاسيد الكبريت التي يهتم بها هذا البحث هي انبعاثات ثاني أكسيد الكبريت.ومن خلال البحث في دراسة حالة أكاسيد النيتروجينوعندما طبقنا خياري (موازنة الوقود واستبدالة)، وجدنا أن استبدال الوقود هو أفضل خيار للحد من تراكيز أكاسيد النيتروجين من5 - 30 %.ولكن من خلال تطبيق كل خيارات ووسائلالحد من هذة الانبعاثات، أظهرت النتائج أن تطبيق تكنولوجيا التقليل الانتقائي الحفاز(SCR) هو الخيار الأفضل للحد من هذةالانبعاثات.

في حين نتائجدراسة الحالة الأخرى التي تأخذ بالاعتبار انبعاثاتثاني أكسيد الكبريت والتي تم فيها تطبيق خياري توازن الوقود واستبداله, أظهرت أن الخيار الأمثل للحد من هذة الأنبعاثات بنسب تتراوح من 5 – 75% هو استبدال الوقود .أما بالنسبة للحالة التي أخذنا فيها بنظر الاعتبار كل خيارات الحد من انبعاثات ثاني اكسيد الكبريت ، فقد بينت النتائج أن تطبيق تكنولوجيا ازالة الكبريت من غاز المداخن(FGD) هو الخيار الأمثل وأنه يمكن أن نحد من هذة الانبعاثات الى نسبة تصل الى85%. وقد أجرينا تحليل في كلتا الدراستين، وكانت النتيجة تشير إلى أن هذا التحليل لة أثر على التكلفة الإجمالية السنوية.

CHAPTER 1

INTRODUCTION

1.1 Background

The power generation industry is the lifeblood of the developed country. It became one of the most important global industries generating electricity for all other industriesas well as all people rely profoundly on it in their daily lives. Electricityhas been often generated at power stations since1881.

The earliest power generation stations used reciprocating steam engines to generatepower. But, there was a difficulty to develop the high rotational speeds needed to drive a generator effectively. In 1884, Sir Charles Parsons invented the steam turbine to overcomethis difficulty. Coal was usually the fuel for these plants, used to raise steam in a boiler. Inthe second half of the nineteenth century, much of the key work on different turbine types used was carried out to capture power from flowing water. Both the spark-ignitionengine and the diesel engine also had been developed by the beginning of the twentieth century. As a way of generating power, work also began on the useof wind turbines before World War II. But until the beginning ofthe 1950s, steam turbine power stations burning offossil fuels, together with hydropower stations, provided the bulk of the globalpower generation capacity(Breeze 2005).

In the 1950s, the age of nuclear power which is the most contentious of all the forms of power generation was born. Nuclear power grew rapidly in the USA up to the late1970s.The UK, France and Germany all began to build up significant nuclear generating capacities too. In the Far East, Japan, Taiwan and South Korea worked more slowly. Russia developed its own plants andChina began a nuclear program, as well asIndia. From the end of the 1970s, particularly in thewest, the progress of the nuclear industry has slowed dramatically while in Asia the story still alive(Breeze 2005).

In 1973, a major upheaval in world oil pricescaused by the Arab– Israeliwar .at that time, oil had also become a major fuel for power stations. Countries thatwere burning it extensively began to seek new sources for generating electricityand interest in renewable energy sources began to take off. As result of rising oil prices, a wide varietyof different alternative energy technologies has been investigated such as hot-rockgeothermal power, wave power and the use of ethanol derived from crops instead ofpetrol or oil. However the main winners were wind power and solar power. After development and by the end of the century both solarand wind technologies had reached the stage where they were both technicallyand economically workable(Breeze 2005).

In the 1980s, wide-ranging measures toreduce environmental emissions from fossil-fuel-fired power plants were implemented by the industry. During the 1980s and 1990sthe gas turbine had become one of the most widely used primemovers for new power generation applications – both base load and demandfollowing – practically everywhere. Theconfiguration which combines gas and steamturbines in a single power station known as the combinedcycle plant. This configuration has become the main source ofnew base-load generating capacity in many countries where natural gas isreadily available, and also can provide a cheap, high-capacity, high-efficiency power generation unit with low environmental emissions(Breeze 2005).

The importance of new and renewable sources of electricityhas been seen renewed in the first years of the twenty-first century. Fuel cells, a technicallyhighly developed but expensive source of electricity, are approaching commercialviability.

Also, three different technologiesdesigned toextract energy from the world's seas and oceans. They are ocean thermalenergy conversion (OTEC), wave energy conversion and ocean current(Breeze 2005).

A thermal power plant operates similarly to how nuclear power plants and petroleum power plants work. The difference is the source of heat. The components of these plants are almost the same For example, The main components of a modern coal-fired power plant can be shown in Figure 1.1 .They can be divided into the following plant sections(Spliethoff 2010):

- Fuel supply and preparation
- Steam generator with furnace
- Turbine and generator
- Heat rejection unit, condenser, cooling tower
- Units for emissions reduction and disposal

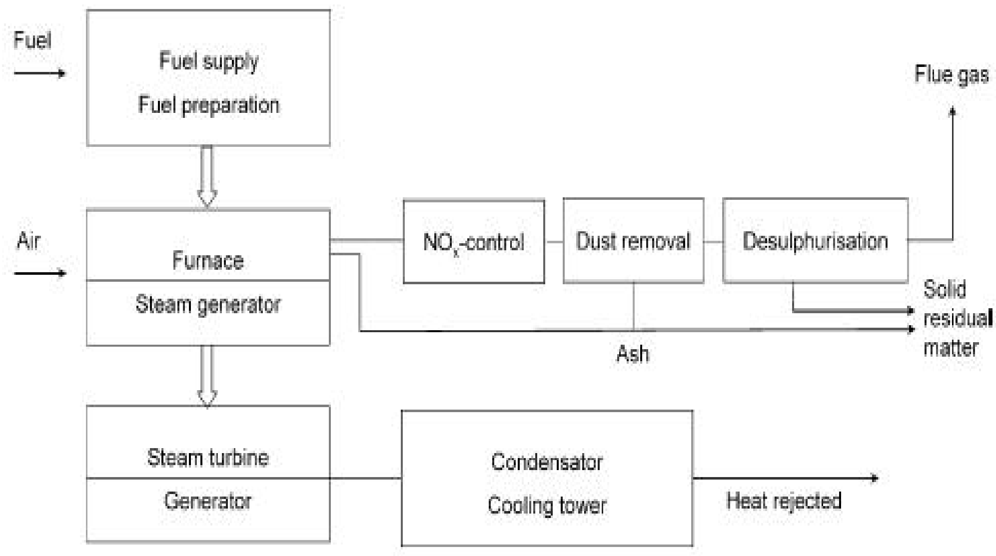

Figure 1.1components of a steam power plant (Spliethoff 2010)

The power generation industry depends on the available fuel sources and has to apply the best technologies for converting fuel into electric powerin the most economical way as well as the lowest adverse effect on the environment.

Energy production plays an important role in the evolution of societies. However it is considered as one of the major contributors to air pollution. Thermal electric power stations for example, burn large amounts of fossil fuels and produces nitrogen, sulfur and carbon dioxides and other pollutants which cause adverse effects to humans and environment. The average annual growth rate of energy in the world between 2005 and 2030 is expected to be about 2.4% due to the increase in population(Franco and Diaz 2009) .

1.2Power generation overview

Coal, oil and gas are called "fossil fuels" because they have been formed from the organic remains of prehistoric plants and animals. A fossil fuel power plant operates similarly to how nuclear power plants and petroleum power plants work. The difference is the source of heat. The burning of coal replaces fissioning, or splitting, of uranium atoms as the source of heat. There are number of different steps and parts in coal power plant which allow for this process to happen, starting with the burning of the coal (www.duke-energy.com).

Step 1: Coalburningfor Heat

Because the coal cannot be burned in the form that it is naturally in, it is pulverized to the fineness of powder. It is then combined with extremely hot air and blown into the firebox of the boiler. Burning in suspension, means that the coal is not allowed settling while it is in the firebox. It results in the coal-air mixture provides the most complete combustion and maximum heat possible. The exhaust gases are also used to heat the boiler chamber before being released via the chimney stack. This is where the environmental pollutants such as CO_2, NO, SO_2 and ash, Called fly ash, are released into the air.

Step 2: Steam Pressure for Electricity

Highly purified water, pumped through pipes inside the boiler,the heat from the firebox then turns this water into steam. This steam in frequently reaches temperatures of up to 1,000 degrees Fahrenheit, and pressures up to 3,500 pounds per inch, then it is piped to the turbine. The extreme amount of pressure that is created in the boiler is enough to turn the turbine blades that are in the turbine shaft. When these blades are turned, they connect to a generator, where magnets spin within wire coils. This process results in electricity.

Step 3: Condenser Cools the Steam

After the steam causes the turbine blades to turn, and the electricity is produced, the steam is then drawn into a condenser. A condenser is an extremely large chamber that is located in the basement of a power plant. The condenser is an important part of a steam-electric unit, whether nuclear or coal-fired. This device condenses the steam leaving the turbines back into water so that it can be used over and over again in the plant. This essential cooling process requires large quantities of water; therefore, most steam-electric stations are located on lakes or rivers. This significant amount of outside water is pumped through a network of tubes that runs through the condenser. The water that is in these tubes is what cools the steam, and allows the steam to be reconverted into water. After the steam is condensed, it is pumped to the boiler again to repeat the cycle; Figure 1.2 shows a simplified flow diagram for the process (www.duke-energy.com).

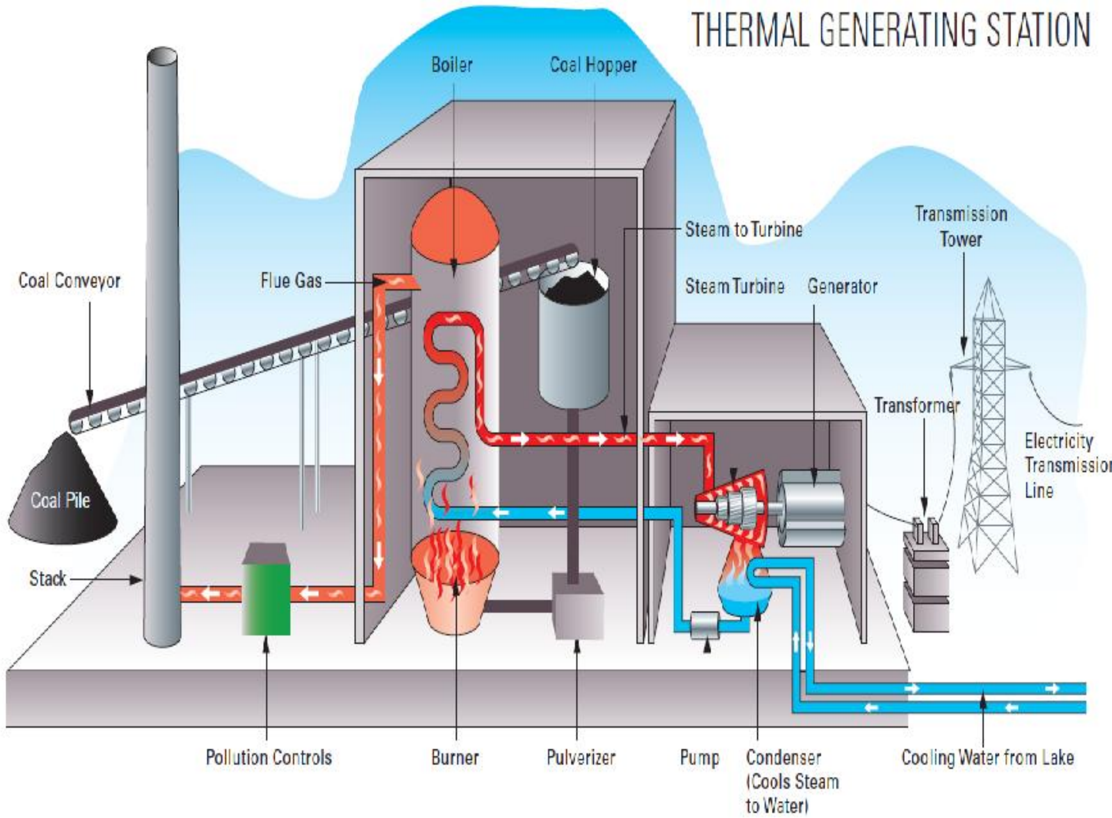

Figure1.2a simplified flow diagram for coal power (www.opg.com)

1.3 Researchcontribution

Recently, controlling air pollutants is an important issue for each country. The power plant sector is considered as one of the key contributing sources to the air pollution problem. NOx and SOx emissions released in the atmosphere by thermal power plant sectors have harmful consequences to human health and to the environmentwhen their concentrations exceed environmental standards.Due to an increased importance on the reduction of these emissions from power generation plants; there has been a significance interest in applying emissions reduction technology to this sector. Therefore, it is essential to develop and implement control options to reduce the emissions of these pollutants from this sector.

1.4Research Objectives

The overall objective of this research is to determine the best strategy or mix of strategies for the electricity sector to meet a given SO_2 or NO_x reduction target at a minimum cost while maintaining a desired production level. A mathematical model will be formulated for the power generation sector to meet the overall objective. The model will be formulated as a MINLP (Mixed Integer Non-linear Program) and implemented in GAMS package. The objectives can be summarized as:

- Developing an optimization model that can be used to determine the best option to reduce NOx and SO_2 emissions for the power generation sector.
- Applying this mathematical model on a real case study from Ontario power generation (OPG), Canada.
- Providing a decision support tool that can be used for production planning with least cost emissions reduction for different reduction target.
- Carrying out a sensitivity analysis because of uncertainty in control costs.

CHAPTER 2

LITERATURE REVIEW

Almost all countries are now considering adopting policies and measures to reduce different air emissions. The power generation sector is considered as one of the major contributors to air pollution. For example, Thermalpower plants consumes a large quantity of fossil fuels every year and produce carbon oxides (CO and CO_2), sulfur oxides (SOx) and nitrogen oxides (NOx)and other pollutants. Some of these pollutants are directly toxic in themselves while others pose indirect health hazards by virtue of their ability to react with other pollutants in the air to form more risky compounds. Therefore, the negative effects of air emissions are their contribution to the formation of acid rain and theiradverse effectsespecially on human health and environment in general. Due to the increase in population, the average annual growth rate of energy in the world between 2005 and 2030 is expected to be about 2.4 %(Franco and Diaz 2009).

Ontario Power Generation (OPG) is one of the main producers of electricity in North America. Currently, it operates 65 hydroelectric, 5 thermal and 3 nuclear stations. As of December 31, 2010 OPG's electricity generating portfolio had a total in-service capacity of 19,931 megawatts (MW). About60% of Ontario's primary electricity demand or 88.6 terawatt hours (TWh) was produced by these generation stations(52% nuclear, 34%

hydroelectric and 14% thermal electricity)(www.opg.com). The thermal power plants emit different air emissions and NOx and SO_2 will be the focus of this study. The following section gives an overview about NOx emission formation.

2.1 Overview of NOx emission formation

NOx is a common term for the various nitrogen oxides produced during burning. These oxides are highly reactive gasses. The most important nitrogen oxides are nitric oxide (NO) which called nitrogen oxide, nitrogen dioxide (NO_2) and dinitrogen monoxide (N_2O) or nitrous oxide.

The main sources of NO_X are motor vehicles and power plants (Figure2.1). Other sources of NO_X are lightening, volcanic activity and oxidation of NH_3. Most of the nitrogen oxides emissions are NO (95% by volume) and NO_2 (5–10% volume)(Chung, Pillai et al. 2009).

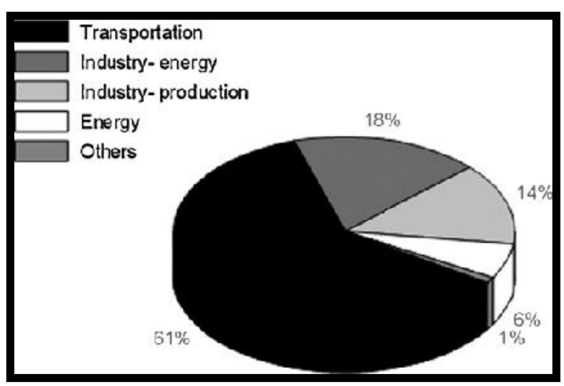

Figure 2.1 Major sources of NOx emission (Chung, Pillai et al. 2009)

These nitrogen oxides react with oxygen in the air to produce ozone, which is an irritant. When dissolved in water and atmospheric moisture, the result is nitric acid and acid rain respectively. Acid rains can cause negative affects to the environment by damaging both trees and entire forest ecosystems and to people and animals through transfer of poisonous substances to the food chain.

Also, NOx react with ammonia, moisture, and other compounds to form small particles. These small particles penetrate deeply into sensitive parts of the lungs and can cause or worsen respiratory disease, such as emphysema and bronchitis, and can aggravate existing heart disease, leading to increased hospital admissions and premature death.

NOx emissions are formed through three main mechanisms during combustion processes(Normann, Andersson et al. 2009):

2.1.1 Thermal NO_Xformation

Thermal $NO_X$is formed through reaction of nitrogen and oxygen present in the combustion air at high temperatures following the mechanism(Gómez-García, Pitchon et al. 2005):

$$N_2 + O^* \rightarrow NO + N^* \qquad (1)$$

$$N^* + O_2 \rightarrow NO + O^* \qquad (2)$$

The planned mechanism involves a chain reaction of O^* and N^* (Eqs. (1) & (2)). It was found that the quantity of NO produced in a combustion process is related to the quantity of O_2 and N_2 in the combustion products and to the heat of combustion, but it is not related to the nature of the fuel. The rate of NO production is given with good accuracy by Zeldovich mechanism as following:

$$\frac{d[NO]}{dt} = 2k[O^*][N_2] \tag{3}$$

Miller and Bowman (1989) suggested a value

$$k = 1.8 \times 10^{11} \exp\left(-\frac{3837}{T}\right) m^3 kmole^{-1} s^{-1} (T\ in\ k).$$

As indicated, the rate of NO formation increases exponentially with temperature and, certainly, oxygen and nitrogen must be available for thermal NO_X formation. Therefore, thermal NO_X formation is rapid in high temperature lean zones of flames. Eqs. (3) Shows that the formation of NO is essentially controlled by reaction (1). It also reveals the importance of both atomic oxygen concentration and temperature.

When exhaust gases are vented to the atmosphere, the conversion of NO to NO_2 occur at low temperature. The following equation represents this reaction:

$$2NO + O_2 \rightarrow 2NO_2 \tag{4}$$

The ratio of NO/NO_2 for nitcogen oxides passing into polluted atmosphere is equal to 10/1, values calculated from rate constants between 400 and 600 k(Gómez-García, Pitchon et al. 2005). However, in the presence of air, the ratio between NO and NO_2could change because of thermodynamic equilibrium.

2.1.2Fuel NO_Xformation

Fuel NO_X arises from the oxidation of nitrogenbound in fuels such as heavy oil, coal, and coke; and its formation reaction can be represented as follows:

$$C(N) \rightarrow I(N) \qquad (5)$$

$$I(N) + O\ (or\ O_2; OH) \rightarrow\ NO + \ldots.. \qquad (6)$$

Where $C(N)$ denotes the nitrogen in char while $I(N)$ represents nitrogen –containing intermediate species like CN, HCN, NH, and NH_2. Fuel bound nitrogen (FBN) is converted to fixed nitrogen compounds such as HCN and NH_3 under reducing conditions surrounding the burning droplet or particle. Sequentially,these are readily oxidized to formNO. Among these reactions, the reduction of NOx over the char surface is quite complex and not yet fully understood(Gómez-García, Pitchon et al. 2005).

2.1.3Prompt NO_Xformation

Prompt NOx is formed immediately during combustion under fuel -rich conditions. therefore, hydrocarbon fragments (such as C, CH, and CH_2) may react with atmospheric nitrogen to yield fixed nitrogen species such as NH, HCN, H_2CN ,and CN as proposed by Fenimore (1972).In sequence, these can be oxidised to NOin the lean zone of the flame.

The prompt mechanism in most flames, particularly those from nitrogen –containing fuels, is responsible for only a small fraction of the total NOx. Its control is important only when attempting to reach the lowest possible emissions.

Habib et al. (2008) studied the influence of combustion parameters on NOx production in boiler. The results have shown that the furnace average temperature and NO concentration decrease as the excess air factor k increases for a given air mass flow rate. However, furnace temperature increases and the thermal NO concentration increase sharply as the combustion air temperature increases. The results also show that NO concentration reveals a minimum value at around swirl angle of 45^0 at the exit of the boiler(Habib, Elshafei et al. 2008).Figure 2.2 shows the three routes of NO_Xformation(Normann, Andersson et al. 2009) .

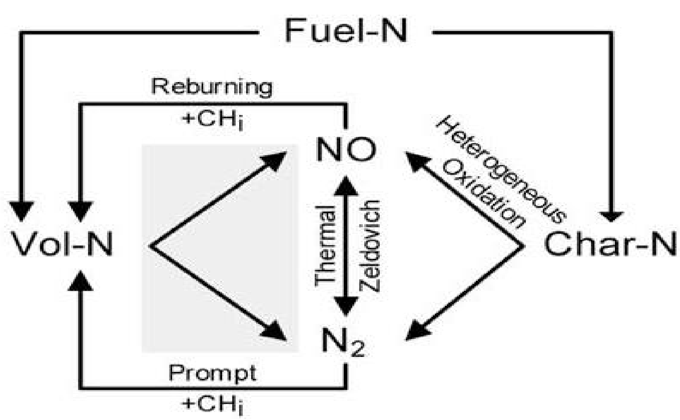

Figure 2.2 Overall mechanisms of NO formation and reduction (Normann, Andersson et al. 2009)

2.2NOxcontrol technologies

Several technologies have been developed to reduce the emission of NO_X from power generation plants. NO_X reduction technologies are generally divided into two principle methods: primary and secondary methods. Primary methods are techniques applied during combustion by modifying the operational conditions to reduce the NOx formation this technique called combustion modifications. Flue gas treatments are the secondary methods which can occur both within the boiler and at several points along the path of the flue gas from the boiler to the stack.

2.2.1Combustion modifications

Combustion modifications considered as the most common, commercially available technologies of controlling NO_X emissions from power plants. The basic concept of these techniques is reduction of NO_X formation by effecting moderately simple modifications of operating conditions or by incorporating more elaborate modifications of the combustion facility.Generally Combustion modifications were classified into five categories(Someshwar 2003):

- Low excess air (LEA)
- Staged combustion
- Temperature reduction technologies
- Low NO_X burners (LNB)
- In-furnace destruction (reburning)

- ***Low excess air (LEA)***

Moderate reductions NO_X emissions may be occur by reducing the amount of excess air, and consequently excess oxygen, in the local flame zone. Lower NO_Xemissions and higher boiler efficiencies results when operating the burners with low excess air (less than 5% for oil and gas fired boilers). However, the drawbacks of this technique are the limitation by the production of smoke, high CO emissions and increase fouling and corrosion problems in the boiler(Someshwar 2003). The feasible reduction of NO_X by LEA is believed to reach up to 15 %(Ontario 2002).

- ***Staged combustion***

Staged combustion or off-stoichiometric combustion considered as one of the oldest modification techniques for NO_Xreduction. The main idea of this technique is to divert a small portion of the combustion air through separate ports located above the burners creates a fuel rich zone. Staged combustion can be carried out by different in- furnace techniques such as: a) Overfire air (OFA) b) Burners out of service (BOOS) c) Biased burner firing (BBF)(Someshwar 2003).

- ***Temperature reduction technologies***

Reducing peak flame temperatures to minimize thermal NOx formation is the main concept of these technologies. These techniques include:

a) Flue gas recirculation (FGR)
b) Reduced air preheated

c) Steam and water injection

d) Decreased load

- ***Low NOx and Ultra Low NOx Burners (LNB & ULNB)***

Low NOx burners (LNBs) are designed to control the air and fuel mixing to create low NOx conditions such as reduced oxygen concentrations available in the initial combustion zone by minimizing the excess air, reduced maximum flame temperatures by reducing intensity of mixing.LNB uses both staged air and staged fuel combustion principles. (Staged air LNBs are simple, inexpensive and efficient NOx controls that are frequently specified for both new and existing boilers and incinerators).Combustion adjustment with LNBs is used in both coal-fired and gas/oil-fired units. About 50% NOx reduction is expected by a full LNB retrofit (Someshwar 2003).Ultra low-NOx burners (ULNB) are second generation LNBs that achieve even greater NOx reductions (70 – 75%)(Ontario 2002). In comparison to LNBs which use staged fuel to reduce NOx, ULNBs reduce NOx by inducing the internal circulation of fuel gas within the heater (Someshwar 2003).

- ***In-furnace destruction (Reburning)***

In this technique which also known as “fuel staging”, a reburn fuel typically supplies from 15 to 25% of the total fuel input .This amount is injected to a second combustion zone downstream of the main flame. Intermediate combustion products in the fuel-rich secondary zone react with NO formed in the primary zone to produce N_2.The reburn zone is followed by additional combustion air to fully burn the remaining hydrocarbons and CO. In this technology, in order to minimize further NOx formation, Low nitrogen-

containing fuels such as natural gas and distillate oil are typically used for this purpose(Someshwar 2003). NOx emissions can be reduced by reburning up to 60 %, with operating cost depends on the cost of natural gas. High levels of unburnt carbon in ash may be produced when other fuels such as biomass and coal are used possibly as
reburn fuel(Chambers 2001).

2.2.2Flue gas treatment

Flue gas treatments are the secondary methods which can occur both within the boiler and downstream of the combustion process. These techniques are preferred for NO_X control because they provide wider range for utility system loads than possible by combustion modifications. This approach involves destroying NO_X or allowing NO_X to react with other reagents. NO and NO_2 are unstable thermodymically(Gómez-García, Pitchon et al. 2005).

$$NO \leftrightarrow \frac{1}{2}N_2 + \frac{1}{2}O_2 \ (\Delta G^0 = -86 kJ \ mol^{-1}) \quad (7)$$

$$NO_2 \leftrightarrow \frac{1}{2}N_2 + O_2 \ (\Delta G^0 = -51 kJ \ mol^{-1}) \quad (8)$$

Decomposition reaction of NO has high activation energy (~335 kJ mol^{-1}). Therefore, a catalyst is required to facilitate decomposition reaction(Gómez-García, Pitchon et al. 2005).These technologies include selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR).

- ***Selective non-catalytic reduction (SNCR)***

Selective non-catalytic reduction (SNCR) is an “add-on control” using a reducing agent, typically ammoniaanhydrous, ammoniahydroxide, urea (Eq.9), or aqueous ammonia .These compounds when injected into the combustion products from 900 to 1100 ^{o}C will react with NOx to covert it back to N_2 and H_2O(Chambers 2001).

$$CO(NH_2)_2 + 2\,NO + \frac{1}{2}O_2 \rightarrow 2\ N_2 + CO_2 + 2H_20 \qquad (9)$$

Although the advantages of not requiring a catalyst and its lower installation cost, this technique does not offer NO_xremoval levels better than modern low NO_xburners. Because of this, it is used in regions or equipment where there is no need for a high NO_x removal efficiency. The performance of urea or NH_3 –based SNCR systems is affected directly by six factors. These are: a) inlet NO_xlevel, b) residence time, c) temperature, d) mixing, e) reagent to NOx, and f) fuel sulfur content. The optimal temperature window, wherean obvious NO_x reduction is achieved, is between 900 and 1,100 °C depending on thecomposition of the flue gas. Above this desired window temperature ammonia is oxidized to anincreasing extent, i.e. NO_x are formed. At lower temperatures the reaction rate is slowed down, causing unreacted ammonia reagent (ammonia slip) which mayresult in the formation of ammonia salts in the further flue gas path and may lead to secondaryproblems(Someshwar 2003). In general the reduction of NO_x in this technology is between 30% and 75% (Ontario 2002).This technique is attractive due to its simplicity, catalyst –free system, inexpensive to install, applicability to all types of stationary-fired equipments and lower capital and operating cost. The schematic of the SNCR concept iselaborated in Figure 2.3.

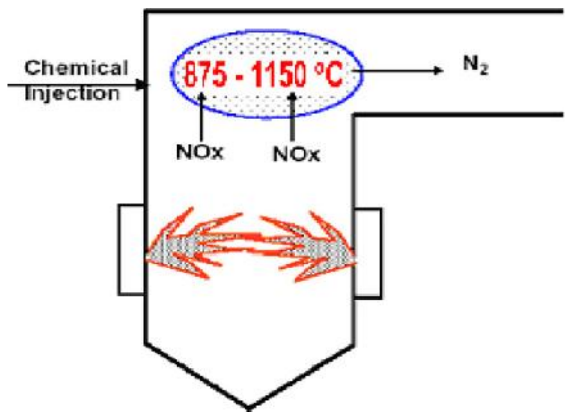

Figure 2.3 The schematic of the SNCR concept (Tayyeb Javed, Irfan et al. 2007)

- ***Selective catalytic reduction (SCR)***

The SCR process has been used commercially in Japan, Germany, and in the U.S. since 1980, 1986, and the 90's respectively. This technology is also uses ammonia injection. The essential operating principle of a selective catalytic reduction unit is the reduction of theNO_Xcontent of exhaust gases by ammonia (NH_3) as it passes over a catalytic material at reaction temperatures between 300 to 400 ^oC.The following selective overall reactions arecarried out on the catalytic surface(Someshwar 2003):

$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$ (10)

$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$(11)

The reduction of NO_X by ammonia is promoted by the SCR catalyst to produce N_2. The main types of catalyst are (Gómez-García, Pitchon et al. 2005):

(a) Supported noble metal catalysts, e.g., Pd/Al_2O_3.

(b) Base metal oxide catalysts, e.g., those containing vanadium.

(c) Metal ion exchanged zeolites, e.g., Cu-ZSM-5.

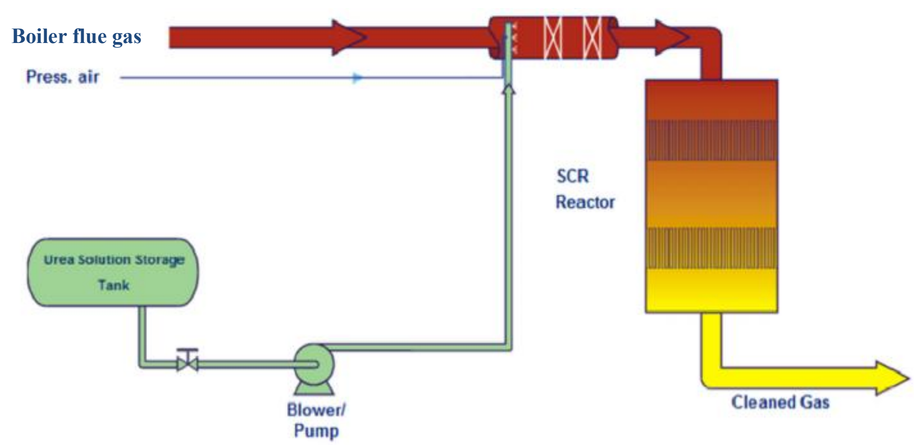

Figure 2.4 The schematic of the SCR concept(Burström, Lundström et al. 2010)

NOx control efficiencies are typically in therange of 70 to 90%, depending on the type of catalyst, amount of NH_3 injected, the initial NO level, and the age of the catalyst.

Several studies have been conducted that address the control of NOx emissions from the power generation sector.Miroslav (1998) compared between SCR and SNCR and indicate that NO_X reduction performance of SCR is 70-90% while 30-80% for SNCR.The operating temperature in case of SNCR is higher (800^0C -1100 ^{0}C) compare to SCR (200^0C -500^0C). Ammonia slip in SNCR is between 0.8 -2.5 ppm and 0.4 -1ppm for SCR(Miroslav 1998).

McCahey et al. (1999) have investigated the impact of NOx reduction technologies upon a supercritical coal power station using the ECLIPSE process simulator .The study applied conceptually to the Amer 9 power station at Geertruidenberg, the Netherlands, which is a 600 MW supercritical Pulverized coal fired power station with low NOx burners. The technical, environmental and economic evaluations have been performed using the ECLIPSE process simulator. In conclusion, all of the technologies investigated provide considerable reductions in NOx emissions. The coal-over-coal and natural gas-over-coal reburn systems both produced approximately 50% less NOx than the base case, however the SCR post combustion method showed the most substantial change, producing a 90% reduction but at an additional electricity cost of 0.21 p/kWh, over the base case(McCahey, McMullan et al. 1999).

Gotham et al. (2001)have studied the impact of various nitrogen oxides (NOx) emission control scenarios on the price of electricity for the state of Indiana. The scenarios represent different methods for reducing NOx emissions levels to 0.15 or 0.25 lb/mmBtu. The analyses were performed using a traditional regulation forecasting model that equilibrates between price and demand. The proposed plans used in the development of these scenarios include the use of Low NOx burners, flue gas recirculation, steam or water injection, and staged combustion. Post-combustion control is done using either catalytic or non-catalytic reduction(Gotham, Holland et al. 2001).

Alnatheer (2006) presented a study to evaluate the environmental impacts of electric system in Saudi Arabia. This study introduced the major environmental costs ranges that are associated with expansion of Saudi Arabia's electric supply system. He considered the importance of Externalities because energy resources impose a variety of costs on society when evaluating alternative plans, so his analysis showed that significant environmental benefits for the Kingdom can be provided by using of renewable energy and energy efficiency resources to provide energy services to the electricity consumers of Saudi Arabia(Alnatheer 2006).

Wang et al. (2007) investigated the feasibility of the application of flameless oxidation (FLOX) and continuous staged air combustion (COSTAIR) technologies to control the combustion temperature and the reaction rate and consequently to control the NOx emissions. They used ECLIPSE simulation software with two different fuels – coal and biomass (straw) for both FLOX and COSTAIR technologies which are assessed based on a 12MWe, coal-fired, circulating fluidized bed combustion (CFBC) power plant, together with a circulating fluidized bed gasification (CFBG) plus normal burner plant. The result of their study showed that 90% of NOx emission reduced by using the application of FLOX technology to the plant and are reduced by 80-85 % using the COSTAIR technology , and with less plant efficiencies(Wang, McIlveen-Wright et al. 2007).

Evangelos Tzimas et al. (2007) studied the impact of capture of carbon dioxide (CO_2) from fossil fuel power plants on the emissions of acid gas pollutants which are nitrogen oxides (NO_X) and sulfur oxides (SO_X). This work has been done by estimating the difference in the quantities of acid gas pollutants (NO_X and SO_X) and CO_2 emitted by fossil fuel fired power plants with and without CO_2 capture. In this study, two power generation options are investigated: natural gas combined cycle plants (NGCC) and pulverized coal (PC) plants. They concluded that the capture of CO_2 is not possible to increase the acid gas pollutants quantities from a power generation plant. In contrast, some NO_X and SO_X will be removed by the low selectivity of the solvents used to capture the CO_2 from the flue gases(Tzimas, Mercier et al. 2007).

Chung et al. (2009) investigated the development of a mediated electrochemical oxidation (MEO) process-based wet scrubbing method for NO and NO_2 abatement from a simulated NO air flue gas mixture using Ag(II)/Ag(I)-mediated electrochemical oxidation. 100% removal of NO and 80% NOx removal were achieved from simulated NO-air flue gas mixture in a single stage gas scrubbing operation. The overall removal of NOx was improved to 90% using combination with a second stage gas scrubbing by a simple HNO_3 wash(Chung, Pillai et al. 2009).

Carlinet al. (2009) has studiedthe potential emission and economic savings from reburning coal with cattle biomass and compares those savings against competing technologies. The profitability of a CB reburning system retrofit on an existing coal-fired plant improved with higher coal prices and higher valued NOx emission credits. The CB reburn option was the most expensive at Year 1 under base case assumptions. SCR was also found to have the highest capital cost. SNCR was found to have the cheapest capital investment cost, but the emission levels achieved by SNCR were assumed to be poorer than levels achieved by either CB reburning or SCR(Carlin, Annamalai et al. 2009).

Franco et al. (2009) summarized the various NO_X control options with their limit level using coal as fuel. It is noted that the use of LNB with OFA and SCR gives the highest NO_X reduction efficiency (85-95%) while the use of LNB with OFA and LNB with SCR gives the efficiency of 40-60% and 50 -80 % respectively(Franco and Diaz 2009).

Neuffer has studied the NOx emission levels and cost of various control technologies for 200 MW units operating in the eight Northeast states (USA). It is found that control efficiency range for LNB and/or OFA is 15%-60%. Cost per ton of NOx removed is in the range of $200-1,000. NOx reduction using Natural gas reburning (NGR) for Coal-firing boilers is between 45 and 65% while cost effectiveness per ton of NOx removed is under $800/ton when applied to high NOx emitting cyclone units. For coal fired utility boilers, SNCR can achieve similar emission reductions at slightly higher cost effectiveness as combustion modifications ($590-1300/ton). SCR can achieve 80 % NOx reductions from uncontrolled boilers at cost effectiveness of $1700-5000/ton. However due to limited full scale experience, the cost estimates for SNCR and SCR have a high degree of uncertainty(Neuffer).

Combustion modification controls for oil/gas fired utility boilers have been used since the early 1970s primarily in California. Estimated emission levels for these controls are 0.1 to 0.35 lb/MMBtu or a NOx reduction of 15%-80%. The cost effectiveness varies from $100 to $5100/ton. SNCR is estimated to achieve a 35 % to 50 %NOx reduction at a cost effectiveness of $670-2200/ton. SCR is estimated to achieve 65%-85% reduction at cost effectiveness of $2600-7400/ton(Neuffer).

2.3 Overview of SOx emission formation

Sulfur oxides (SOx) are classified as a pollutant because they react with water droplets in the atmosphere to produce sulfuric acid. These acidic pollution compounds return to the earth (lakes, rivers, and soil) in the form of acid deposition, which is the major component in acid rain. The acid is extremelycorrosive and harmful to the environment. The combustion of fossil fuels (coal and oil) and the smelting of mineral ores that contain sulfur results in pollutantsoccurring in the form of SO_2 (sulfur dioxide) and SO_3 (sulfur trioxide), together referred to as SOx (sulfuroxides). The level of SOx emitted depends directly on the sulfur content of the fuel(Siudek 2009).In this work , we will be referring for SOx as SO_2 only.

2.4 SO_2 control technologies

There are a variety of removal technologies that have been reported in the literature for controlling SO_2 emissions in the power plants. Four major technology strategies for SO_2emissions control have been tracked by the power generation industry(Ba-Shammakh 2011):

1. Tall gas stacks that disperse emissions away from immediate areas;
2. Intermittent controls, which involve routine operational adjustments to reduce power plant SO_2 emissions in response to atmospheric conditions;
3. Precombustion reduction of sulfur from fuels; and
4. Removal of SO_2 from the post-combustion gas stream.

The post-combustion process is the currently accepted means to remove SO_2 after the combustion of fossil fuels as well as fuel switching to lower-sulfur-content fuel.Thesecontrol technologies, known as flue gas desulfurization (FGD). FGD has been in commercial use in different forms since 1970's. Over the last decade, FGD technique has made considerable progress in terms of efficiency, costs and reliability as SO_2 emission regulations have become more strict in worldwide(Takeshita 1993).Generally FGD can be categorized as :

- Wet scrubbers;
- Spray dry scrubbers;
- Sorbent injection processes;
- Regenerable processes;
- Combined SO_2 /NO_X removal processes.

- ***Wet scrubbing***

The most common FGD process to reduce SO_2 emission is wet scrubbing. In this technique, the sulfur containing exhaust gases are absorbed with hydrated lime or limestone in a counter- flow reactor and the sulfate is oxidized to gypsum by-product. Wet scrubbers produce a large amount of solid waste that must be disposed of by landfill. Wet scrubbers currently occupy 87% of the FGD market due to their potential to produce a gypsum byproduct and the potential to remove up to 99% of the SO_2(Chambers 2001).

- ***Spray dry scrubbing***

Spray dryers (semi-dry FGD),have the next largest considerable share of the FGD in the market .With the operation of spray dry scrubbers ,a lime water slurry is injected into the flue gas to remove SO_2 and as a result calcium sulphite/sulphate is formed. These solid materials are removed along with the flyash in a baghouse. The removal of SO_2 by this technique is reach to 95%(Chambers 2001).Spray dry scrubbers have low operating cost and does not need waste water treatment. However, the ratio of sorbent to SO_2 must be approximately 2.0 for achieving greater than 95% SO_2 removal (Xu, Chen et al. 2000).

- ***Sorbent injection processes***

In these technologies, powdered limestone injected into the combustion products within a temperature window of 750 to 1250 ^{o}C.The limestone converts to calcium oxide (CaO) and reacts with sulfur dioxide (SO_2) to form calcium sulphate ($CaSO_4$).Sorbent injection processes are relatively inexpensive .However, it is appropriate for only about 50% SO_2 reduction at Ca/S mole ratio of 2:1.For low sulfur coal, SO_2 reduction efficiency will be less due to the lower concentration of SO_2 initially in the combustion products(Chambers 2001).Sorbent injection processes can be sub-divided into the categorizes of spray chamber, simple bubbler, spray tower and packed tower.

Several papers have been published to find the best solution to reduce SO_2 emissions from the power generation sector. William (1995)gavean overview of the various technologies available forthe control of SO_2emission in coal power production as well as a broad overview of SO_2 emission regulation. Thelogistics and trends in worldwide supply and use of different available steam coal resources are reviewed in relation to the need for limiting and reduction in sulfurousemissions(William 1995).

Harmelen et al. (2002) used the energy model TIMER, to introduce add-on abatement technologies, specified in terms of costs and reduction potentials, in order to be able to calculate cost-effective emission reduction strategies for different scenarios and regions in Europe. The results show that add-on technologies to reduce regional air pollution remain necessary throughout the century. The costs to reach the NOx emission reduction targets in Europe are about three times as high as for SO_2.Mitigation costs averaged over the century by add-on technologies can be reduced by climate measures by 50–70% for SO_2 and around 50% for NOx. The costs of SO_2 and NOx mitigation by add-on technology in a world without climate policy are comparable or in some periods even higher than the costs of an integrated mitigation of SO_2, NOx and CO_2 emissions if a reduction of specific costs by learning is, in contrast with energy technologies, not assumed for abatement technologies. So, the costs of SO_2 and NOx add-on measures avoided by climate policies can outweigh the costs of these climate measures. The total annual costs are in the order of 1 or 2% of the present GDP, depending on the scenario(Van Harmelen, Bakker et al. 2002).

Patsias et al. (2005) studied the performance of a suite of different carboxylic salts of calcium as dual NOx/SOx reducing agents. The salts studied include, calcium magnesium acetate (CMA), calcium acetate (CA), calcium formate (CF), calcium benzoate (CB), calcium propionate (CP) and magnesium acetate (MA). Their Experiments were performed in a down-fired pulverized coal furnace operating at an output of 80 kWth. Results showed that CMA and CP were the best dual NOx/SO_2 performers followed by CB, CA, MA and CF. CMA and CP showed superior SO_2 capture ability with reductions greater than 70% at Ca/S above 2, around 20% higher than calcium acetate and calcium formate(Patsias, Nimmo et al. 2005).

Wang et al.(2007) proposed a process capable of removing NOx, SO_2 and mercury simultaneously which utilizes the injection of ozone and assist with a glassmade alkaline washing tower as shown in Figure (2.5) . Results showed that NO and Hg oxidation efficiency improved individually with the increasing amounts of ozone added to the main flow. About 97% of NO and nearly 100% of SO_2 can be removed simultaneously with 360 ppm of ozone addedwith the assistance of washing tower as shown in Figure (2.6)(Wang, Zhou et al. 2007).

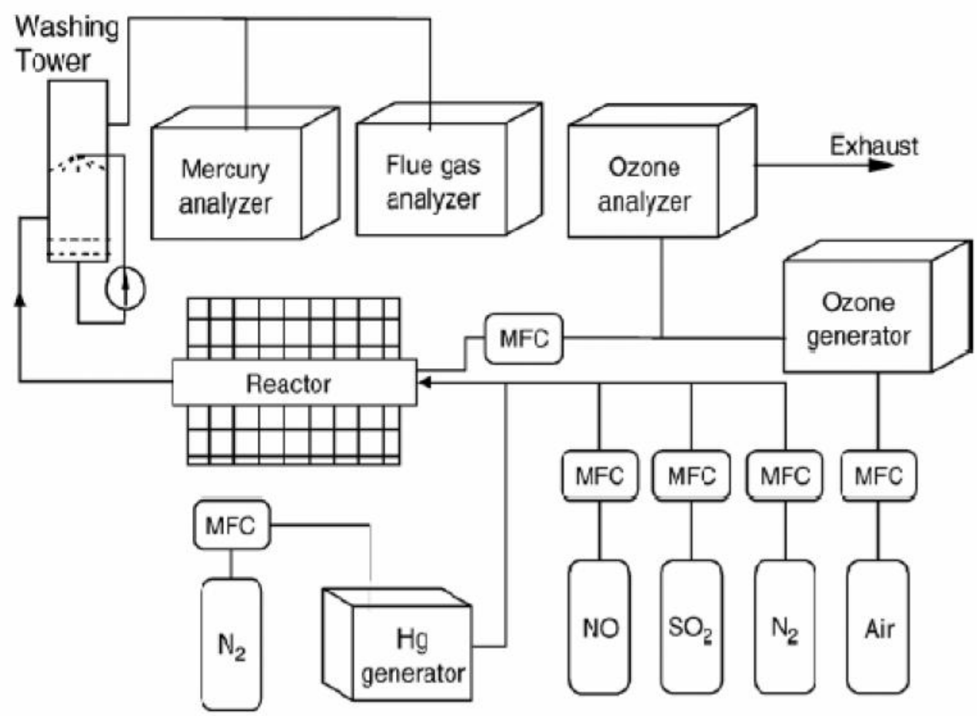

Figure 2.5the schematic diagram of the experimental apparatus including the ozone injection technology (Wang, Zhou et al. 2007)

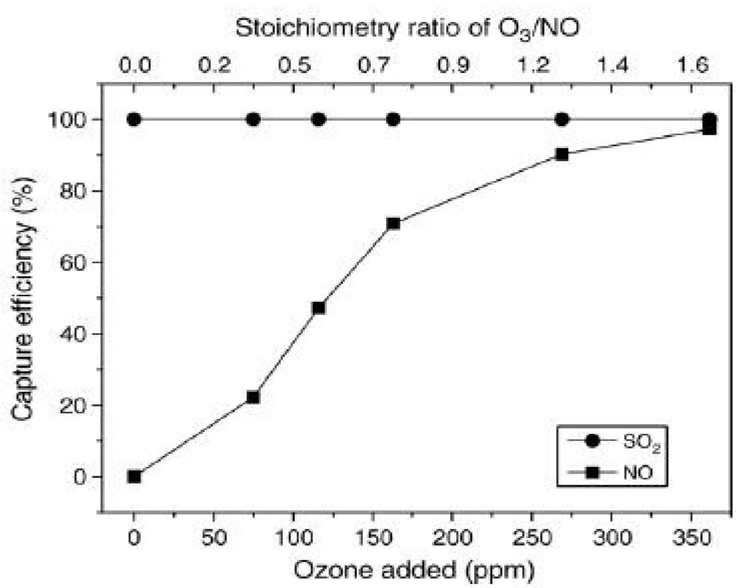

Figure 2.6 Simultaneous capture efficiency of NO, SO_2 behind the washing tower with ozone injection T=423 K(Wang, Zhou et al. 2007)

Mohanty et al. (2008) designedand fabricateda multi-stage fluidized bed reactorwhich was employed for sorption of sulfur dioxide on the CaO to remove SO_2. They found that the removal of acid gas was enhanced due to the high mass transfer and high gas–solid residence time using the multi-stage fluidized bed reactor at low temperature. The results have indicated that the removal efficiency of the sulfur dioxide was found to be 65% at high solid flow rate (2.0 kg/h) corresponding to lower gas velocity (0.265 m/s), weir height of 70mm and SO_2 concentration of 500ppm at room temperature(Mohanty, Adapala et al. 2009).

2.5 Mathematical Modeling in power generation

Several papers have been published which addressed the cost effectiveness of air emissions control strategies in power generation using mathematical programming approach.Mavrotas etal.(1999) developed a multiple objective mixed integer linear programming (MOLP) model applied to the Greek power sector for identifying the number of and the productivity of each of power units required to satisfy the predictable electricity demand in the future(Mavrotas, Diakoulaki et al. 1999).

Linares and Romero (2000) developed a methodology applied to an electricity planning scenario in Spain with a planning horizon set for the year 2030. The model included the following objectives: (1) total cost; (2) CO_2; (3) SO_2; and (4) NO_x emissions as well as the amount of radioactive waste produced(Linares and Romero 2000).

Yokoyama et al.(2002) formulated a MILP (mixed integer linear programming model) for the structural design problem to determine an optimal structure of energy supply system to match energy demand condition, by expressing load allocation of equipment and capacities by continuous variables, andthe selection and on/off status of operation of equipment by binary variables. The effect of equipment performance characteristics on their capacities as well as capital cost, were integrated into the optimization model. The objective was to minimize annual capital cost, and was evaluated as the sum of the annualized capital and operational costs of energy purchased(Yokoyama, Hasegawa et al. 2002).

Zhou, Huang et al. developed ES-APC as an expert support system to assist decision-makers in coal power plants in selecting an efficient and cost effective pollution control system that meets new strict emission standards. A fuzzy relation model and a Gaussian dispersion model were integrated into the expert system. This study provided the key design parameters of ES-APC which provides users with the most cost effective control strategy given complex and uncertain specifications. The result of this study showed that the developed system can help the power plant reduce capital and operation costs of pollution control and decrease risks of environmental damage by selecting suitable control technology(Zhou, Huang et al. 2004).

Zhou et al. (2004) developed a model to predict NOx emission characteristics of a tangentially fired boiler under various operating conditions and burning different coal using artificial neural networks (ANN) technology(Zhou, Cen et al. 2004).

Hashim et al. (2005)formulated the problem of reducing CO_2 emissions from a fleet of generating stations consisting of coal, natural gas, nuclear, hydroelectric, and renewable energy as a mixed integer linear program (MILP) and implemented in GAMS. Two carbon dioxide mitigation options were considered in their study: fuel balancing and fuel switching(Hashim, Douglas et al. 2005).

Habib et al. (2008) investigated the problem of NOx emission numerically using a model furnace of an industrial boiler utilizing fuel gas. The studied boiler is 160 MW, gas fired with natural gas, water tube boiler, having two vertically aligned burners. The results have shown that the increase in the excess air factor λ for a given air mass flow rate leads to decrease in the furnace average temperature and NO concentration. Also, the result showed that increasing λ results in a maximum value of thermal NO concentration at the exit of the boiler at $\lambda = 1.2$. Also, furnace temperature increases and the thermal NO concentration increases sharply as the combustion air temperature increases(Habib, Elshafei et al. 2008).

Ba-Shammakh et al. (2007) formulated a mixed integer non-linear programming (MINLP) model for CO_2 reduction from power generation and the model was applied to Ontario power generation (OPG)(Ba-Shammakh, Elkamel et al. 2007).

In (2009), nine types of energy generation options were evaluated using the Analytic Hierarchy Process (AHP) methodology by Pilavachi et al.With regard to seven criteria. The options use natural gas or hydrogen as a fuel. The criteria used for the evaluation are efficiency, NO_Xemissions, CO_2 emissions, capital cost, maintenance and operation costs, and service life and produced electricity cost. Among 19 scenarios were studied, they proved that the hydrogen combustion turbine, which ranked in 15 of these scenarios is the most dominant electricity generation technology. They expect that the cost of the hydrogen turbine's generated electricity to be very competitive in the future(Pilavachi, Stephanidis et al. 2009).

Chang Zheng et al. (2009) developed a comparative study to reduce NOx emissions from a coal – fired utility boiler by using various optimization algorithms. The result indicated that NOx emissions Can be effectively reduced of the coal-fired utility boiler below the legislation requirement of China by the hybrid algorithm by combining support vector regression (SVR) and optimization algorithms with the exception of particle swarm optimization (PSO)(Zheng, Zhou et al. 2009).

Liu et al. (2009) applied an energy technology model, MESSAGE, to analyze the options of key new power generation technologies and their contributions to GHG mitigation in China. Based on this analysis, they expect that in the short term, traditional renewable technologies (including hydropower and wind power), high- efficiency coal power generation technologies and nuclear power will contribute significantly to GHG mitigation while in the middle- and long-term, solar power, biomass energy and carbon capture storage (CCS) will play the main roles in GHG mitigation(Liu, Shi et al. 2009).

Ba-Shammakh (2011) Formulateda multi-periodmixed integer non-linear programming (MINLP) model for integrating planning and SO_2 mitigation in the power generation sector and the model was applied to Ontario power generation(Ba-Shammakh 2011).

CHAPTER 3

RESEARCH METHODOLOGIES

In this chapter,superstructure representation for the energy supply system from different types of power stations is described in details. Also in this chapter, a general optimization model for the power generationis developed. The model consists of anobjective function and a set of constrains. The objective of the model is to minimize the electricity cost and at the same time reduce NOx and SO_2 emissions at minimal cost with respect to different reduction targets.

3.1Superstructure representation

The power generation supply system from multipletypes of power stations is represented in asuperstructure manner as shown in Figure (3.1). Electricity is generated from different types of power plants and directly injects it into the grid. It is assumed that only the thermal power plants (fossil fuel plants) generate air emissions and there are no control processes on any existing power stations.

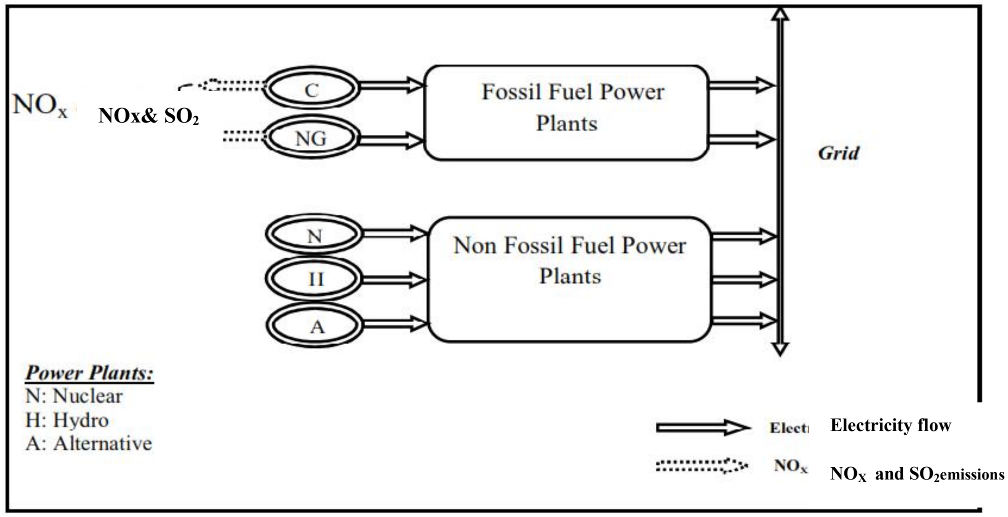

Figure 3.1 Superstructure for power plants

Three different options to reduce SO_2 and NOx emissions are also considered in this superstructurerepresentation and these are:

1. Fuel balancing.
2. Fuel switching
3. Appling technology.

3.1.1 Fuel balancing superstructure

Fuel balancing option is the optimal adjustment of the generating stations operations to reduce SO_2 and NOx emissions without making structural changes to the fleet. The target here is to determine the optimal productionfor each power plant in order to maintain electricity to the grid and reduce the emissions simultaneously. Figure (3.2) shows the fuel balancingwhere NOx and SO_2emissions are decreased by increasing the power production of existing non-thermal plants and decreasing the power production of existing thermal power plants.

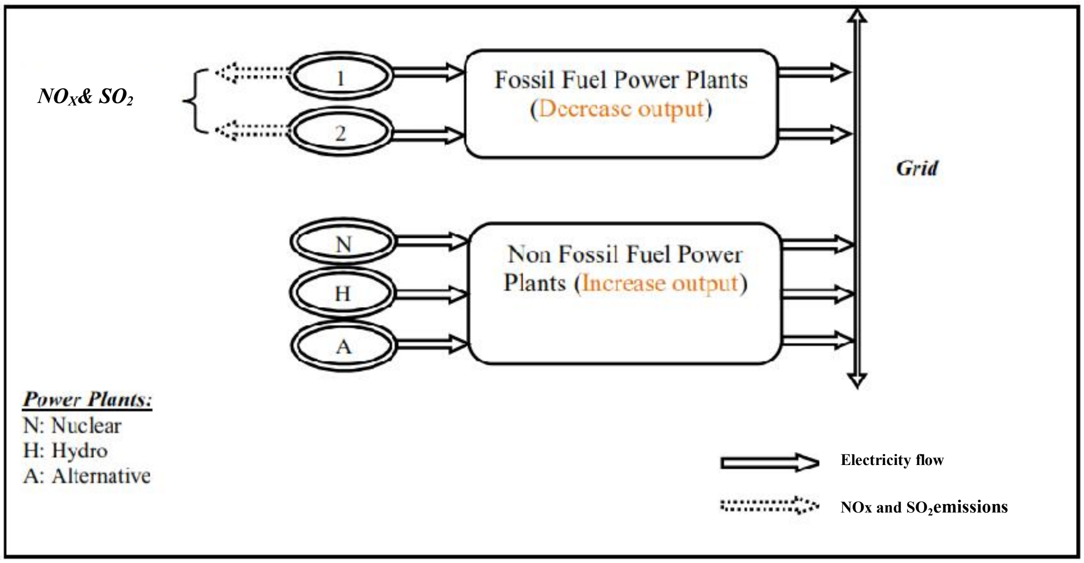

Figure 3.2 Fuel balancing

3.1.2 Fuel switching superstructure

Fuel switching option is the switching fromthe fuel used in a particular power plant to fuel that emits less SO_2 or NOx emissions and involves structural changes to the fleet as shown in Figure (3.3).

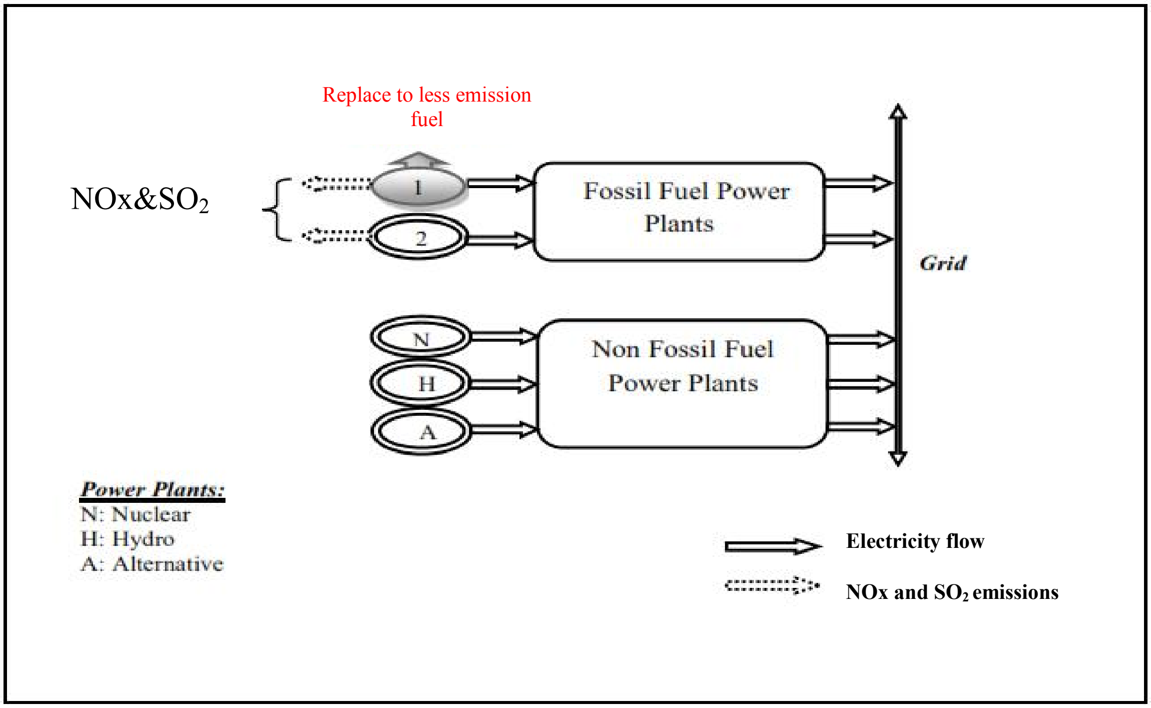

Figure 3.3 Fuel switching

3.1.3 Control technology implementation superstructure

Technology control superstructure shows the integration of possible technologies that can be implemented in power plants to decreaseSO_2 or NOx emissions while maintaining the same electricity to the grid as illustrated in Figure (3.4).

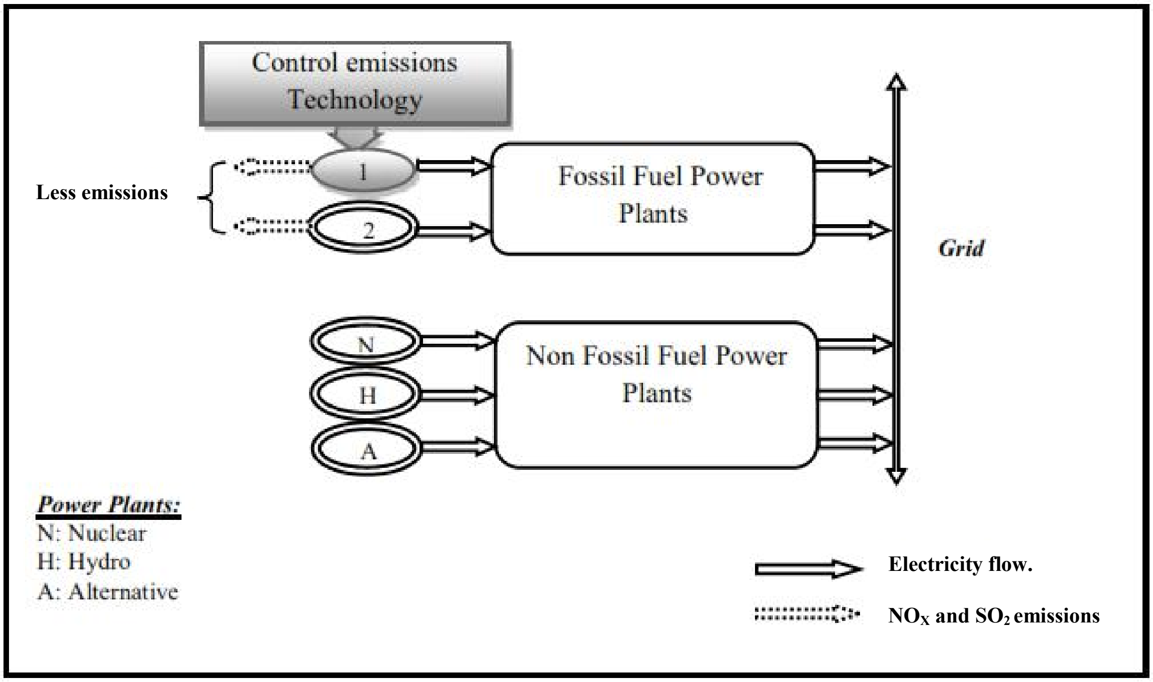

Figure 3.4 Control technologies

3.2 Model formulation

This section describes the mathematical approach. The model is formulated as an optimization problem. Itis written in a general format that consists of an objective function to be minimized and a set of constrains which needs to be satisfied at the solution. The objective function (COE) is to minimize the total annualized cost of electricity generated and in mathematical format, it can be written as:

$$\text{Min COE} = \underbrace{\sum_{P \in F} \sum_{u} (FC)_{Pu} (EG)_{Pu}}_{\substack{\text{Fixed cost of electricity generation} \\ \text{from fossil fuel power plants}}} + \underbrace{\sum_{P \in F} \sum_{u} (OC)_{Pu} (EG)_{Pu}}_{\substack{\text{Operating cost of electricity generation} \\ \text{from fossil fuel power plants}}} + \underbrace{\sum_{P \in NF} (FC_{NF})_P (EG)_P}_{\substack{\text{Fixed cost of electricity generation} \\ \text{from non-fossil fuel power plants}}} +$$

$$\underbrace{\sum_{P \in NF} (OC_{NF})_P (EG)_P}_{\substack{\text{Operating cost of electricity generation} \\ \text{from non-fossil fuel power plants}}} + \underbrace{\sum_{P \in F} \sum_{u} (RC)_{Pu} X_{Pu}}_{\substack{\text{Retrofit cost for switching} \\ \text{from coal to natural gas}}} + \underbrace{\sum_{P \in F} \sum_{T} (FC)_{PT} Y_{PT}}_{\text{Fixed cost of applying technology}} + \underbrace{\sum_{P \in F} \sum_{T} (OC)_{PT} Y_{PT}}_{\text{Operating cost of applying technology}}$$

(1)

Where:

COE: Cost of electricity

P: Power plant

F: Fossil fuel power plants include coal and natural gas.

NF: Non- Fossil fuel power plants.

u: Type of fuel (coal or natural gas).

T: Technology applied to the plant.

$(FC)_{Pu}$: Fixed cost of electricity generation if fuel *u* used on fossil power plant *P*($/MWh).

$(OC)_{Pu}$: Operating cost of electricity generation if fuel *u* used on fossil power plant *P*($/MWh).

$(EG)_{Pu}$: Electricity generated from *P*th power plant if fuel *u* is used (MWh/yr).

$(FC_{NF})_P$: Fixed cost of electricity generation from *P*th Non-fossil fuel power plants ($/ MWh).

$(OC_{NF})_P$: Operating cost of electricity generation from *P*th Non-fossil fuel power plants ($/ MWh).

$(EG)_P$: Electricity generated from *P*th Non-fossil fuel power plants (MWh/yr).

$(RC)_{Pu}$: Retrofit cost to switch from coal to natural gas ($/yr).

X_{Pu} : Binary variable either to switch plant *P* to natural gas or not.

Y_{PT} : Binary variable either to apply technology ***T*** in plant *P* or not.

$(FC)_{PT}$: Fixed cost to apply technology$\boldsymbol{T}$ in plant *P (*$/yr).

$(OC)_{PT}$: Operating cost to apply technology $\boldsymbol{T}$ in plant *P (*$/yr).

The first and the second terms in the above equation represent the fixed and operating cost of electricity generation from fossil fuel power plants respectively whereas the third and fourth terms explain the fixed and operating cost of electricity generation from non-fossil fuel power plants. Then, a term for switching isincluded with a binary variable X, which is set to be 0 if noswitching, is carried out and 1 in the case of switching from coal to natural gas.The last two terms represent the fixed and operating cost associated with applying technologieson fossil fuel power plants for emissions reduction.

Constraints:

The generalmodel consists of the following sets of constraints:

- ***Power demand***

The total electricity generated from allfossil-fuel and non-fossil-fuel power stations must be equal to or greater than the demand (*Dm*).

In mathematical format, it can be written as:

$$\sum_{P\epsilon F}\sum_{u}(EG)_{Pu} + \sum_{P\epsilon NF}(EG)_{P} + \sum_{P\epsilon I}(EG)_{I} \geq Dm \tag{2}$$

- ***Fuel selection or plant shut down*:**

For each fossil fuel power plant*p*, the plant either operates with a given fuel or is shut down. For this reason, a binary variable is introduced to represent the type of fuel used in a given fossil fuel plant. X_{Pu} =*1*if fuel u is used in plant p otherwise it is 0.

$$\sum_{u} X_{Pu} \leq 1 \qquad \forall\, P \epsilon\, F \qquad (3)$$

- ***Upper bound on operational changes***

The adjusted electricity generated from each fossil and non-fossil fuel power plant should be less than or equal to a maximum capacity.

$$(EG)_{Pu} \leq (EG)_{Pu}^{MAX} X_{Pu} \qquad \forall\, P \epsilon\, F \qquad (4)$$

$$(EG)_{P} \leq (EG)_{P}^{MAX} \qquad \forall\, P \epsilon\, NF \qquad (5)$$

This constraint set requires that the electricity produced from any plant *p*should not exceed the maximum capacity of the plant. The first constraint is for fossil-fuel power plants, while the second is for non-fossil-fuel power plants. A binary variable is introduced in each constraint to represent its existence (or nonexistence).

- ***Lower bound on operational changes***

These constraints introduce a lower bound for each power plant. The electricity generated from each power plant must be greater than some minimum otherwise the plant will be shut downanda binary variable is introduced in each constraint to represent that.

$$(EG)_{Pu} \geq (EG)_{\mathrm{Pu}}^{MIN} X_{Pu} \qquad \forall P \epsilon F \qquad (6)$$

$$(EG)_{P} \geq (EG)_{P}^{MIN} \qquad \forall P \epsilon NF \qquad (7)$$

- ***Technology selection***

A binary variable (Y_{PT}) is introduced in the model to represent whether technology***T*** implemented in power plant*p* or not.This constraint imposes the factthat no technology should be implemented in a plant that is to be switchedfrom high emission fuel to less emission fuel.

$$\sum_{T} Y_{PT} + NK \times X_{Pu} \leq NK \qquad \forall P \epsilon F \qquad (8)$$

Where***NK***is number of set of technologies*T*.Furthermore, only one control technology can be installed for agiven power plant *P*:

$$\sum_{T} Y_{PT} \leq 1 \qquad \forall P \epsilon F \qquad (9)$$

- ***Emissions constraint***

The total emissions from electricity generation must satisfy a reduction target and it should be equal to or less than a certain limit. Different technologies, $\boldsymbol{T}$, to control emissions will be implemented in the mathematical model and a binary variable $(\boldsymbol{Y_{PT}})$will be introduced to represent existence or not of a certain technology for emissions control.

$$\sum_{P\epsilon F}\sum_{u}(EM)_{Pu}\,.\,(\eta).\,(EG)_{Pu}\ \leq (EM)_{current} \quad (10)$$

Where

$$\eta = \left(1 - \ \sum_{T} \varepsilon_{PT} Y_{PT}\right)$$

Where$\boldsymbol{\varepsilon_{PT}}$ **:** efficiency of applying technology *T* to power plant *P*.

- ***Non-negativity constraints***

The electricity produced from all power plants must be greater than zero.

$$(EG)_{Pu}\ \geq 0 \quad and \quad (EG)_{P}\ \geq 0 \qquad (11)$$

The resulting model is formulated as a MINLP because of a constraint set where there isa multiplication of a decision variable $(EG)_{Pu}$ and a binary variable (Y_{PT}) in the emissions term.

The general form of a MINLP is

Minimize f(EG,x, y)

Subjectto h(EG,x, y) =0

g (EG,x, y) ≥0

EG E≤R^n(EG is a vector of continuous variables)

xX = {0,1} (x is a vector of binary variables)

y Y = {0,1}(y is a vector of binary variables)

The model has been linearised and proved to have the same optimum asthe original one. Therefore, we solved the model as mixed integer linear programming (MILP).

It was implemented in GAMS (Generalized Algebraic Modeling System).It is usually employed as the environment to solve such problems. GAMS, originally developed by the World Bank for large scale economic modeling, is a flexible system that is ideal for developing large scale problems.The solver used is CPLEX.

- ***Model linearization***

The emission constraint (10) is the one that causes non-linearity to the optimization model. The nonlinear term is:

$$\sum_{P \epsilon F} \sum_{u} (EM)_{Pu}(\eta)(EG)_{Pu} \text{ (1A)}$$

Where

$$\eta = \left(1 - \sum_{T} \varepsilon_{PT} Y_{PT}\right)$$

Hence, the non-linearity is due to the product $\left[Y_{PT}(EG)_{Pu}\right]$

Let $\gamma_{PuT} = Y_{PT}(EG)_{Pu}$ (non-linear term) (2A)

The term can be linearized by adding these constraints to the model:

$0 \leq \gamma_{PuT} \leq (EG)_{Pu}$ (3A)

$$(EG)_{Pu} - (EG)_{Pu}^{MAX}(1 - Y_{PT}) \leq \gamma_{PuT} \leq (EG)_{Pu}^{MAX} Y_{PT} \qquad \text{(4A)}$$

Where $(EG)_{Pu}^{MAX}$ is a maximum upper bound on $(EG)_{Pu}$.

We can proof that as following:

From equation (2A), we want to show that $\gamma_{PuT} = 0$ if $Y_{PT} = 0$

and $\gamma_{PuT} = (EG)_{Pu}$ if $Y_{PT} = 1$

<u>Case 1</u>: (<u>*No technology is selected*</u>)

<u>$Y_{PT} = 0$</u>

Since $\gamma_{PuT} = Y_{PT}(EG)_{Pu}$ (from eqn 2A),

Then, $\gamma_{PuT} = 0$

Equation (3A) becomes:

$0 \leq \gamma_{PuT} \leq (EG)_{Pu}$ (5A)

And equation (4A) becomes:

$(EG)_{Pu} - (EG)_{Pu}^{MAX} \leq \gamma_{PuT} \leq 0$ (6A)

From equations (5A) and (6A), γ_{PuT} will be chosen to be zero.

<u>Case 2</u>: (<u>*technology is selected*</u>)

<u>$Y_{PT} = 1$</u>

Since $\gamma_{PuT} = Y_{PT}(EG)_{Pu}$ (from equation 2A),

Then, $\gamma_{PuT} = (EG)_{Pu}$

Equation (3A) becomes:

$0 \le \gamma_{PuT} \le (EG)_{Pu}$ (7A)

And equation (4A) becomes:

$(EG)_{Pu} \le \gamma_{PuT} \le (EG)_{Pu}^{MAX}$ (8A)

From equations (7A) and (8A), γ_{PuT} is set equal to $(EG)_{Pu}$ .In summary, adding the two constraints (equation 3A and 4A) to the model will lead to:

$\gamma_{PuT} = 0$ if $Y_{PT} = 0$

and $\gamma_{PuT} = (EG)_{Pu}$ if $Y_{PT} = 1$

3.3 Emissions estimation from Combustion

This section gives a general procedure for the estimation of NOxand $SO_2$from fuel combustion.

Fuel combustion that emits NOxand SO_2emissions depend upon the amount of fuel consumed and the carbon content of the fuel. To estimate emissions from fuel combustion, the following equation has been adopted.

$$\text{Emissions}(\text{NOx or } SO_2) = \text{Fuel consumption} \times \text{EF}$$

EF is emission factor for a specific fuel. These factors have been obtained and developed from a number of studies conducted by Environment Canada, the United States Environmental Protection Agency (EPA) and other organizations.

CHAPTER 4

RESULTS AND DISCUSSIONS

The general mathematical model developed in Chapter three for power generationwas illustrated on different case studies.This modelwas applied into real case studies taken from Ontario Power Generation (OPG)to find the best strategy to reduce certain air emissions at minimum cost while maintaining electricity demand.Three different mitigation options are considered and these are:

1) Fuel balancing (optimal adjustment of the operation of existing generating stations to reduce air emissions without making structural changes to the fleet).

2) Fuel switching (switching from fuel that emits more emissions to less emissions fuel).

3) Implementing different technologies to reduce airemissions.

Currently, Ontario Power Generation (OPG) operates five thermal power plants:Four of these stations are fuelled by coal and one is dual-fuelled by oil and natural gas, 65 hydroelectric,3 nuclear and 2wind power turbines.As December 31, 2011, OPG had an in-service capacity of 19,051 MW.There are 13 fossil fuel boilers at the 5 fossil fuel stations: 2 boilers at Lambton (LMB), 4 boilers at Nanticoke (NTK1–NTK4), 1 boiler at Atikokan (ATK), 4 boilers at Lennox(LNX1–LNX4), and 2 boilers at Thunder Bay (THB1–THB2). Currently, the 4 boilers at Lennoxare running on natural gas. Figure 4.1 shows the existing OPG fossil fuel power plants (13 boilers) and their associatedelectricity generated.

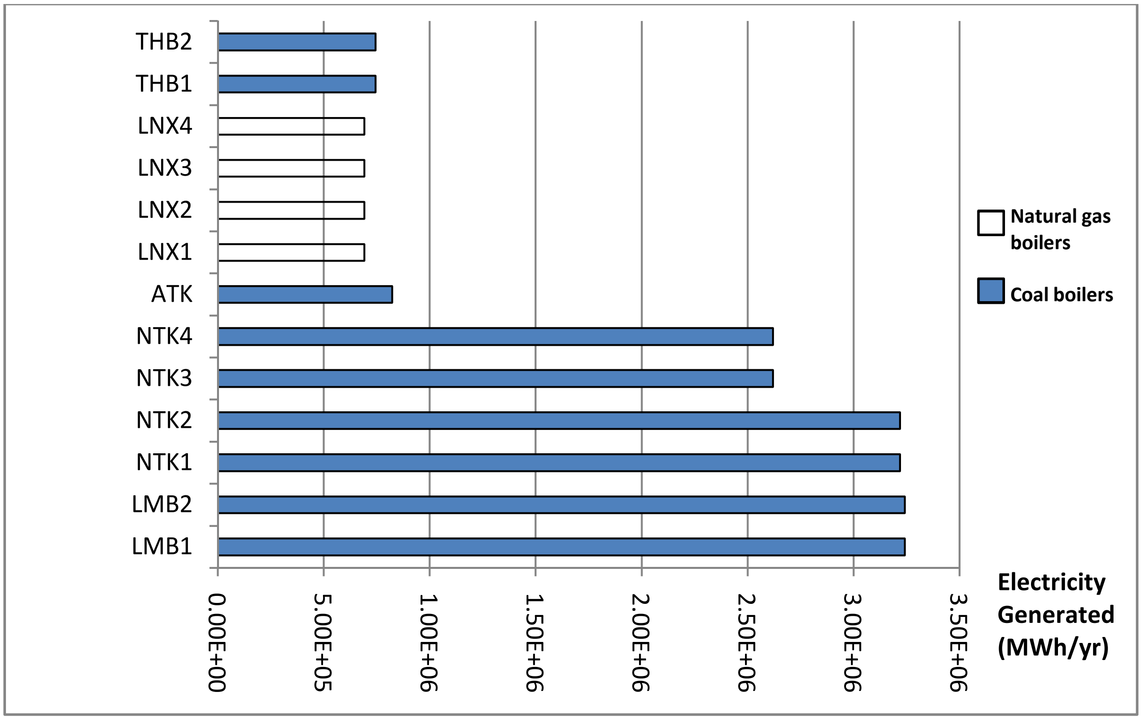

Figure 4.1 Electricity generated from OPG power plants (13 boilers)

This research focuses on two air emissions that are considered significant for power generation sector. These are namely NOx and SO_2.

Two case studies (1 and 2) are illustrated in the following sections: case study (1) considersNOx emission for Ontario power generation and case study (2) which was run independently from the previous case considers SO_2 emission for the same sector.

4.1Case study 1

In this case study, NOx emission will be considered for Ontario power generation.The objective of this study is to determine the best strategy or mix of strategies for the electricity sector to meet a given NOx reduction target at a minimum cost while maintaining adesired production level.Table 4.1 shows a general view of OPG fossil fuel generatingstations and NOx emission. Since non fossil fuel power plants are assumed not to emit NOx, the main focus is on electricity generated from the fossil fuel power plants.The operational costs fornuclear, hydroelectric, and wind turbine were estimated to be \$43.2, \$6.75, and \$5.4/MWh,respectively. The nominal conditionsfor OPG's existing fleet of power plants are:

- Total electricity generation: 11884 MW
- Total NOx emissions: 37346 ton/yr
- Total operational cost: 3.086×10^9 \$/yr.

Table 4.1 OPG fossil fuel generating stations and NOx emission(Atten 2004)

Generating stations	*Fuel used*	*Installed capacity (MW)*	*Number of Units*	*Operational cost (\$/MWh)*	*NOx emission rate (ton/MWh)*	*Current electricity generated (MWh/yr)*
Nanticoke 1(NTK1)	Coal	500	2	40	0.00172	3219300
Nanticoke 2 (NTK2)	Coal	500	2	40	0.00172	2619567

Lambton (LMB)	Coal	500	2	34	0.00147	3242295
Lennox (LNX)	Natural gas	535	4	81	0.00109	690500
Thunder Bay (THB)	Coal	155	2	40	0.0021	745000
Atikokan (ATK)	Coal	215	1	40	0.00193	823000

NOx emissions were calculated based on emission factors taken from North American Power Plant Air Emissions report(Atten 2004).Three mitigation options to reduce NOx emission considered here are fuel balancing, fuel switchingand applying different technologies to control NOx emission for coal power plants. Three technologies are considered in this case study which are: Low NOx burners (LNB) with about 35% efficiency, selective non-catalytic reduction (SNCR) with about 50% efficiency and selective catalytic reduction (SCR) with about 85% efficiency. The costs effectiveness of these technologies as reported in the literature are: $1200, $1550 and $2000 /ton of NOx removed respectively. The cost for each technology is amortized with a 10-year lifetime and a 5%annual interest.

The power generation supply system from different types of power stations is represented in a superstructure manner as shown in Figure 4.2.Three different options to reduce NOx emissions are also considered in this superstructurerepresentation as shown in Figures 4.3, 4.4 and 4.5 which are fuel balancing, fuel switching and applying LNB, SNCRor, SCR technologies.

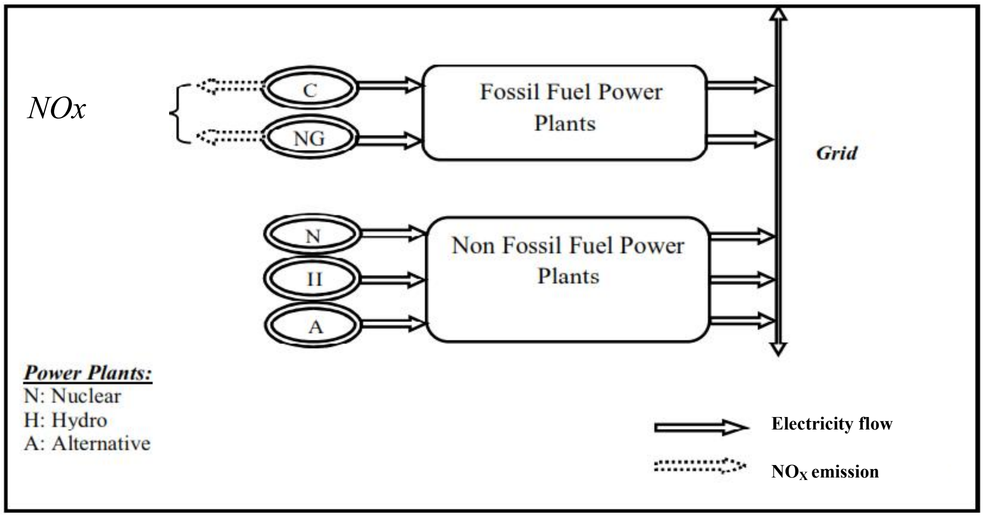

Figure 4.2 Superstructure for power plants

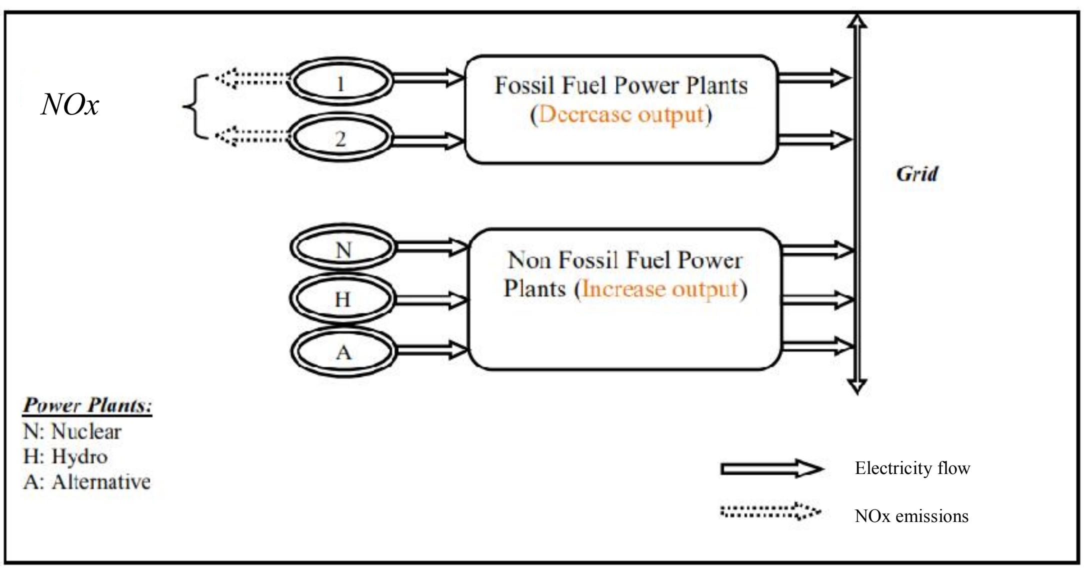

Figure 4.3 Fuel balancing

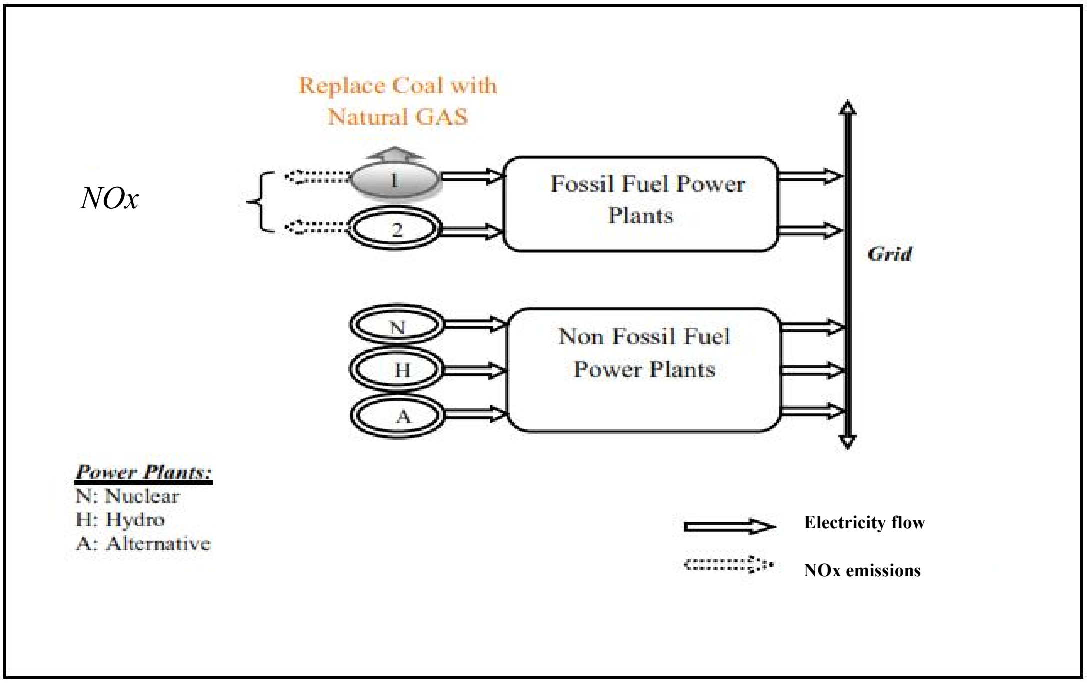

Figure 4.4 Fuel switching

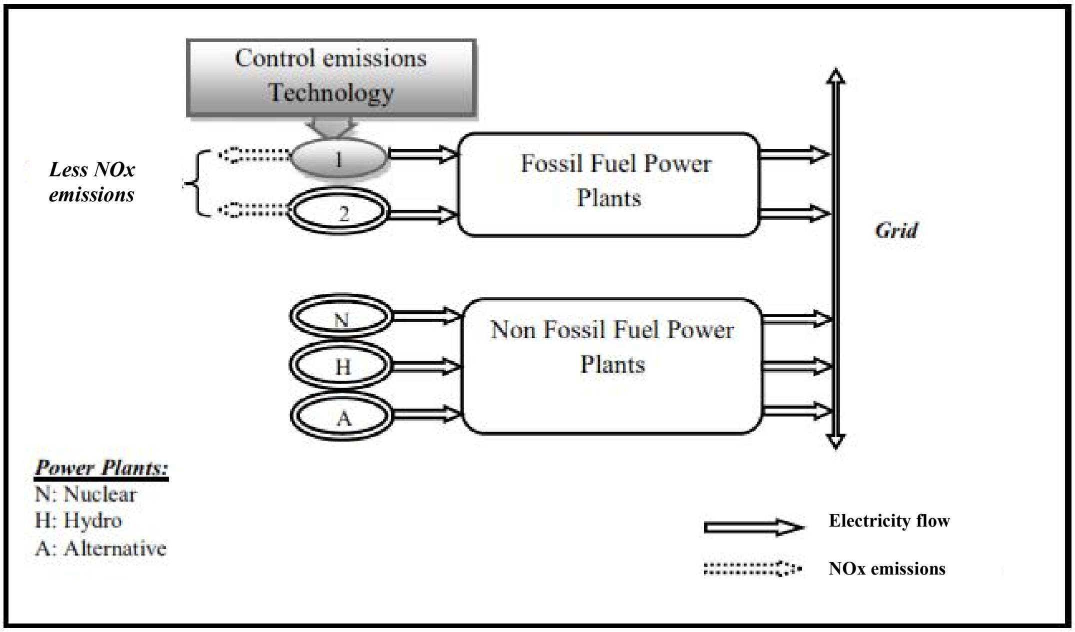

Figure 4.5 control technologies

The initial model was MINLP and then it is being normalized. The linearised model discussed earlier in chapter 3 was coded into the General Algebraic Modeling System (GAMS) and solved using the mixed integer linear programming (MILP)solver. Two cases were studied in this case study; case (1.A) will consider two options which are fuel balancing and switching. For case (1.B), all three options will be considered.

4.1.1Case 1.A

The options considered in this case for the NO_X reduction are balancing and fuel switching only.

The optimization result for the base case (0% NOx reduction) showsthat all non fossil fuel power plants have to operate with 1% (maximum allowable value) higher than the nominal capacity factor. The only plant for which the capacity factor decreases is the

Lennox generating station (natural gas) in which the capacity factor decreased by about 32%. This result may appear to be expectedsince the Lennox stations is fuelled by natural gas. However, the reason why the productivity of Lennox must be decreased is because this plant uses the most expensive fuel in OPG's fleet. The reduction in NOx emissions is achieved by increasing slightly the power production of the non-thermalpower plants (hydro-electric, nuclear and wind) and by decreasing significantly the power production of Lennox. The productivity of the other fossil fuel plants was increased by only a small increment.The overall effect of the adjustments in the capacity factors is to reduce the overall NOx emissions.The model tries to satisfy demand of each station by adjusting the operation of existing boilers e.g., increasing productivity from existing non thermalpower plants and decreasing productivity from some existing thermal power plants (fuel balancing) as shown in Figure 4.6.Base case is also shown in the Figure for comparison.

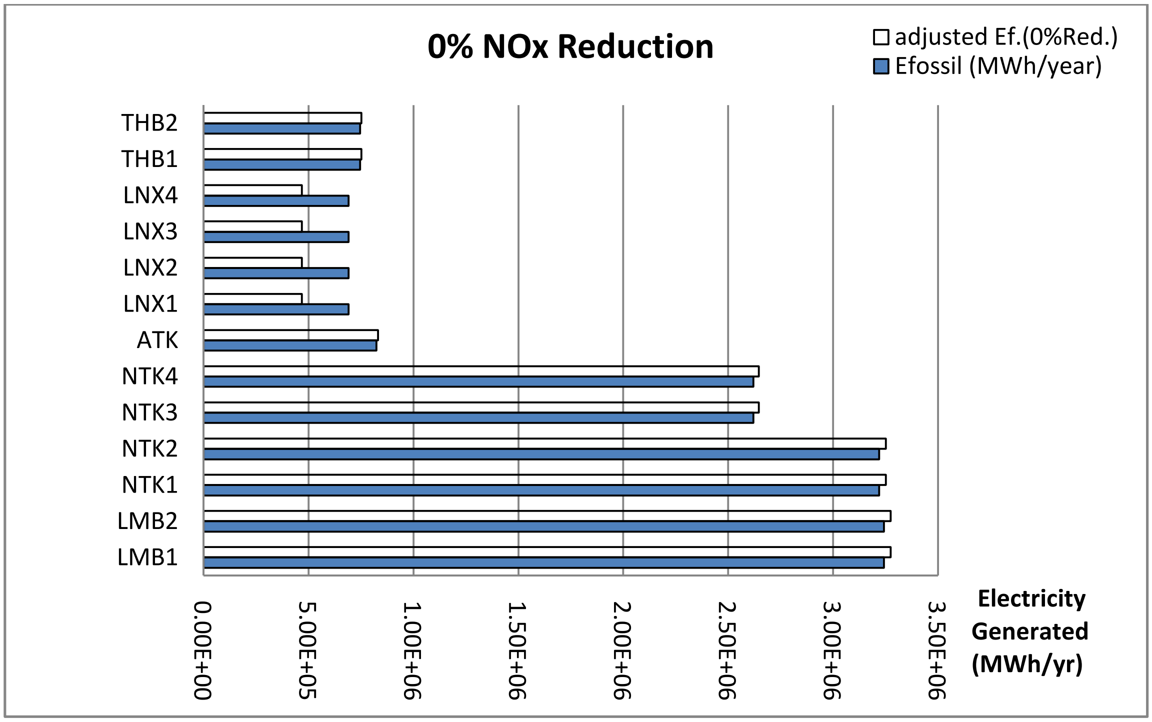

Figure 4.6 Electricity generation strategy for 0% NOx reduction

Figure 4.7 shows the optimization results for the case of 5% NOx reduction target.For this case, we noticed that the model chose to switch one unit (THB1) from coal to natural gas. The results show that the capacity factors for three of the natural gas boilers (LNX1, LNX2 and LNX4) have beenreduced by 32% and one coal fired boiler (THB2) by 45%.

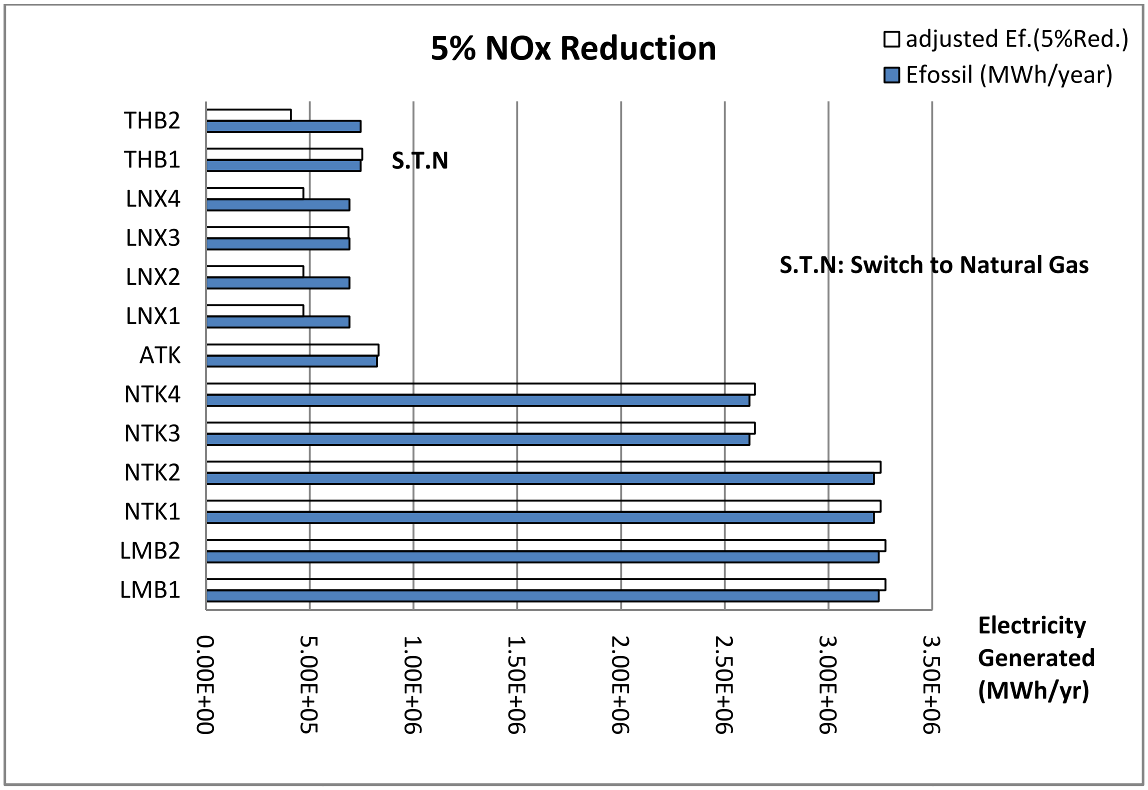

Figure 4.7 Electricity generation strategy for 5% NOx reduction

In order to achieve more than 5% NOx reduction, the model chose to switch more than one unit. This involves fleet changes from coal to natural gas. As seen inFigure 4.8, for example, the optimization results show that in order to achieve a 10% NOx reductionwhile maintaining the electricity to the grid at minimum cost, the power production forall natural gas boilers have beenreduced by 32%,and one boiler at Nanticoke (NTK4), two boilers at Thunder Bay (THB1and THB2)need to be switched from coal to natural gas. The capacity factors for the non-fossilfuel generating stations should be increased by 1% which is always the case.

In addition to switching of one boiler at Nanticoke (NTK4) from coal to natural gas, the results also showed that thecapacity factor of this power plant should bedecreased by about 4%.

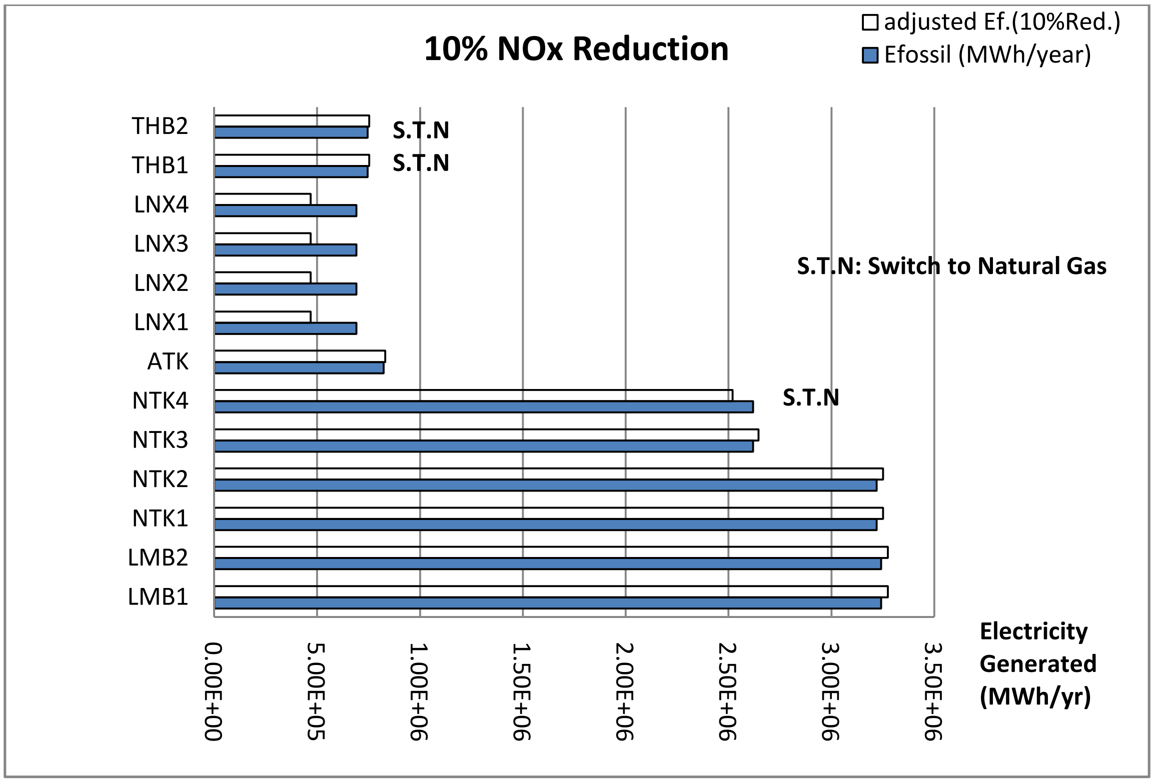

Figure 4.8 Electricity generation strategy for 10% NOx reduction

As higher NOx targets are required, the optimizer will choose more coal boilers to be switched to natural gas.For the case of 30% NOxreduction(see Figure 4.9), the results show that all boilers which are running by coal need to be switched to natural gas except one boiler at Lambton (LMB2).The result also shows that the capacity factor forall natural gas boilers at Lennox power plant havebeenreduced by about 32%,and alsothe same thing is truefor Atikokan power plant (ATK) by about 14%.The electricity generationfrom all non fossil fuel power plants has also been increased by 1%.

We noticed that if we go beyond 30% NOx reduction, switching will not be a good option and we have to implement another option to reach to a higher reduction target.

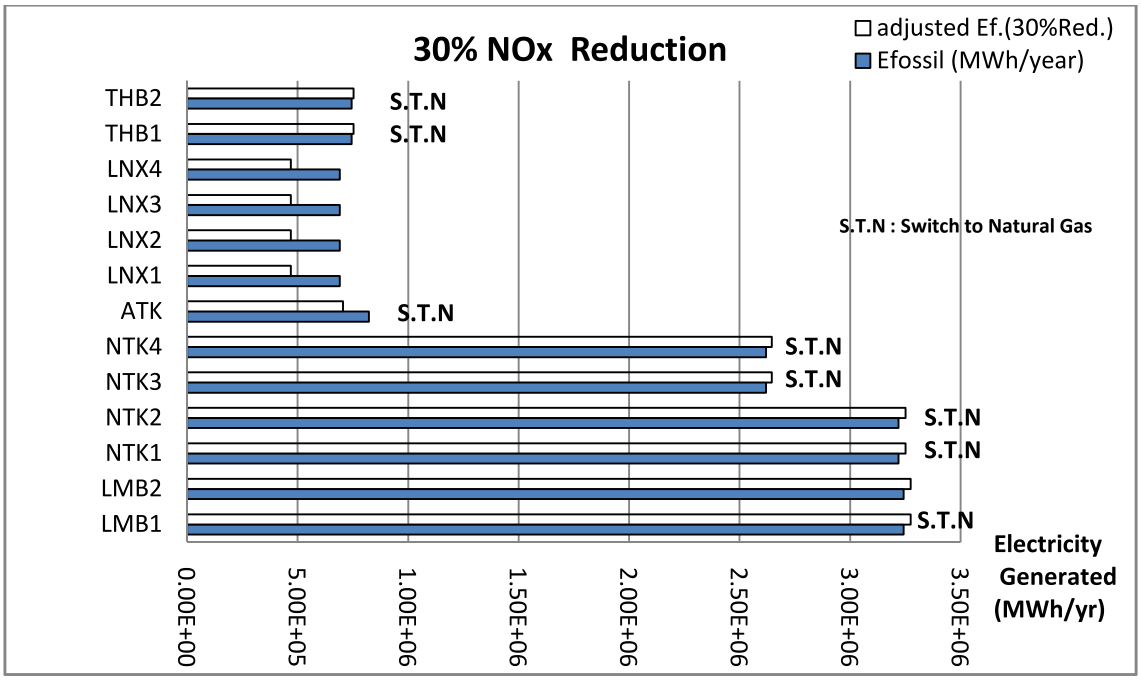

Figure 4.9 Electricity generation strategy for 30% NOx reduction

Table 4.2 below summarizes the results for case (1.A).It shows that whetherthe units (boilers) in the plants needs to be switched to natural gas or not for different reduction targets.The full black squares represent coalunits while open circles represent natural gas units. However, the multiplication sign represents the switching option.

Table 4.2 A summary of the optimization results for case **1.A**

Plant	*Base case*	*0% NOx Reduction*	*5% NOx Reduction*	*10% NOx Reduction*	*30% NOx Reduction*
LMB1	▪	▪	▪	▪	×
LMB2	▪	▪	▪	▪	▪
NTK1	▪	▪	▪	▪	×
NTK2	▪	▪	▪	▪	×
NTK3	▪	▪	▪	▪	×
NTK4	▪	▪	▪	×	×
ATK	▪	▪	▪	▪	×
LNX1	○	○	○	○	○
LNX2	○	○	○	○	○
LNX3	○	○	○	○	○
LNX4	○	○	○	○	○
THB1	▪	▪	×	×	×
THB2	▪	▪	▪	×	×

▪ : Coal

○ : Natural Gas

× : Switch to Natural gas

Table 4.3shows the total cost and NOx emission for each reduction target. It is clear that increasing thetarget of NOx reduction will give ahighertotal annualized cost since it involves fleet changes from coal to natural gas (switching).

Table 4.3 Total cost and total NOx emission at different reduction targets for case 1.A

% NOx Reduction	***Total cost ($/yr)***	***total NOx emission (ton/yr)***	***cost increased %***
0	3.04E+09	36722.152	
5	3.06E+09	35478.719	0.78
10	3.12E+09	33400.556	2.58
30	3.37E+09	25700.332	10.96

4.1.2 Case 1.B

All three mitigation options to reduce NO_X emission are considered here which arebalancing, fuel switching and implementing different technologies.

The same optimization results in case 1.A for 0%NOx reduction when two mitigation options (fuel balancing and fuel switching) considered were obtained here for the case of 0% NOx reduction when all threemitigation options considered. The results show that all non fossil fuel power plants have to operate with 1% higher than the nominal capacity factor. The only plant for which the capacity factor decreases is the Lennox generating station (natural gas) in which the capacity factor decreased by about 32%.The model tries to satisfy demand of each station by adjusting the operation of existing boilers e.g., increasing production from existing non thermalpower plants and decreasing production from some existing thermal power plants (fuel balancing) as shown in Figure 4.10.

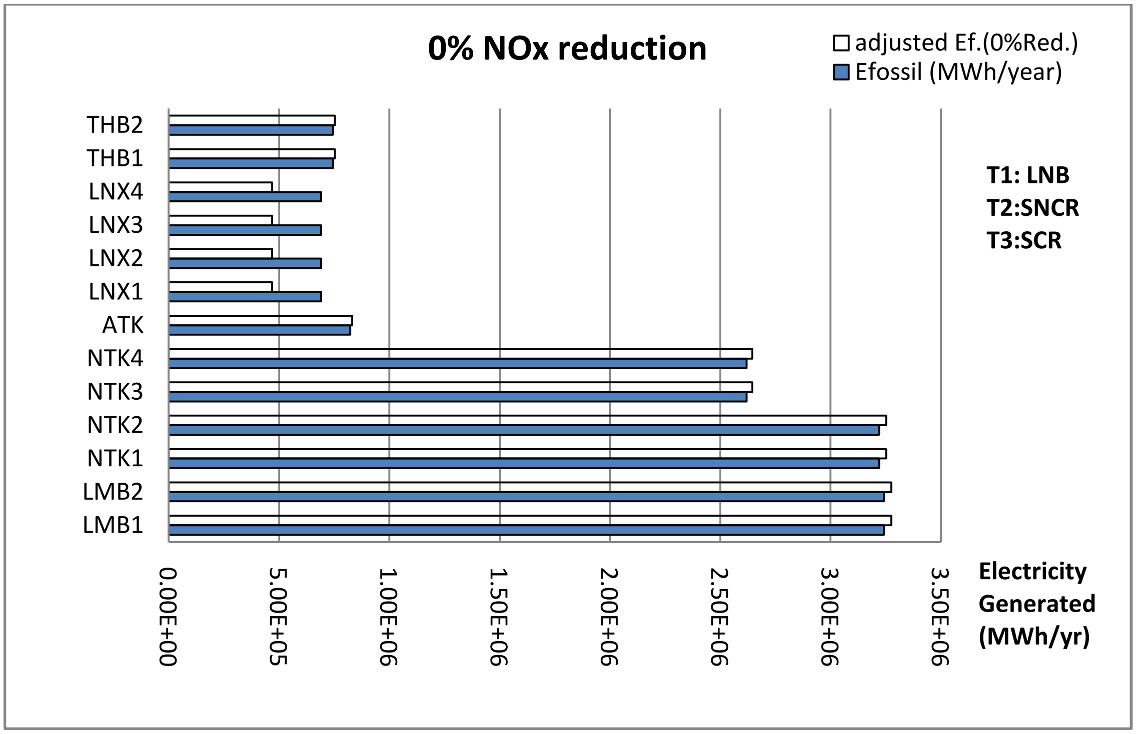

Figure 4.10 Electricity generation strategy for 0% NOx reduction

Figure 4.11 shows the optimization results for the case of 5% NOx reduction target. For this case, we noticed that the model chose to apply selective catalytic reduction (SCR) technology on one unit of Thunder Bay (THB1) power plant and no fuel switching for any plant.The results also show that the capacity factor forall natural gas boilers at Lennox power plant have beenreduced by about 32%.

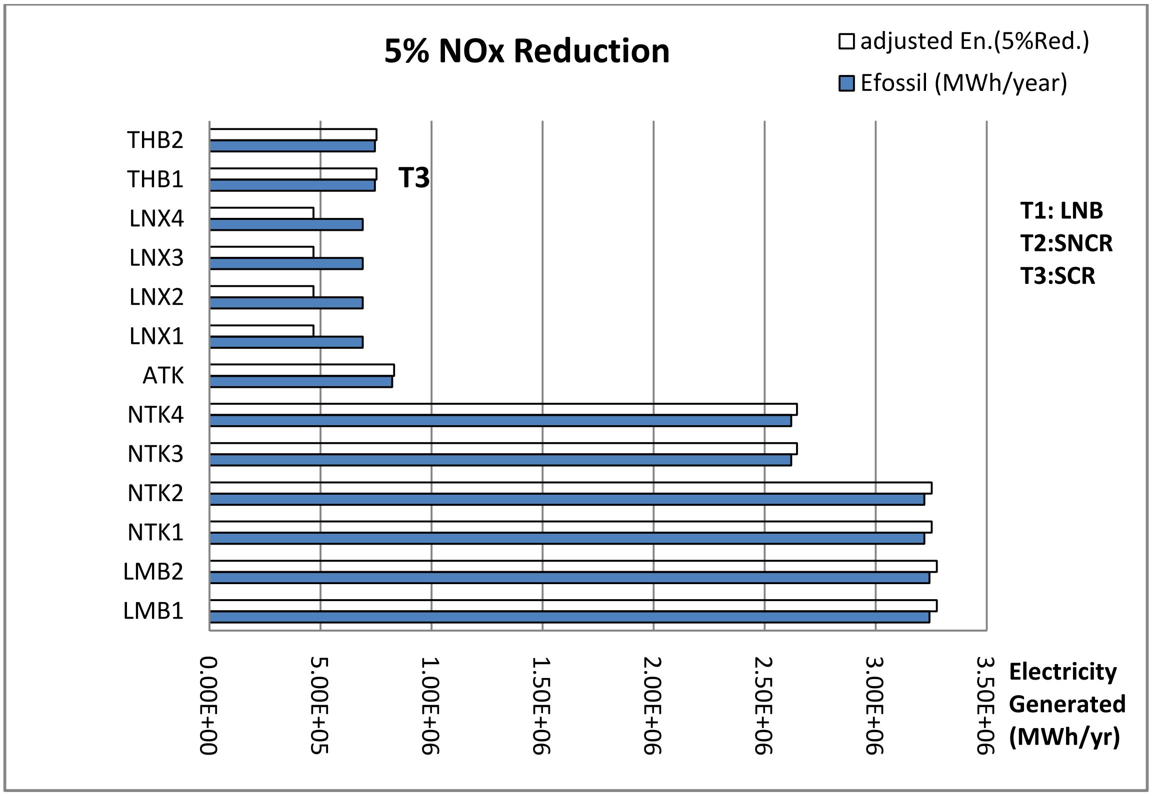

Figure 4.11 Electricity generation strategy for 5% NOx reduction

In order to achieve more than 5% NOx reduction, the optimizer chose to apply one technology on one unit. As seen inFigure 4.12,for 10 % NOx reduction,the results show that in order to achieve a 10% NOx reductionwhile maintaining the electricity to the grid at minimum cost, SCR technology will be installed on one unit of Nanticoke power plant (NTK1). The result also shows that the capacity factor forall natural gas boilersat Lennox power plant have beenreduced by about 32%.

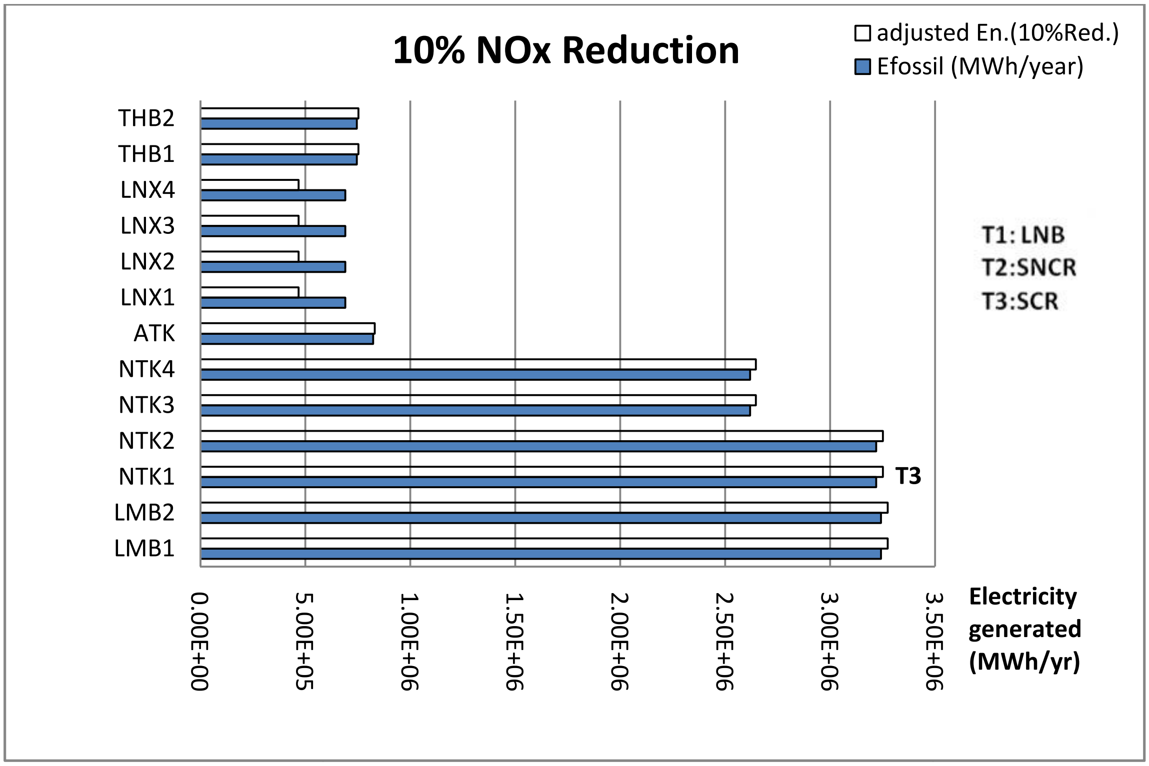

Figure 4.12 Electricity generation strategy for 10% NOx reduction

As higher NOx targets are required, the optimizer considered to implement technologies on more boilers.As seen inFigure 4.13, for 30 % NOx reduction,the result shows that the capacity factor forall natural gas boilersat Lennox power plant have beenreduced by about 32%.The model also decided to apply SCR technology on two units of Nanticoke power plant (NTK3and NTK4), the same thing is true for Atikokan(ATK) and the two boilers at Thunder Bay power plant (THB1and THB2).

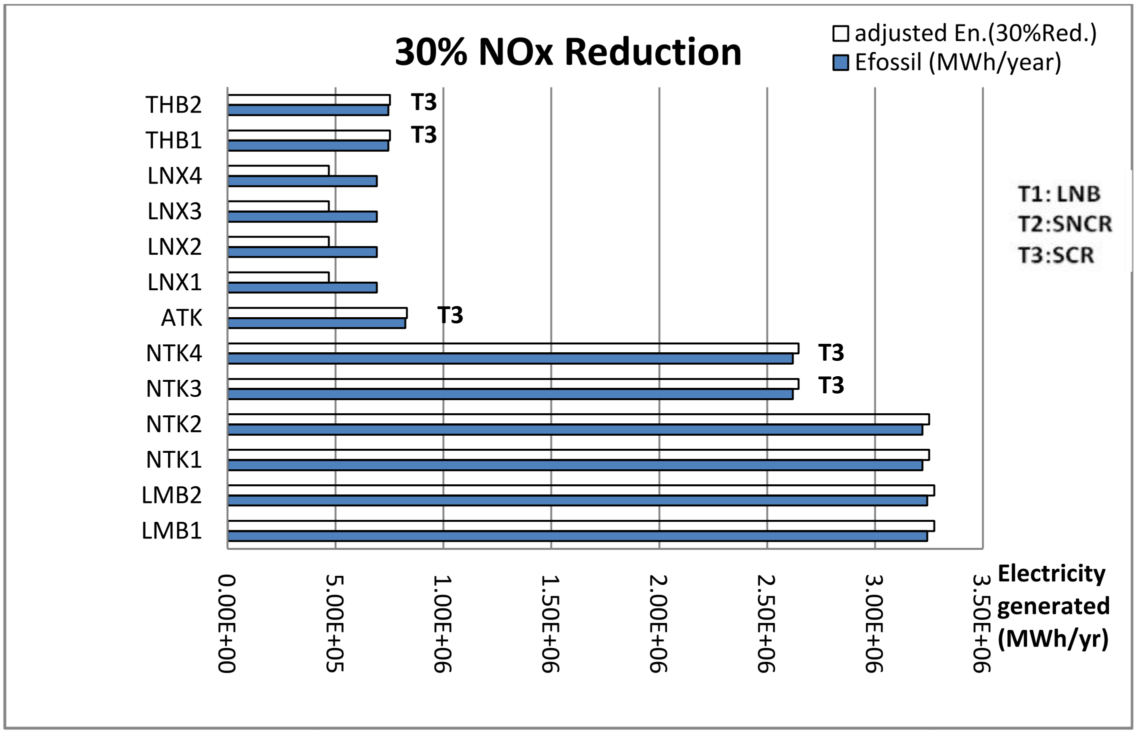

Figure 4.13 Electricity generation strategy for 30% NOx reduction

Higher NOx reduction targets require more technologies to be implemented on boilers. For50 % NOx reduction (see Figure 4.14) the results show that SCR technology will be installed on six boilers - three boilers (NTK1, NTK2 and NTK3) at Nanticoke, one boiler (ATK) at Atikokan and two boilers (THB1and THB2) at Thunder Bay power plants. In addition to installing SCR technology on THB2 at Thunder Bay power plant, the optimization result also shows that the production of this power plant's unitshould be decreased by about 52%. Moreover, the results also show that the power production of3 boilers (NTK4, LNX3 and LNX4) at Nanticoke and Lennox power plants should be decreased by about 28%, 5% and 32% respectively. The resultsshow that the electricity generation from all non fossil fuel power plants has alsobeen increased by 1%.

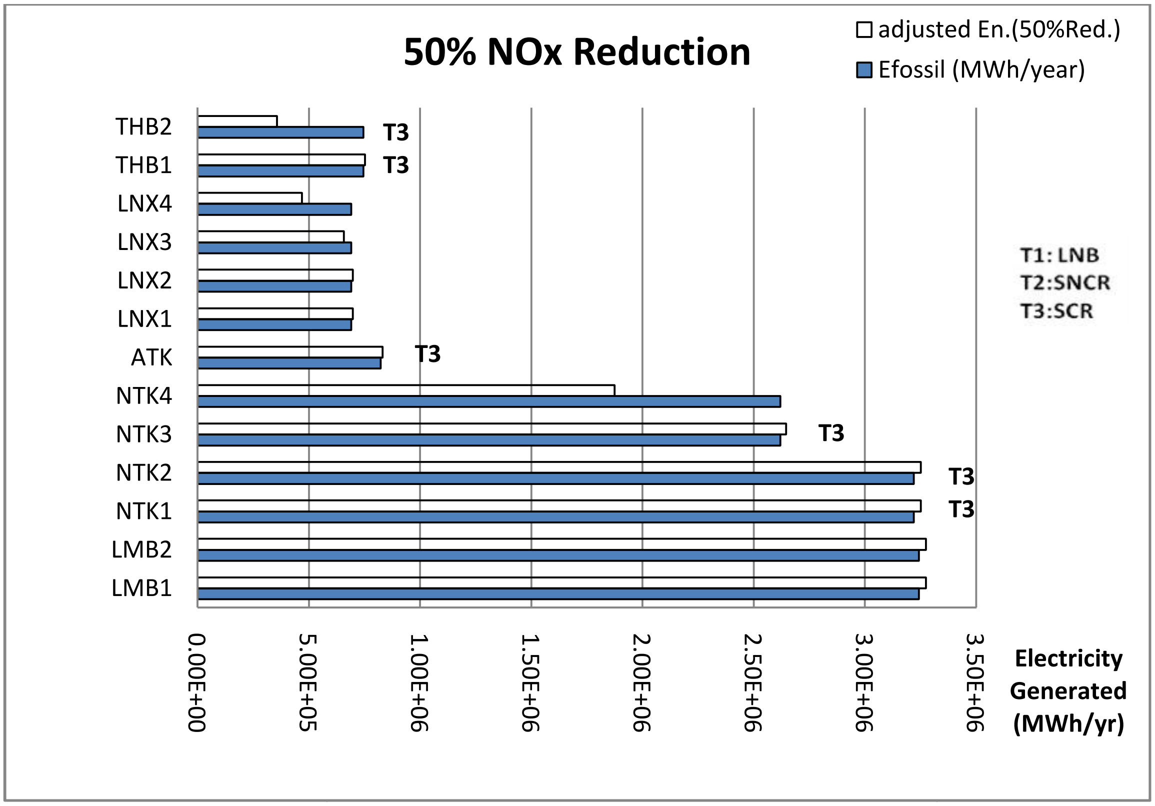

Figure 4.14 Electricity generation strategy for 50% NOx reduction

For the case of 80% NOx reduction, the optimizer recommended to apply SCR technologyfor all the units of the coal power plants – 2 boilers (LMB1 and LMB2) at Lambton, 4 boilers (NTK1, NTK2, NTK3 and NTK4), one boiler (ATK) at Atikokan, 2 boilers (THB1and THB2) at Thunder Bay power plants. The result obtained also shows that the capacity factors for all natural gas boilers at Lennox power plant have been decreased by about 32% as shown inFigure 4.15.

However, it is found that 80% is the maximum possible NOx reduction target and we cannot go beyond that, since the SCR technology can remove up to 85% reductionas reported in the literature.

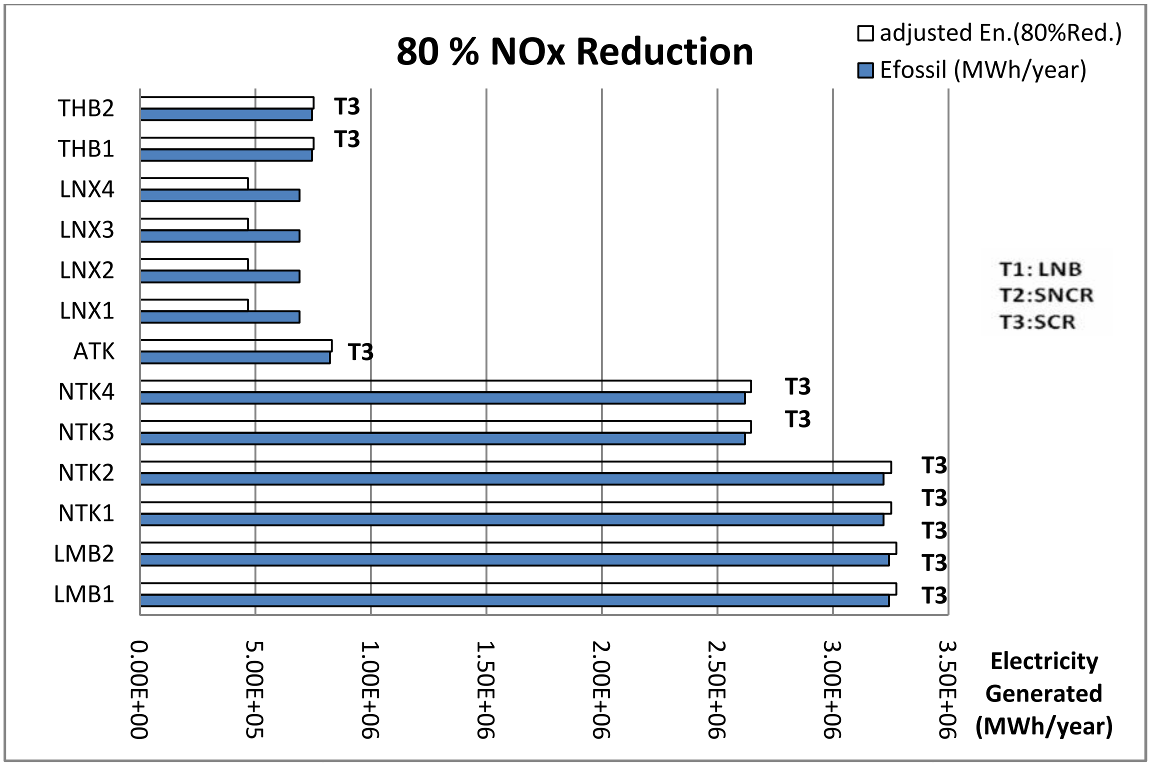

Figure 4.15 Electricity generation strategy for 80% NOx reduction

Table 4.4 below summarizes the results for case 1.B which considers all options .It shows that whether the units (boilers) in the plants needs to be switched to natural gas or not and also if any technology should be implemented or not.The full black squares represent coalboilers while open circles represent natural gas boilers. However, the multiplicationsign and the othersymbol representswitching and installing technologies options respectively. In this case, it is noticed that the model decided to avoid switching any power plant from coal to natural gas for all the reduction targets since the natural gas power plants have high operational cost and our main target is to minimize the cost, so the model chose to install technologies on the power plants rather than switch them to natural gas.

Table 4.4 A summary of the optimization results for case **1.B**

Plant	Base case	*0% NOx reduction*				*5% NOx reduction*				*10 % NOx reduction*			
		S	*LNB*	*SNCR*	*SCR*	*S*	*LNB*	*SNCR*	*SCR*	*S*	*LNB*	*SNCR*	*SCR*
LMB1	■	■	-	-	-	■	-	-	-	■	-	-	-
LMB2	■	■	-	-	-	■	-	-	-	■	-	-	-
NTK1	■	■	-	-	-	■	-	-	-	■	-	-	⌂
NTK2	■	■	-	-	-	■	-	-	-	■	-	-	-
NTK3	■	■	-	-	-	■	-	-	-	■	-	-	-
NTK4	■	■	-	-	-	■	-	-	-	■	-	-	-
ATK	■	■	-	-	-	■	-	-	-	■	-	-	-
LNX1	○	○	-	-	-	○	-	-	-	○	-	-	-
LNX2	○	○	-	-	-	○	-	-	-	○	-	-	-
LNX3	○	○	-	-	-	○	-	-	-	○	-	-	-
LNX4	○	○	-	-	-	○	-	-	-	○	-	-	-
THB1	■	■	-	-	-	■	-	-	⌂	■	-	-	-
THB2	■	■	-	-	-	■	-	-	-	■	-	-	-

Plant	*Base case*	*30% NOx reduction*				*50% NOx reduction*				*80 % NOx reduction*			
		S	*LNB*	*SNCR*	*SCR*	*S*	*LNB*	*SNCR*	*SCR*	*S*	*LNB*	*SNCR*	*SCR*
LMB1	■	■	-	-	-	■	-	-	-	■	-	-	⌂
LMB2	■	■	-	-	-	■	-	-	-	■	-	-	⌂
NTK1	■	■	-	-	-	■	-	-	⌂	■	-	-	⌂
NTK2	■	■	-	-	-	■	-	-	⌂	■	-	-	⌂
NTK3	■	■	-	-	⌂	■	-	-	⌂	■	-	-	⌂
NTK4	■	■	-	-	⌂	■	-	-	-	■	-	-	⌂
ATK	■	■	-	-	⌂	■	-	-	⌂	■	-	-	⌂
LNX1	○	○	-	-	-	○	-	-	-	○	-	-	-
LNX2	○	○	-	-	-	○	-	-	-	○	-	-	-
LNX3	○	○	-	-	-	○	-	-	-	○	-	-	-
LNX4	○	○	-	-	-	○	-	-	-	○	-	-	-
THB1	■	■	-	-	⌂	■	-	-	⌂	■	-	-	⌂
THB2	■	■	-	-	⌂	■	-	-	⌂	■	-	-	⌂

■ : Coal.

○ : Natural Gas.

\- : No technology installed.

⌂ : Technology installed.

Table 4.5shows the total cost and NOx emission for each reduction target. It is clear that increasing the target of NOx reduction will give us ahighertotal annualized cost since it installs more technologies each time the reduction target increased.

Table 4.5 Total cost and NOx emission at different reduction targets for case **1.B**

% NOx Reduction Target	*Total cost ($/yr)*	*Total NOx emission (ton/yr)*	*cost increased %*
0	3.037E+09	36722.152	
5	3.042E+09	35379.029	0.16
10	3.055E+09	31968.469	0.58
30	3.081E+09	24936.062	1.45
50	3.128E+09	18673.01	3.01
80	3.147E+09	7245.177	3.62

4.1.3 Sensitivity analysis

The effect of increase or decrease in the cost of installed technologies was investigated. For an increase of 50% in the technology cost compared to the base case,we noticed that the total annualized cost increases gradually with % percentage for every NOx reduction target as shown in table 4.6. We studied also the effect of decreasing the technology cost with 50%, it isobviously noticed that the total cost for each NOx reduction target increases until we reach 80% NOx reduction. Although SCR technology was installed for all the boilers that running by coal for 80 % NOx reduction target,the total annualized cost was dropped. This is because the model decided to decrease the productivity (capacity factor) of all the boilers that running by natural gas (Lennox power plant) which is the most expensive fuel in OPG's fleet.

As shown in table 4.6 and figure 4.16 below, the result shows that any increase or decrease in the technology cost does not affectthe number of units to be switched to run with natural gas or amount of NO_X reduced.The only affected variable is the total annualized cost.

Table 4.6 Percent increase or decrease in cost of electricity for different NOx reduction targets

% NOx Reduction Target	***Base Case***	***50 % Increasein Technology cost***	***50 % Decreasein Technology Cost***
0			
5	0.16	0.25	0.08
10	0.58	0.88	0.29
30	1.45	2.17	0.72
50	3.01	4.08	1.94
80	3.62	5.43	1.81

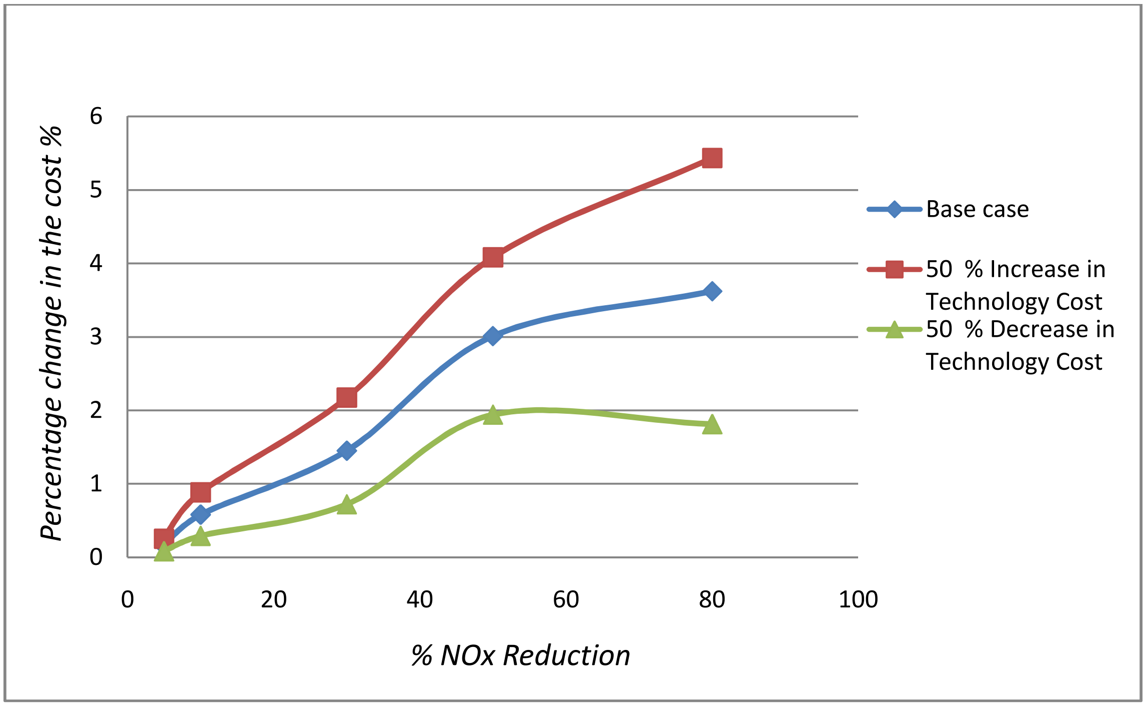

Figure 4.16 Percent increase or decrease in cost of electricity for different NOx reduction targets

4.2Case study 2

This case study will focus on SO_2emitted fromOntario power generation.The objective of this study is to determine the best strategy or mix of strategies for the electricity sector to meet a given SO_2 reduction target at a minimum cost while maintaining adesired production level.Table 4.7shows a general view of OPG fossil fuel generatingstations and SO_2 emission. Since non fossil fuel power plants are assumed not to emit SO_2, the main focus is on electricity generated from the fossil fuel power plants.The operational costs fornuclear, hydroelectric, and wind turbine were estimated to be $43.2, $6.75, and $5.4/MWh,respectively. The nominal conditions for OPG's existing fleet of power plants areshown earlier and given below:

- Total electricity generation: 11884 MW
- Total SO_2 emissions: 80223 ton/yr
- Total operational cost: 3.086×10^9 \$/yr.

Table 4.7 OPG fossil fuel generating stations and SO_2 emission (Atten 2004)

Generating stations	*Fuel used*	*Installed capacity (MW)*	*Number of Units*	*Operational cost ($/MWh)*	*SO_2 emission rate (ton /MWh)*	*Current electricity generated (MWh/year)*
Nanticoke 1(NTK1)	Coal	500	2	40	0.0039	3219300
Nanticoke 2 (NTK2)	Coal	500	2	40	0.0039	2619567
Lambton (LMB)	Coal	500	2	34	0.00286	3242295
Lennox (LNX)	Natural gas	535	4	81	0.00082	690500
Thunder Bay (THB)	Coal	155	2	40	0.006	745000
Atikokan (ATK)	Coal	215	1	40	0.00599	823000

SO_2 emissions were calculated based on emission factors taken from North American Power Plant Air Emissions report(Atten 2004).Three mitigation options to reduce SO_2 emission considered here are fuel balancing, fuel switching and applying different technologies to control SO_2 emission for coal power plants.

In this case study, we considered one technology which is: flue gas desulfurization (FGD) with about 90 % efficiency. The cost effectiveness of this technology as reported in the literature is: $2050 /ton of SO_2 removed. The cost for the technology is amortized with a 10-year lifetime and a 5% annual interest.

The power generation supply system from different types of power stations is represented in a superstructure manner as shown in Figure 4.17.Three different options to reduce SO_2 emissions are also considered in this superstructurerepresentation as shown in Figures 4.18, 4.19 and 4.20 which are fuel balancing, fuel switching and applying flue gas desulfurization (FGD) technology.

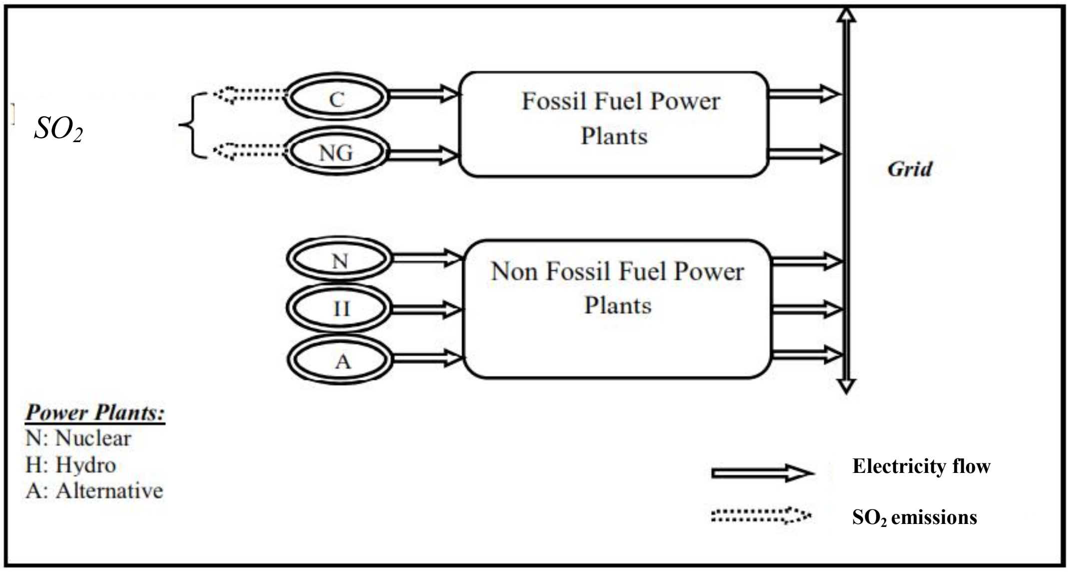

Figure 4.17 Superstructure for power plants

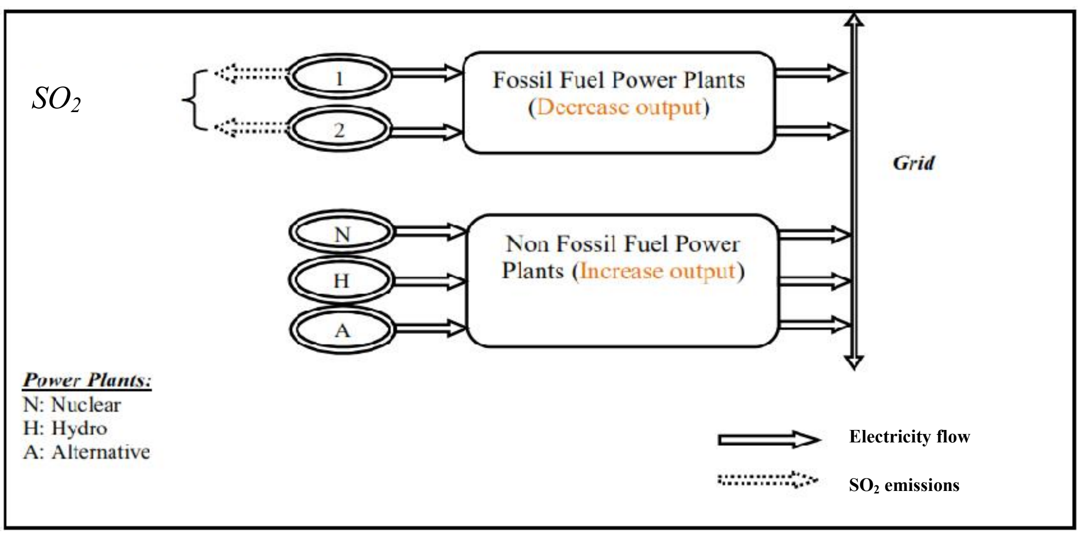

Figure 4.18 Fuel balancing

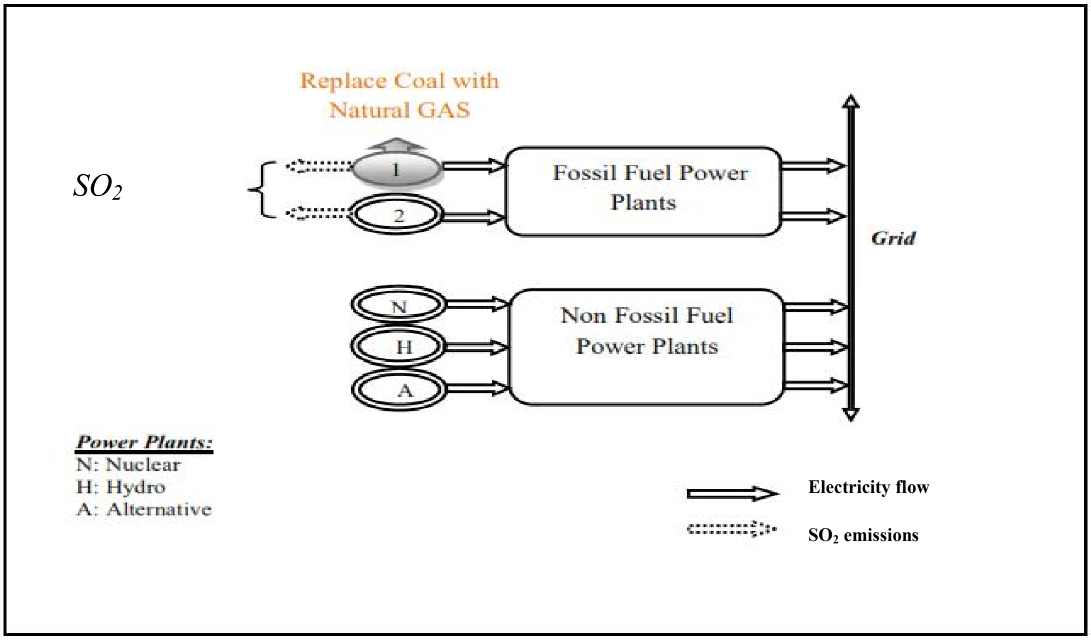

Figure 4.19 Fuel switching

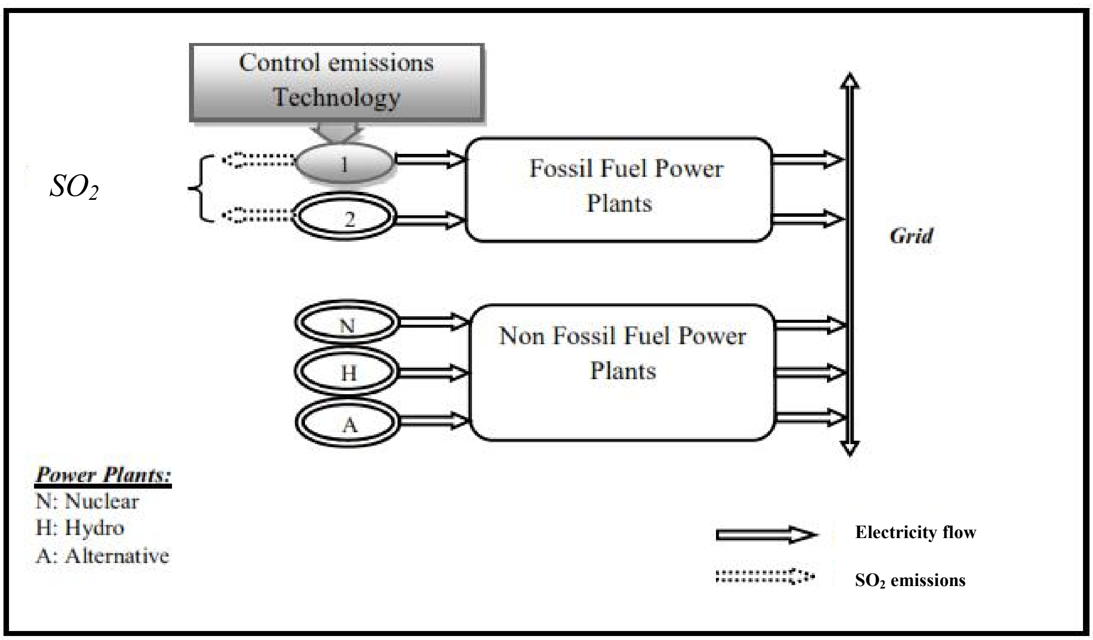

Figure 4.20 Control technologies

As we mentioned earlier, the initial model was MINLP and then it is being normalized. The linearised model discussed earlier in chapter 3 was coded into the General Algebraic Modeling System (GAMS) and solved using the mixed integer linear programming (MILP) solver. Two cases were studied in this case study; case (2.A) will consider two options which are fuel balancing and switching. For case (2.B), all three options will be considered.

4.2.1 Case 2.A

The options considered in this case for the SO_2 reduction are balancing and fuel switching.

The optimization result for the base case (0% SO_2 reduction)shows that all non fossil fuel power plants have to operate with 1% higher than the nominal capacity factor. The only plant for which the capacity factor decreases is the Lennox generating station (natural gas) in which the capacity factor decreased by about 32% .The overall effect of the adjustments in the capacity factors is to reduce the overall SO_2emissions.This result may seem to be expected since the Lennox generating station is fuelled by natural gas which is the most expensive fuel in OPG's fleet. The reduction in SO_2 emissions is achieved by increasing slightly the capacity factor of the non-fossil fuel generating stations (hydro-electric, nuclear and wind) and by decreasing significantly the capacity factor of Lennox. The capacity factors of the other fossil fuel plants were increased by only a small increment.The optimizer tries to satisfy demand of each station by adjusting the operation of existing units e.g., increasing power production from existing non thermal power plants and decreasing it from some existing thermal power plants (fuel balancing) as shown in Figure 4.21. Base case is also shown in the figure for comparison.

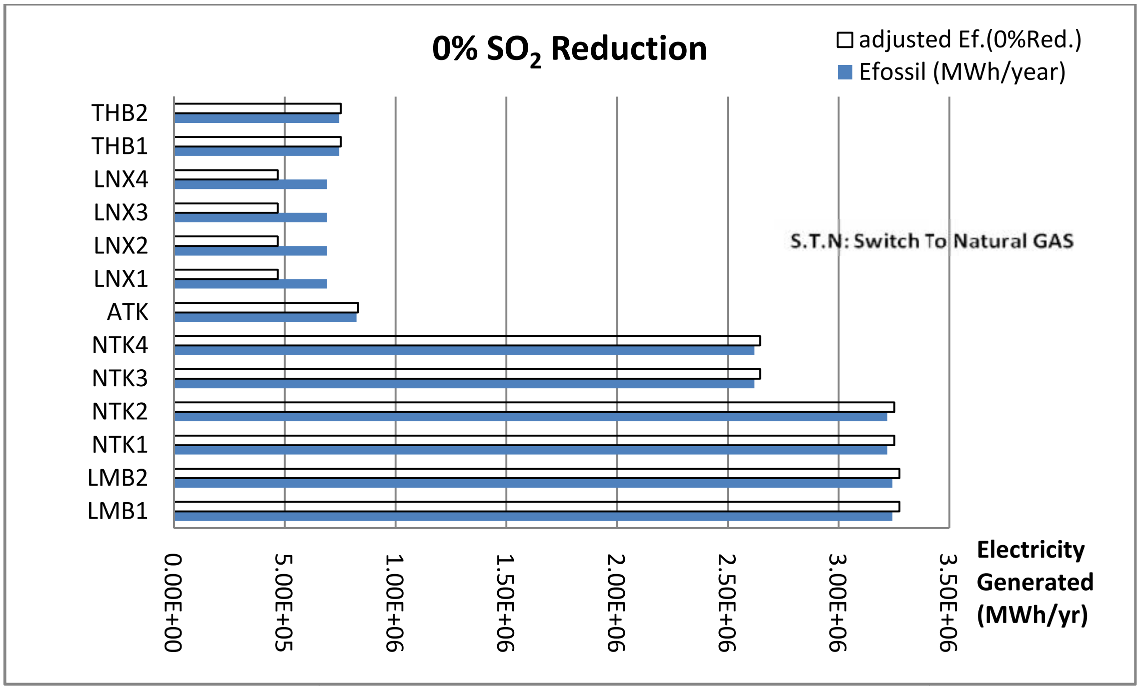

Figure 4.21 Electricity generation strategy for 0% SO_2 reduction

Figure 4.22 shows the optimization results for the case of 5% SO_2 reduction target. For this case, we noticed that the optimizer chose to switch one unit (THB1) at Thunder Bay power plant from coal to natural gas. The result obtained also shows that the capacity factors for all natural gas boilers at Lennox power plant have been decreased by about 32%. In addition to switching of one boiler (THB1) at Thunder Bay power plant from coal to natural gas, the results also showed that thecapacity factor of this power plant should be decreased by about 14%.

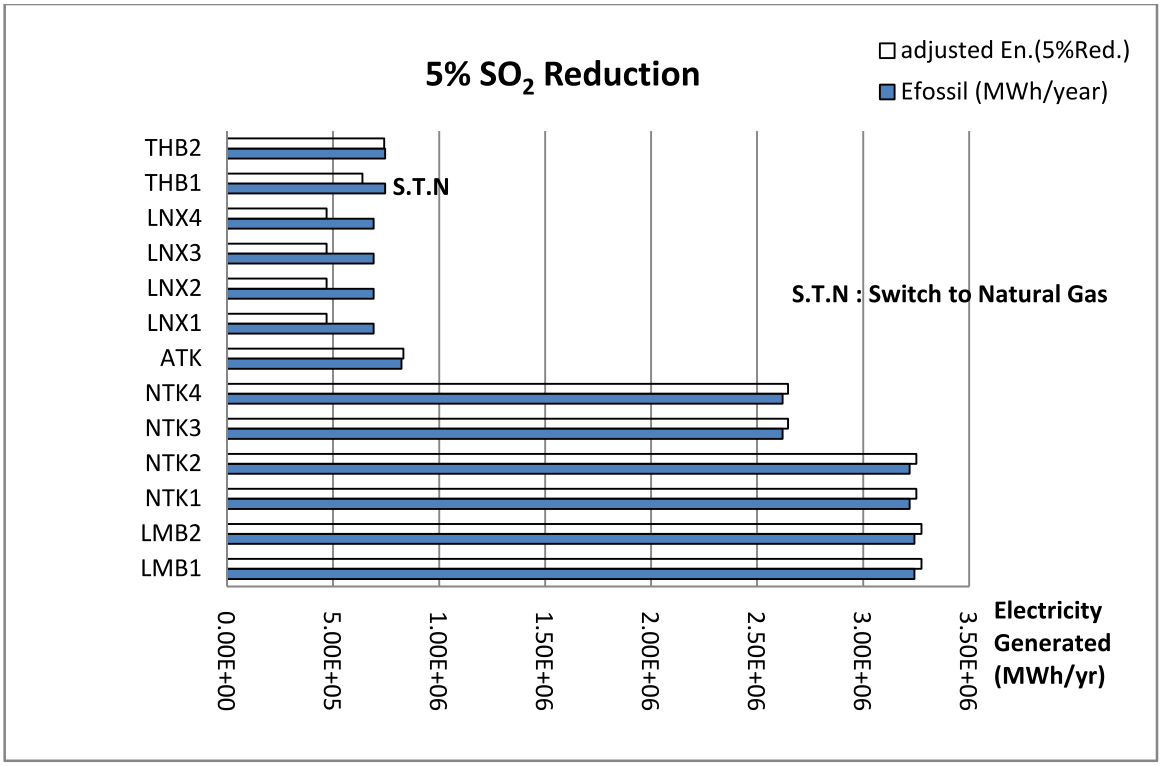

Figure 4.22 Electricity generation strategy for 5% SO_2 reduction

In order to achieve more than 5% SO_2 reduction, the model chose to switch more than one unit. This involves fleet changes from coal to natural gas. As seen inFigure4.23, for example, the optimization results show that in order to achievea 10% SO_2 reductionwhile maintaining the electricity to the grid at minimum cost, the capacity factor forall natural gas boilers have beenreduced by 32%,two boilers at Thunder Bay (THB1and THB2) need to be switched from coal to natural gas. The capacity factors for the non-fossilfuel generating stations should be increased by 1%which is always the case. Furthermore, thecapacity factor of one unit (THB1) at Thunder Bay power plant should be decreased by about 11%. Thesame thing is true for Atikokan power plant (ATK) should be decreased by about 3%.

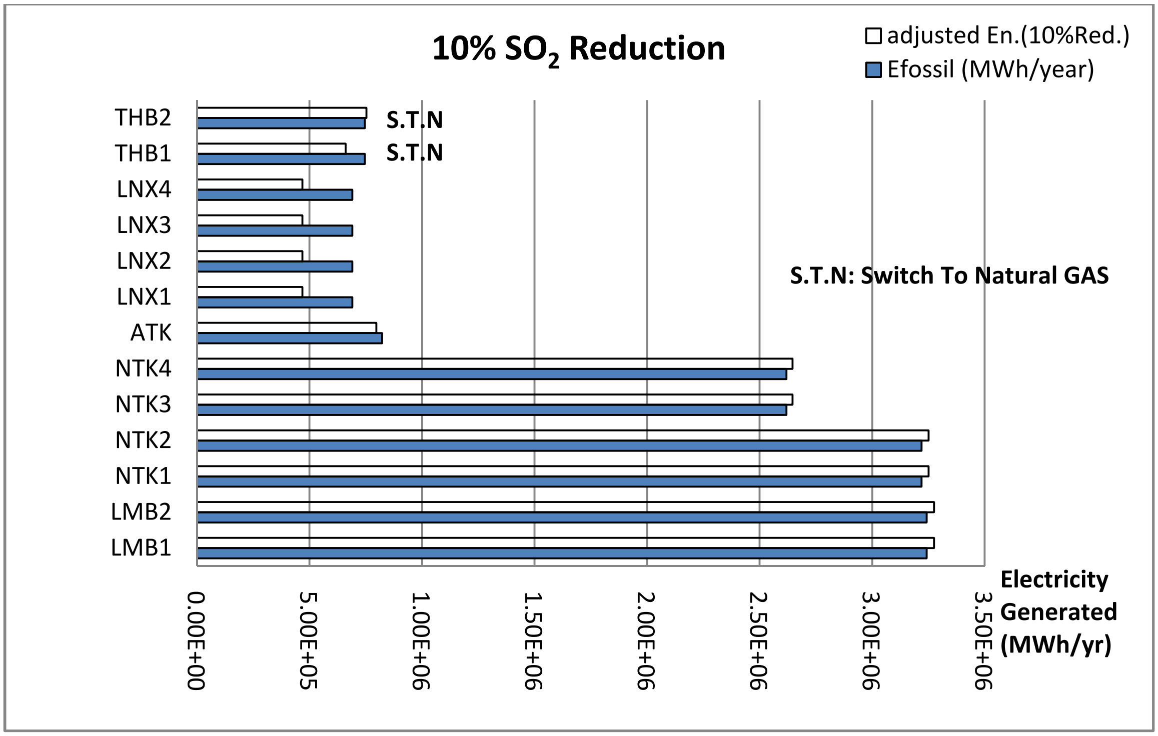

Figure 4.23 Electricity generation strategy for 10% SO_2 reduction

As higher SO_2 targets are required, the optimizer will choose more coal boilers to be switched to natural gas.For the case of 30% SO_2reduction(see Figure 4.24)the results show that4boilerswhich are running by coal need to be switched to natural gas one boiler at Nanticoke ,one boiler at Atikokan and two boilers at Thunder Bay power plants respectively (NTK1,ATK,THB1and THB2).The result also shows that the capacity factor fortwonatural gas boilers at Lennox power plant(LNX2 and LNX4) have beenreduced by about27 and 32% respectively,andthe same thing is true forone coal fired boiler at

Nanticoke power plant (NTK2) have been decreased by about 18%.The electricity generationfrom all non fossil fuel power plants has also been increased by 1%.

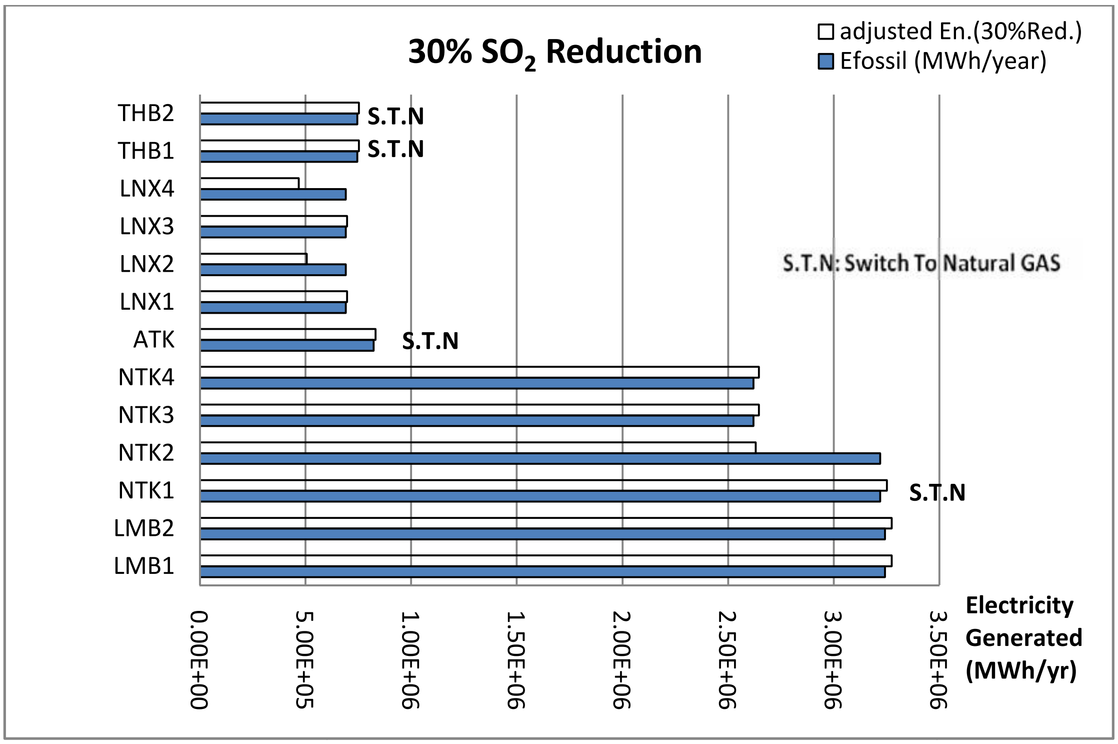

Figure 4.24 Electricity generation strategy for 30% SO_2 reduction

For a higher reduction target,such as 50 %(see Figure 4.25),more coal power plants must be switched to operatewith natural gas. The result shows that 6 boilerswhich are running by coal need to be switched to natural gas, - three boilers (NTK1, NTK2 and NTK3) at Nanticoke, one boiler (ATK) at Atikokan and two boilers (THB1and THB2) at Thunder Bay power plants. The results also show thatthe electricity generation from all non fossil fuel power plants has alsobeen increased by 1%.The result also shows that the capacity factor forall natural gas boilersat Lennox power plant have beenreduced by about 32% and the same thing is true for Atikokan power plant (ATK) by about 14%.

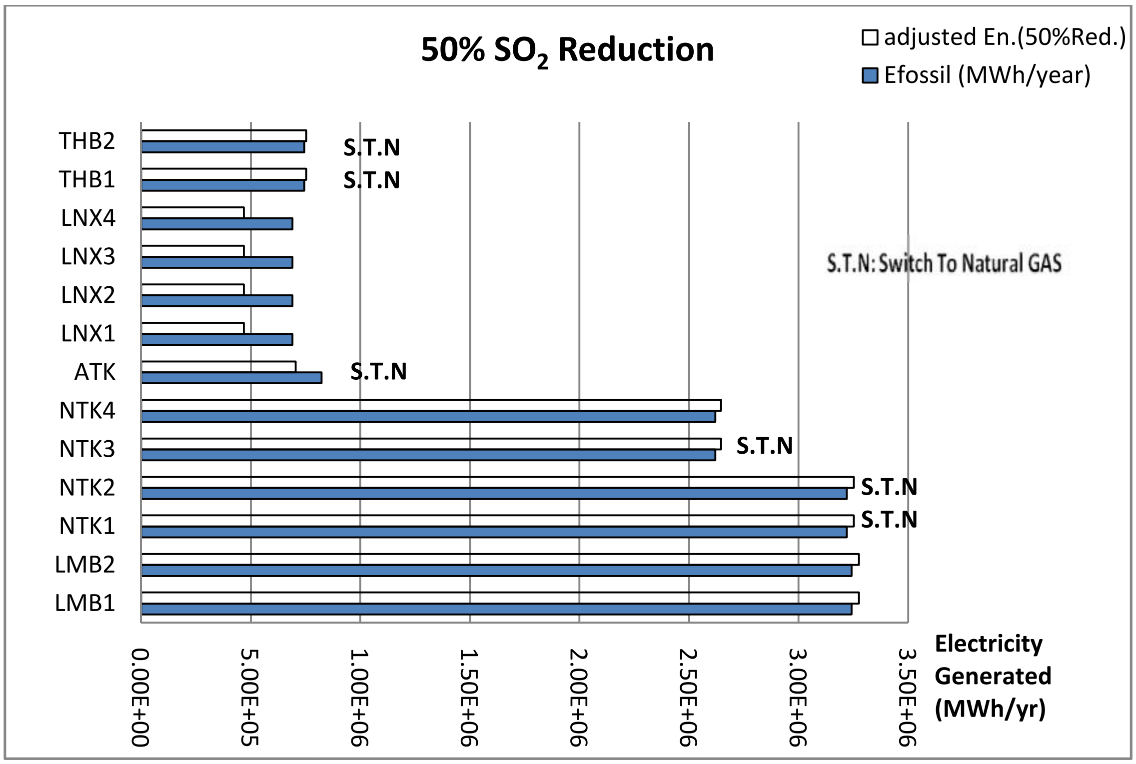

Figure 4.25 Electricity generation strategy for 50% SO_2 reduction

For the case of 70% SO_2 reduction, the optimizer recommended to switch all units from coal to natural gas except one unit at Lambton (LMB1).However, the result obtained shows that the capacity factor for this unit of Lambton power plant (LMB1) has been decreased by about 14% as shown in Figure 4.26.The result also shows that the capacity factor forthree natural gas boilers at Lennox power plant (LNX1, LNX2 and LNX4) have beenreduced by about 12,32 and 32% respectively.

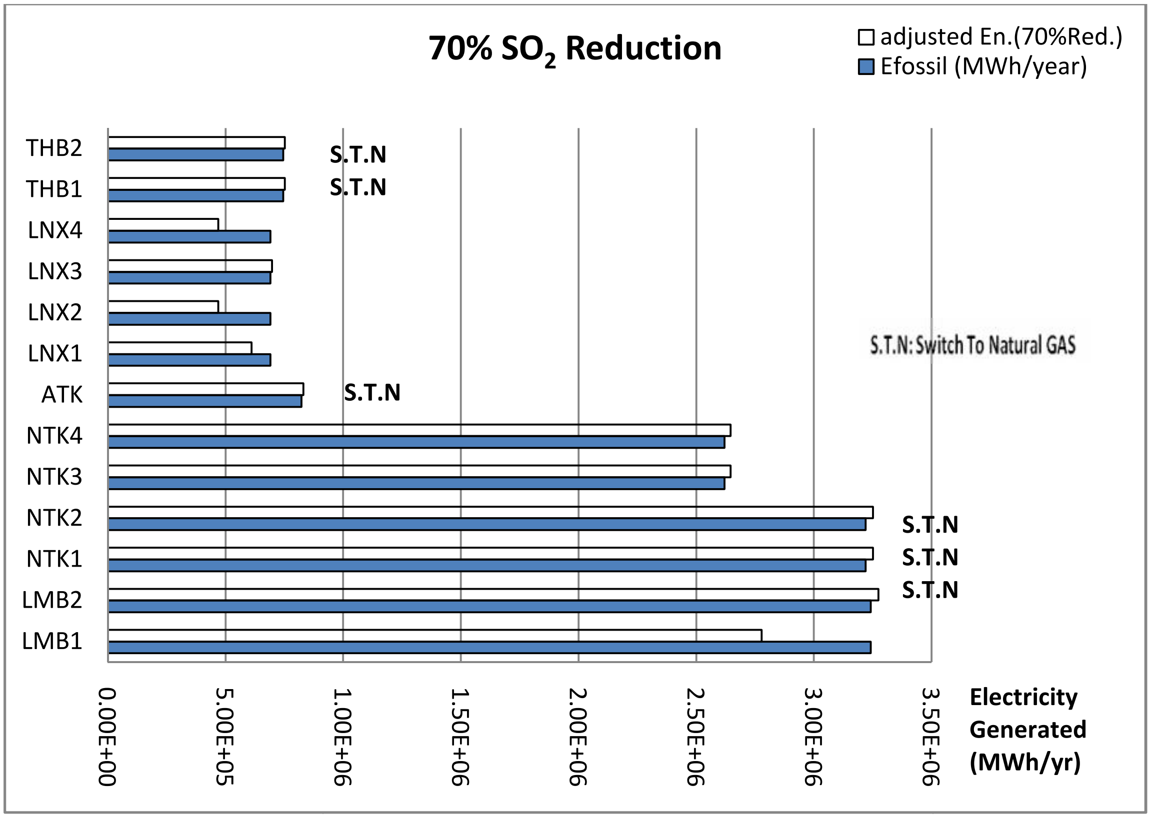

Figure 4.26 Electricity generation strategy for 70% SO_2 reduction

In order to achieve 75% SO_2 reduction, the optimizer decided to switch all coal power plants to operate with natural gas .The result obtained also show that the capacity factors for all natural gas boilers at Lennox power plant have been decreased by about 32% as shown in Figure 4.27.The result also show that the capacity factor forone boiler at Nanticoke power plant (NTK1) have beenreduced by about 3%.

However, it is found that 75% is the maximum possible SO_2 reduction target and we cannot achieve more than that.

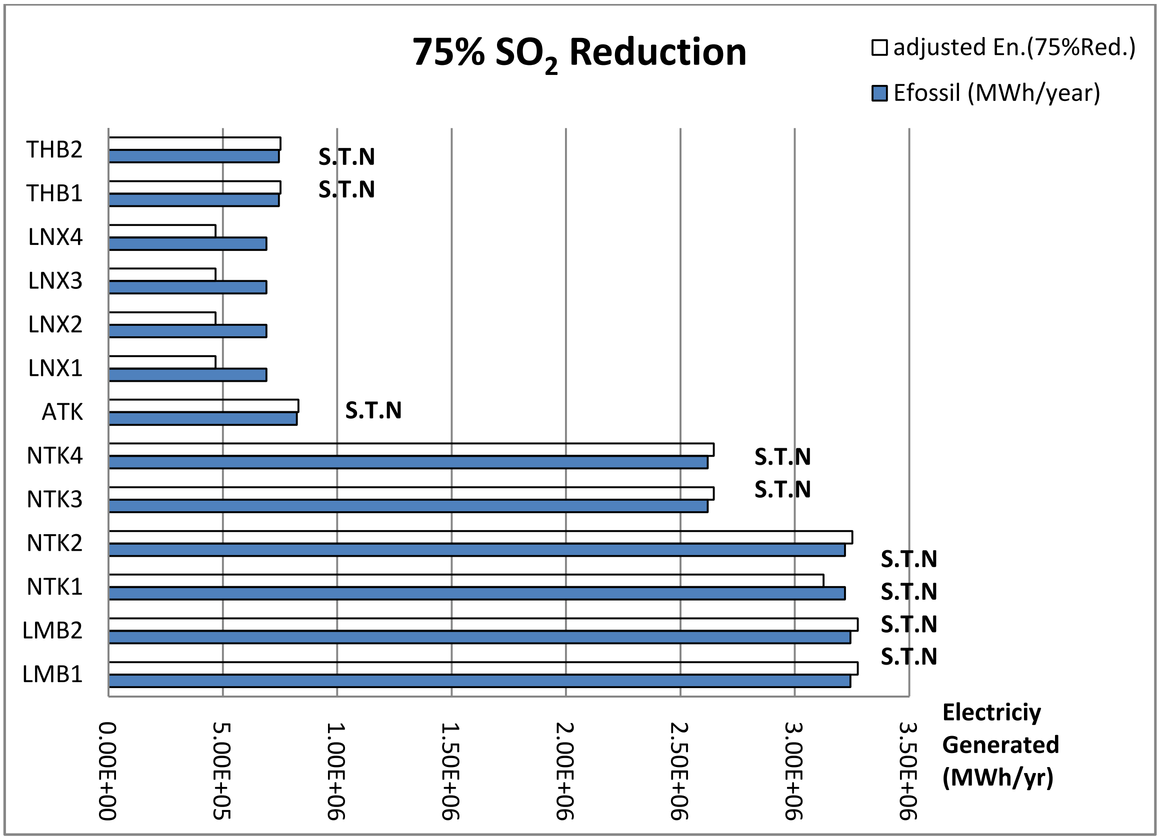

Figure 4.27 Electricity generation strategy for 75% SO_2 reduction

Table4.8 below summarizes the results for case (2.A).It shows that whether the units (boilers) in the plants needs to be switched to natural gas or not for different reduction targets.The full black squares represent coalboilers while open circles represent natural gas boilers. However, the multiplication sign represents the switching option.

Table 4.8 A summary of the optimization results for case **2.A**

Plant	*Base case*	*0% SO_2Reduction*	*5% SO_2 Reduction*	*10% SO_2 Reduction*	*30% SO_2 Reduction*
LMB1	▪	▪	▪	▪	▪
LMB2	▪	▪	▪	▪	▪
NTK1	▪	▪	▪	▪	×
NTK2	▪	▪	▪	▪	▪
NTK3	▪	▪	▪	▪	▪
NTK4	▪	▪	▪	▪	▪
ATK	▪	▪	▪	▪	×
LNX1	○	○	○	○	○
LNX2	○	○	○	○	○
LNX3	○	○	○	○	○
LNX4	○	○	○	○	○
THB1	▪	▪	×	×	×
THB2	▪	▪	▪	×	×

Plant	*Base case*	*50% SO_2 Reduction*	*70% SO_2 Reduction*	*75% SO_2 Reduction*
LMB1	▪	▪	▪	×
LMB2	▪	▪	×	×
NTK1	▪	×	×	×
NTK2	▪	×	×	×
NTK3	▪	×	×	×
NTK4	▪	▪	×	×
ATK	▪	×	×	×
LNX1	○	○	○	○
LNX2	○	○	○	○
LNX3	○	○	○	○
LNX4	○	○	○	○
THB1	▪	▪	×	×
THB2	▪	▪	×	×

▪ : Coal

○ : Natural Gas

× : Switch to Natural gas

Table 4.9 shows the total cost and SO_2 emission for each reduction target. Obviously increasing the reduction target will lead to ahighertotal annualized cost since it involves structural change such as switch some of thecoal power plants to natural gas.

Table 4.9 Total cost and total SO_2 emission at different reduction targets for case **2.A**

% SO_2 Reduction Target	***Total cost ($/yr)***	***Total SO_2 emission (ton/yr)***	***Cost increased %***
0	3.04E+09	80223.7	
5	3.05E+09	76212.515	0.42
10	3.06E+09	72201.33	0.92
30	3.17E+09	56156.59	4.22
50	3.26E+09	39907.701	7.22
70	3.39E+09	24067.11	11.63
75	3.43E+09	18401.215	13.03

4.2.2 Case 2.B

All three mitigation options to reduce SO_2 emission are considered here which arefuel balancing, fuel switching and implementing flue gas desulfurization (FGD) technology.

The model gives us the same results as case (2.A) for 0% SO_2 reduction when two mitigation options (fuel balancing and fuel switching) considered for the base case (0% SO_2 reduction) when all threemitigation options considered. The results show that all non fossil fuel power plants have to operate with 1% higher than the nominal capacity factor. The only plant for which the capacity factor decreases is the Lennox generating station (natural gas) in which the capacity factor decreased by about 32% .The model tries to satisfy demand of each station by adjusting the operation of existing units e.g., increasing production from existing non thermalpower plants and decreasing it from some existing thermal power plants (fuel balancing) as shown in Figure4.28.

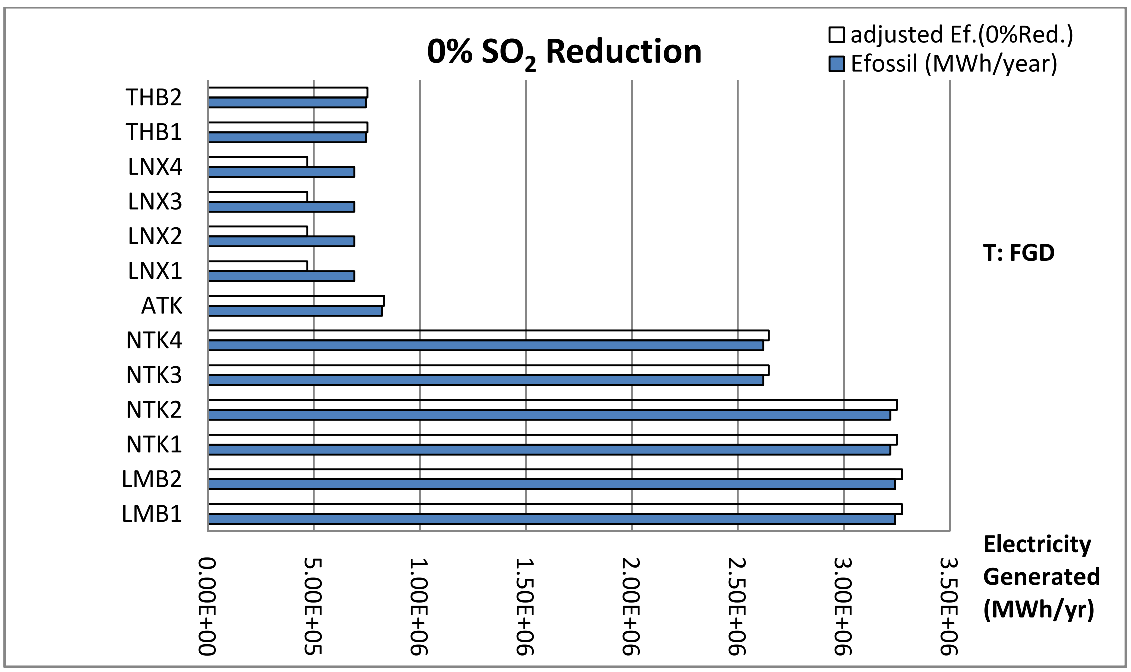

Figure 4.28 Electricity generation strategy for 0% SO_2 reduction

Figure 4.29 shows the optimization results for the case of 5% SO_2 reduction target. For this case, we noticed that the model chose not to switch any unit from coal to natural gas and not to install any technology for any power plant.The results also show that the capacity factor fortwo natural gas boilers at Lennox power plant (LNX2and LNX4) have beenreduced by about 6 and 32% respectively.And alsothe production fromtwo coal fired boilers at Thunder Bay power plant (THB1 and THB2)have been decreased by about 19 and 82% respectively.

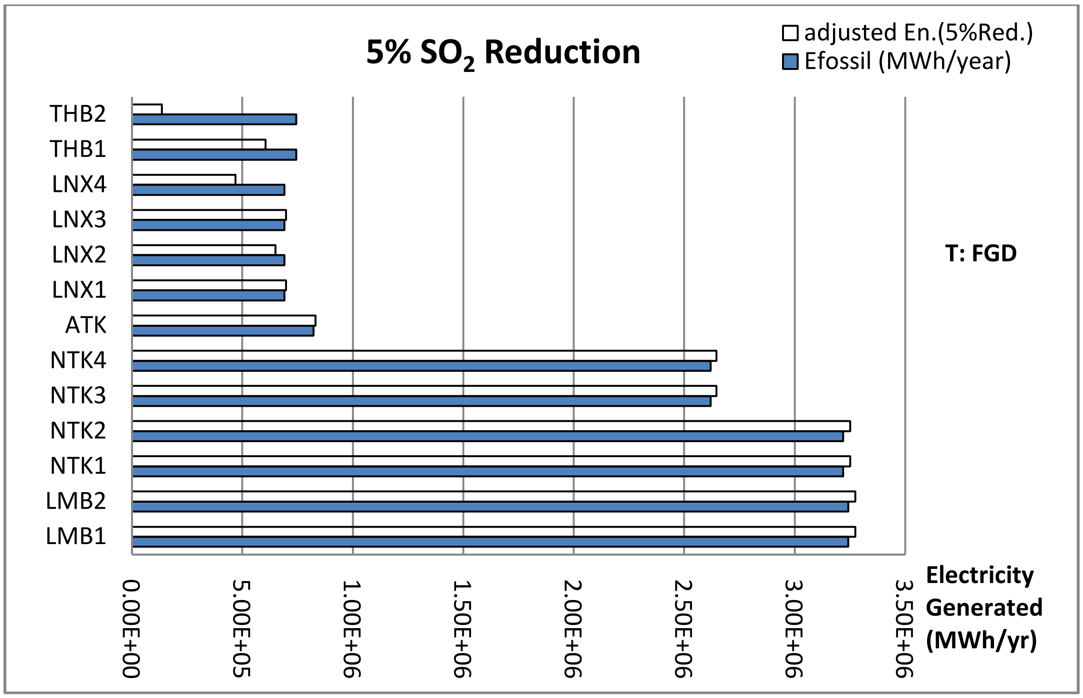

Figure 4.29 Electricity generation strategy for 5% SO_2 reduction

In order to achieve more than5 % SO_2 reduction, the optimizer chose to apply flue gas desulfurization (FGD) technology on one unit. As seen inFigure 4.30, for example,for 10 % SO_2 reduction,the results show that in order to achieve10% SO_2 reductionwhile maintaining the electricity to the grid at minimum cost, FGD technology will be installed on one unit of Nanticoke power plant (NTK3). The result also shows that the electricity produced fromall natural gas boilersat Lennox power plant havebeenreduced by about 32%.

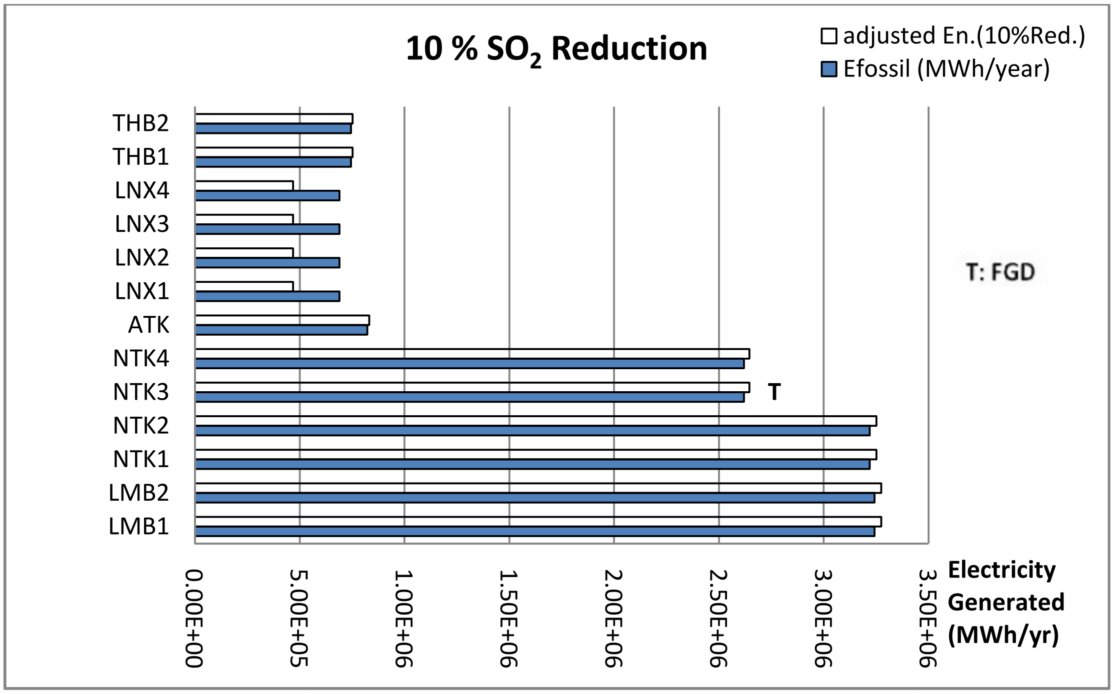

Figure 4.30 Electricity generation strategy for 10% SO_2 reduction

As higher SO_2 targets are required, the optimizer considered to implement technologies on more boilers.As seen inFigure 4.31, for 30 % SO_2 reduction,the result shows that the capacity factor forall natural gas boilersat Lennox power plant have beenreduced by about 32%.The model also decided to apply FGD technology on one unit of Nanticoke power plant (NTK2), the only boiler at Atikokan(ATK) and the same thing is true fortwo boilers (THB1and THB2) at Thunder Bay power plant.

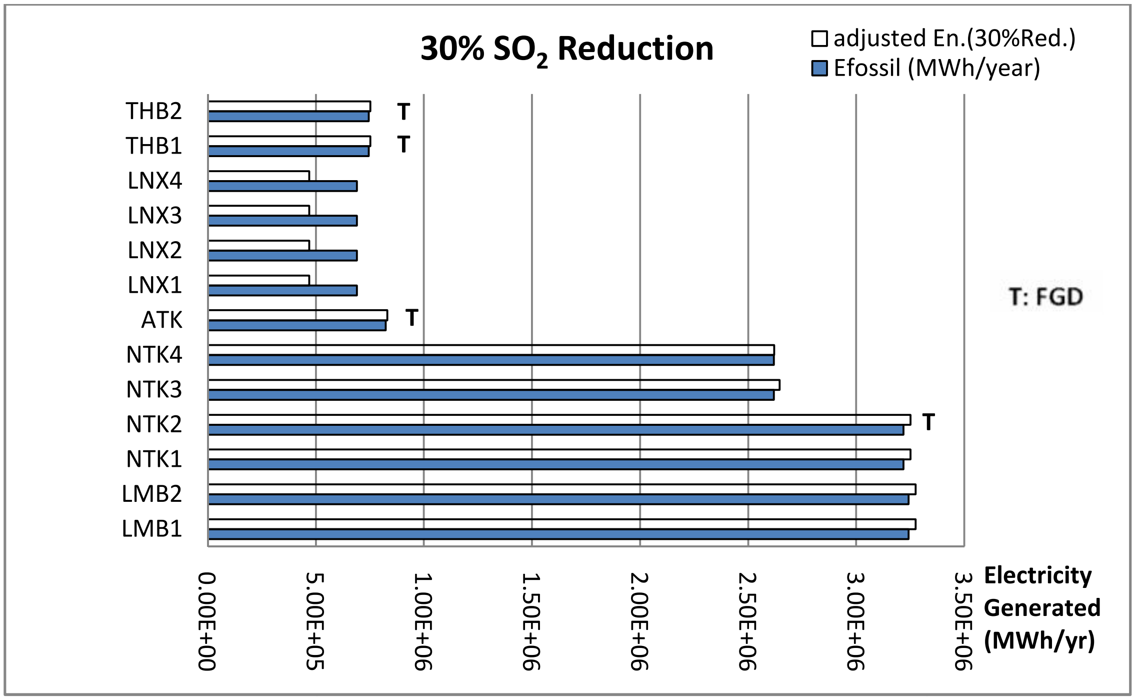

Figure 4.31 Electricity generation strategy for 30% SO_2 reduction

Higher SO_2 reduction targets require more technologies to be implemented on boilers. For 50 % SO_2 reduction (see Figure 4.32) the results show thatthe electricity generation from all non fossil fuel power plants has alsobeen increased by 1%.The optimization result also shows that FGD technology will be installed on six boilers - three boilers (NTK1, NTK2 and NTK3) at Nanticoke, one boiler (ATK) at Atikokan and two boilers (THB1and THB2) at Thunder Bay power plants. The result also shows that the capacity factor forall natural gas boilersat Lennox power plant have beenreduced by about 32%.

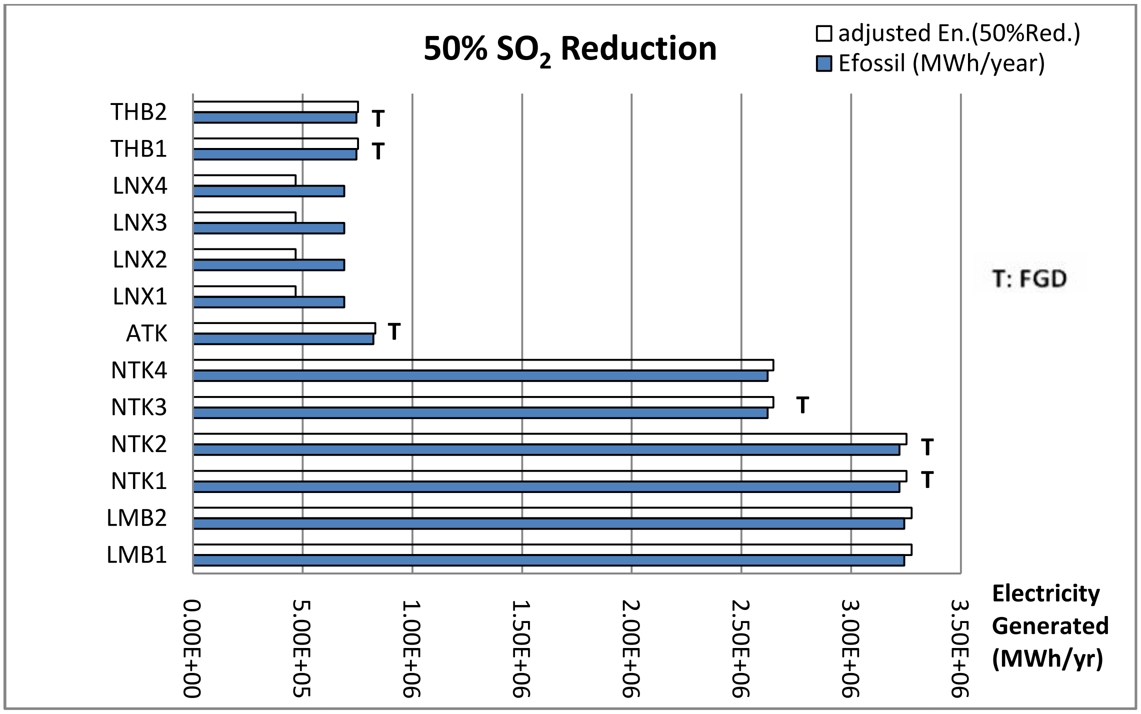

Figure 4.32 Electricity generation strategy for 50% SO_2 reduction

For the case of 80% SO_2 reduction, the optimizer recommended to apply FGD technology for all the units of the coal power plants except one unit at Lambton (LMB1).However, the result obtained shows that the capacity factor for this unit of Lambton power plant (LMB1) hasbeen decreased by about 25% as shown inFigure 4.33.

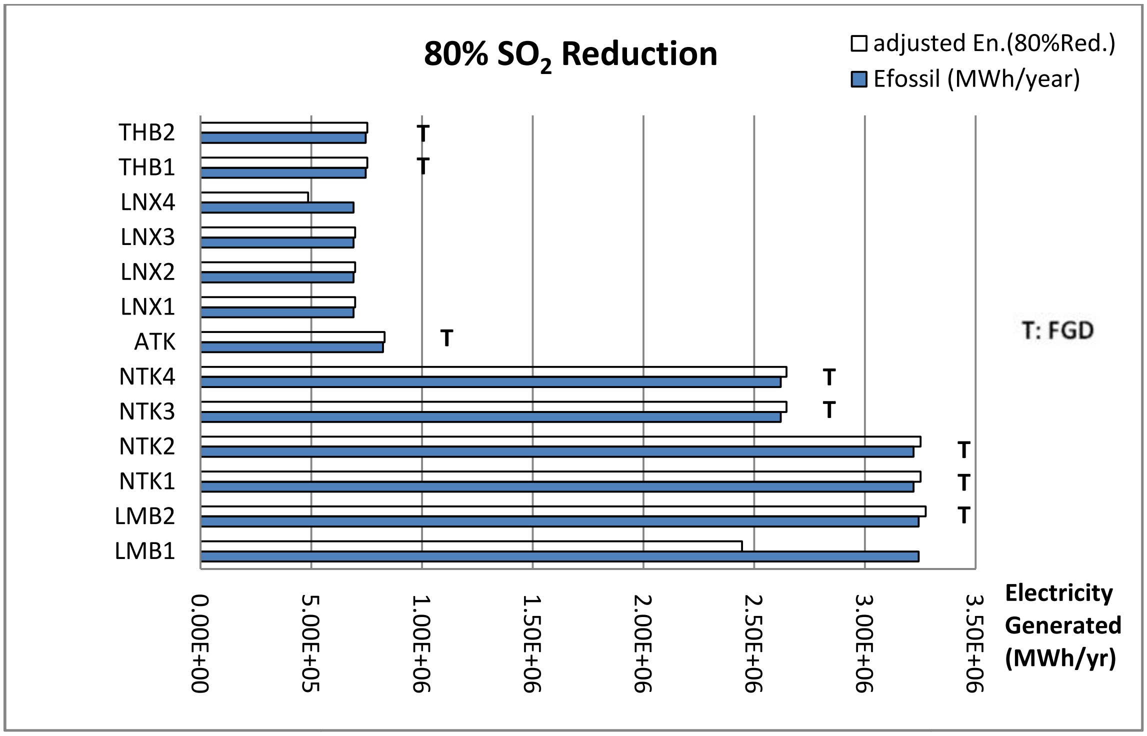

Figure 4.33 Electricity generation strategy for 80% SO_2 reduction

In order to achieve 85% SO_2 reduction, the optimizer decided to install FGD technology for all the units of the coal power plants – 2 boilers (LMB1 and LMB2) at Lambton, 4 boilers (NTK1, NTK2, NTK3 and NTK4), one boiler (ATK) at Atikokan, 2 boilers (THB1and THB2) at Thunder Bay power plants. The result obtained also shows that the power production form all natural gas boilers at Lennox power plant have been decreased by about 32% as shown inFigure 4.34.

However, it is found that 85% is the maximum possible SO_2 reduction target and we cannot go beyond that, since the FGD technology can remove up to 90% reductionas reported in the literature.

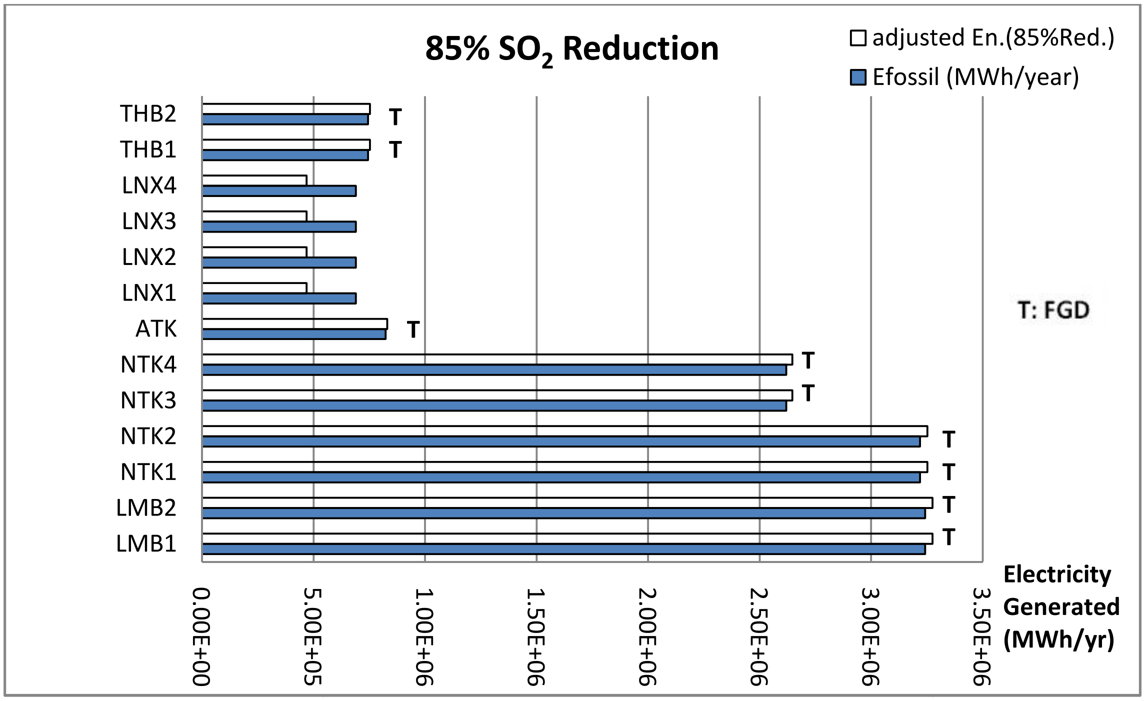

Figure 4.34 Electricity generation strategy for 85% SO_2 reduction

Table 4.10 below summarizes the results for case 2.B which considers all options .It shows that whether the units (boilers) in the plants needs to be switched to natural gas or not and also if any technology should be implemented or not.The full black squares represent coalboilers while open circles represent natural gas boilers. However, the multiplicationsign and the other symbol represent switching and installing technologies options respectively. In this case, it is noticed that the model decided to avoid switching any power plant from coal to natural gas for all the reduction targets since the natural gas power plants have high operational cost and our main target is to minimize the cost, so the model chose to install technologies on the power plants rather than switch them to natural gas.

Table 4.10 A summary of the optimization results for case **2.B**

Plant	Base case	0% SO_2 reduction		5% SO_2 reduction		10% SO_2 reduction	
		S	FGD	S	FGD	S	FGD
LMB1	■	■	-	■	-	■	-
LMB2	■	■	-	■	-	■	-
NTK1	■	■	-	■	-	■	-
NTK2	■	■	-	■	-	■	-
NTK3	■	■	-	■	-	■	⌂
NTK4	■	■	-	■	-	■	-
ATK	■	■	-	■	-	■	-
LNX1	○	○	-	○	-	○	-
LNX2	○	○	-	○	-	○	-
LNX3	○	○	-	○	-	○	-
LNX4	○	○	-	○	-	○	-
THB1	■	■	-	■	-	■	-
THB2	■	■	-	■	-	■	-

Plant	Base case	30% SO_2 reduction		50% SO_2 reduction		80% SO_2 reduction		85% SO_2 reduction	
		S	FGD	S	FGD	S	FGD	S	FGD
LMB1	■	■	-	■	-	■	-	■	⌂
LMB2	■	■	-	■	-	■	⌂	■	⌂
NTK1	■	■	-	■	⌂	■	⌂	■	⌂
NTK2	■	■	⌂	■	⌂	■	⌂	■	⌂
NTK3	■	■	-	■	⌂	■	⌂	■	⌂
NTK4	■	■	-	■	-	■	⌂	■	⌂
ATK	■	■	⌂	■	⌂	■	⌂	■	⌂
LNX1	○	○	-	○	-	○	-	○	-
LNX2	○	○	-	○	-	○	-	○	-
LNX3	○	○	-	○	-	○	-	○	-
LNX4	○	○	-	○	-	○	-	○	-
THB1	■	■	⌂	■	⌂	■	⌂	■	⌂
THB2	■	■	⌂	■	⌂	■	⌂	■	⌂

■ : Coal.

○ : Natural Gas.

\- : No technology installed.

⌂ : Technology installed.

Table 4.11shows the total cost and SO_2 emission for each reduction target. It is clear that increasing the reduction target will lead to ahighertotal annualized cost since it installs more technologies each time the reduction target increased.

Table 4.11 Total cost and total SO_2 emission at different reduction targets for case **2.B**

% SO_2 Reduction Target	***Total cost ($/yr)***	***Total SO_2 emission (ton/yr)***	***Cost increased %***
0	3.04E+09	80223.7	
5	3.06E+09	76212.515	0.86
10	3.06E+09	70989.026	0.69
30	3.09E+09	56156.59	1.79
50	3.14E+09	35555.925	3.32
80	3.22E+09	16044.74	5.96
85	3.21E+09	9411.05	5.68

4.2.3Sensitivity analysis

The effect of increase or decrease the cost of installed technologies was studied for this case. For an increase of 50% in the technology cost compared to the base case, we noticed that the total annualized cost increases gradually with % percentage for every SO_2reduction target as shown in table 4.12. We investigated also the effect of decrease the technology cost with 50%, it isobviously noticed that the total cost for 5% SO_2 reduction target was equal to the total cost for the base case (86% cost increased).For a 10 % SO_2 reduction target, we noticed that the total annualized cost was dropped to 34% because of decreasing the capacity factor for the boilers which are running by natural gas (the most expensive fuel) at Lennox power plant. Then the total cost will increase as the SO_2 reduction target increases because the model chose to apply FGD on more units until we reach 85% SO_2 reduction, we noticed that the total cost decreased and the reason behind that is also decreasing the capacity factor for the boilers which are running by natural gas (the most expensive fuel) at Lennox power plant.

As shown in table 4.12 and Figure 4.35below, the result shows that any increase or decrease in the technology cost does not affectthe number of units to be switched to run with natural gas or amount of SO_2 removed.The only affected variable is the total annualized cost.

Table 4.12 Percent increase or decrease in cost of electricity for different SO_2 reduction targets

% SO_2Reduction	***Base case***	***50 % Increase in Technology Cost***	***50 % Decrease in Technology Cost***
0			
5	0.86	0.86	0.86
10	0.69	1.37	0.34
30	1.79	2.72	0.89
50	3.32	4.48	1.66
80	5.96	8.38	3.54
85	5.68	8.46	2.84

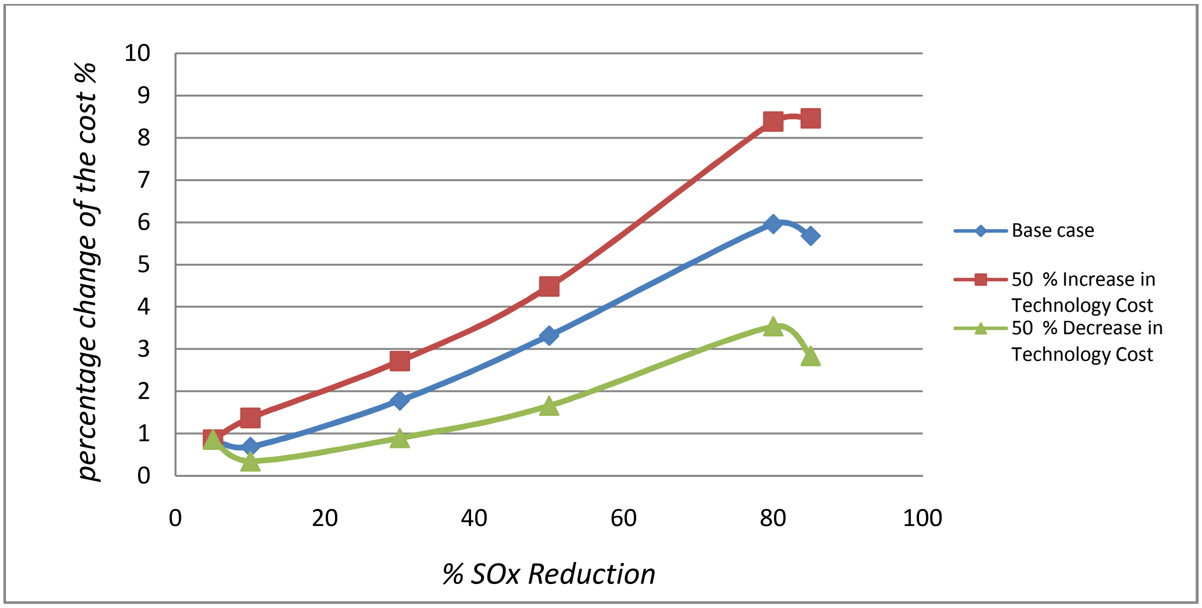

Figure 4.35 Percent increase or decrease in cost of electricity for different SO_2 reduction targets

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

A general mathematical model was formulatedand applied into real case studies taken from Ontario Power Generation (OPG).Three different mitigation options were considered to reduce NOx and SO_2 and these are: fuel balancing, fuel switching and implementing different technologies.

Based on modeling findings, this study achieved the objective of developing a linearisedmodel that isable to realizethe optimalstrategy or mix of strategies for the electricity sector to meet a given SO_2 or NOx reduction target at a minimum cost while maintaining a desired production level.The model wasimplemented in GAMS (General Algebraic Modeling System) and applied to the Ontario Power Generation set ofpower plants. Two case studies (1 and 2) were illustrated: the first one considers NOx emission reduction, and the second one considers SO_2 emission reduction.

The first case study considers two cases; the first case (1.A) involves two reduction options, fuel balancing and fuel switching, and the second case (1.B)involves one more option in addition to the two mentioned options which is application of NOx control technologies.

Case1.A: For the case of no NOx mitigation option (0% NOx reduction), the optimization result shows that the reduction in NOx emissions is achieved by increasing slightly the capacity factor of the non-fossil fuel generating stations (hydro-electric, nuclear and wind) and by decreasing significantly the capacity factor of Lennox. The capacity factors of the other fossil fuel plants were increased by only a small increment.However,fuel balancing can achieve up to small reduction in NO_X emissions (3%), so if NOx emissions are to be reduced further , it will be essential to implement another option such as fuel switching. For higher reduction targets (from 5 up to 30 %), fuel switching considered the best option of choice.

For the case in which all options are considered***(Case 1.B)***: For the base case (0% NOx reduction),The model tries to increase power production from existing non thermalpower plants and decreasepower production from some existing thermal power plants (fuel balancing) to meet demand. For higher reduction up to 80%, no fuel switching was implemented and the model did not choose this option due to its cost .However, the results indicate that applying SCR technology is the best option to reduce NOx emissions.

Sensitivity analysis was carried out in this case and the results show that any increase or decrease in the technology cost neither affectthe number of units to be switched to natural gas nor amount of NO_X reduced.The only affected variable is the total annualized cost.

The second case study considersthe second emission which is SO_2. In this study, two cases were investigated.Two reduction options (fuel balancing and fuel switching) were studied in the first case (2.A) and the other case (2.B) studied all three mitigation options included the application of SO_2 control technology.

***Case 2.A*:**The optimization results for the case of a 0% SO_2 reduction target show that all non fossil fuel power plants have to operate with 1% higher than the nominal capacity factor.

The reduction in SO_2 emissions is achieved by increasing slightly the electricity production of the non-fossil fuel generating stations while decreasing significantly the electricity production of Lennox power plant (fuel balancing).However,fuel balancing can achieve up to small reduction in SO_2 emissions (3%), so if SO_2 emissions are to be reduced further, it will be essential to implement another option such as fuel switching. For higher reduction targets (from 5 up to 75 %), fuel switching involving structural changes to the fleet has been considered as the optimum option for SO_2 reduction.

Case 2.B: For the base case (0% SO_2 reduction) ,The model tries to satisfy demand of each station by adjusting the operation of existing boilers e.g., increasing production from existing non thermalpower plants and decreasing production from some existing thermal power plants (fuel balancing). For higher reduction up to 85%, no fuel switching was implemented and the optimization model did not select this option due to its cost .However, the results show that applying FGD technology is the best option to reduce SO_2 emissions.

Sensitivity analysis was carried out also in this case, and the result indicate thatthe only affected variable is the total annualized cost sinceany increase or decrease in the technology cost neither affectthe number of units to be switched to natural gas nor amount of SO_2 removed.

5.2 Recommendations

Based on the results of this study, the following recommendations are made to extend the scope of the research area:

- Build a new power plant and incorporate it in the model to meet electricity demand in case of higher demand.
- Apply this mathematical model on a real case study from Saudi Arabia.

APPENDIXES

APPENDIX A

GAMS CODE

(OPTIMAL NOx REDUCTION STRATEGIES FOR OPG)

```
$title Optimal NOx reduction strategies for OPG
$Ontext
*The objective of this model is to determine the best mix of power plants,
*fuels, annual capacity factor to meet the electricity demand while satisfying
*the NOxreduction target at minimum cost.
$offtext
*
*.. list all sets
*
 Set i   plant type      /Fossil, nuclear, hydro, wind/
     F   fossil plants   /L1,L2,N1,N2,N3,N4,A1,
                         LN1,LN2,LN3,LN4,TB1,TB2/
     N   nuclear         /Pick-A,Pick-B,Darling/
     H   hydroelectric   /NW-Cari,NW-Car,NW-Mani,NW-White,NW-Silv,NW-Kaba,
                         NW-Came,NW-Pine,NW-Alex,NW-Aqua,NW-Aub,NW-WElls,
                         NW-Ray,NW-Red,NE-Kip,NE-Harm,NE-Otter,NE-Smok,
                         NE-Long,NE-Abi,NE-Sturg,NE-Sandy,NE-Wawai,NE-Ind,
                         NE-Hound,NE-Notch,NE-Mata,O-Huld,O-Joa,O-Chen,
                         O-Cala,O-Barr,O-Mount,O-Stew,O-Amp,O-Chats,O-Saund,
                         N-DeCew,N-DeCew2,N-Beck1,N-Beck2,N-Beck3,E-Mc,
                         E-Conis,E-Crys,E-Nipi,E-Bing,E-Elli,E-Ragg,E-Eddy,
                         E-Chute,E-Hanna,E-Treth,E-South,E-High,E-Mern,
```

```
                    E-Lake,E-Heal,E-Sey,E-Ran,E-Aub,E-Eugen,E-Sills,
                    E-Hag,E-Frank,E-Sid,E-Meyer/
    W   wind          /Tiverton/
    k   technology     /LNB,SNCR,SCR/
    j   fuels          /coal,ng/;
*
*.. list all scalars
*
 Scalar MaxE     Electricity generated at peak time (MWe) /13000/;
 Scalar Optime   Annual operating time (hr per year) /8760/;
 Scalar NOx      NOx emission in tonne per year /37346.02/;
Scalar HydOpr   Operating cost for hydroelectric ($ per MWh) /6.75/;
 Scalar WindOpr  Operating cost for wind ($ per MWh) /5.4/;
 Scalar R        allowable electricity increment /0.01/;
 Scalar nk       number of technology /3/;
*
*.. list all parameters
*
Parameters
Fmax(F)         Maximum fossil electricity generation(MWh per year)
 /L1           4323020
  L2           4323020
  N1           4292400
  N2           4292400
  N3           4292400
  N4           4292400
  A1           1883400
  LN1          4686600
  LN2          4686600
```

LN3 4686600

LN4 4686600

TB1 1357800

TB2 1357800/

Efossil(F) Electricity from fossil power plants in (MWh per year)

/L1 3242295

L2 3242295

N1 3219300

N2 3219300

N3 2619567

N4 2619567

A1 823000

LN1 690500

LN2 690500

LN3 690500

LN4 690500

TB1 745000

TB2 745000/

Enuclear(N) Electricity from nuclear power plants in MWh per year

/Pick-A 0

Pick-B 14300000

Darling 27600000/

Ehydro(H) Electricity from hydroelectric power plants in MWh per year

/NW-Cari 347328

NW-Car 88128

NW-Mani 373248

NW-White 352512

NW-Silv	248832
NW-Kaba	129600
NW-Came	414720
NW-Pine	720576
NW-Alex	347328
NE-Sandy	15768
NE-Wawai	57816
NE-Ind	15768
NE-Hound	21024
NE-Notch	1440144
NE-Mata	52560
O-Huld	1277208
O-Joa	2254824
O-Chen	756864
O-Cala	26280
O-Saund	5340096
N-DeCew	120888
N-DeCew2	756864
N-Beck1	2617488
N-Beck2	7384680
N-Beck3	914544
E-Mc	15768
E-Conis	26280
E-Crys	42048
E-Nipi	10512
E-Bing	5256
E-Elli	10512
E-Ragg	42048
E-Eddy	42048

```
 E-Chute      52560
 E-Hanna     5256
 E-Treth      10512
 E-South      21024
 E-High       15768
 E-Mern       10512
 E-Lake       10512
 E-Eugen      31536
 E-Sills     10512
 E-Hag        21024
 E-Frank      15768
 E-Sid       21024
 E-Meyer      21900/
Ewind(W)       Electricity from wind turbine power plants in MWh per year
/Tiverton      713000/
perRed(k)      reduction
/  LNB          0.35
   SNCR          0.5
   SCR          0.8/;
Table  FosOpr(F,j)     Operational cost ($ per MWh)

         coal        ng
 L1       34.425      52.85
 L2       34.425      52.85
 N1       40.5        58.93
 N2       40.5        58.93
 N3       40.5        58.93
 N4       40.5        58.93
 A1       40.5        58.93
```

```
 LN1       81          81
 LN2       81          81
 LN3       81          81
 LN4       81          81
 TB1       40.5        58.93
 TB2       40.5        58.93 ;
parameter Rcost(F) retrofit cost (million $ per year)
/L1           2347644
 L2           2347644
 N1           2330994
 N2           2330994
 N3           2330994
 N4           2330994
 A1           1022783
 LN1          0
 LN2          0
 LN3          0
 LN4          0
 TB1          737355
 TB2          737355/;
Table  NOxemis(F,j) NOx emission from fossil (tonne per MWh)
       coal      ng
 L1    0.00147   0.0010903
 L2    0.00147   0.0010903
 N1    0.00172   0.0010905
 N2    0.00172   0.0010905
 N3    0.00172   0.0010905
 N4    0.00172   0.0010905
 A1    0.00193   0.0010907
```

```
 LN1    0.00109   0.00109
 LN2    0.00109   0.00109
 LN3    0.00109   0.00109
 LN4    0.00109   0.00109
 TB1    0.0021    0.0010909
 TB2    0.0021    0.0010909;
Table  CO(F,k)
        LNB        SNCR        SCR
 L1      9151053    11820111    15251756
 L2      9151053    11820111    15251756
 N1      10631416   13732246    17719027
 N2      10631416   13732246    17719027
 N3      8650858    11174025    14418097
 N4      8650858    11174025    14418097
 TB1     3003840    3879960     5006400
 TB2     3003840    3879960     5006400;
parameter NomE    Nominal electricity generated in MW;
*
 NomE     =(sum(F,Efossil(F))+sum(N,Enuclear(N))+sum(H,Ehydro(H))
        +sum(W,Ewind(W)))/(Optime);
*
 Display NomE;
*
*.. list all variables
*
 Positive Variables
   En(N)    adjusted electricity generation for nuclear power plants
   Eh(H)    adjusted electricity generation for hydroelectric power plants
  gama(F,j,k)   new var for linearization;
```

```
 Variables cost;
Binary variables
   X(F,j)  fuel selection
   Y(F,k) technology selection;

*.. list all the equations
*
 Equations
   totcost total annual cost for all power generation stations ($ per year)
   totNOx  total NOx emission (tone per year)
   totMW   total electricity generation (MWh per year)
   te(F)
   swi(F)
   newF(F,j)
   newN(N)
   newH(H)
   newW(W)
 newcon1(F,j,k)
*   newcon2(F,j,k)
   newcon3(F,j,k)
  newcon4(F,j,k)
   low(F,j)
   control(F);

    totcost.. cost =e=(sum((F,j),Efj(F,j)*FosOpr(F,j))+
                sum(F,Rcost(F)*X(F,'ng'))+sum(N,En(N)*NucOpr)+
                sum(H,Eh(H)*HydOpr)+sum(W,Ew(W)*WindOpr)+
                sum((F,k),co(F,k)*y(F,k)));
```

```
  totNOx.. sum((F,j),NOxemis(F,j)*Efj(F,j))- sum((F,j,k),NOxemis(F,j)*perRed(k)
             *gama(F,j,k))=l= (1-NOxred)*NOx;

  totMW..  (sum((F,j),Efj(F,j))+sum(N,En(N))+sum(H,Eh(H))+sum(W,Ew(W)))/Optime
          =g=1.00*NomE;
newF(F,j).. Efj(F,j) =l= (1+R)*Efossil(F)*X(F,j);
newN(N).. En(N) =l= (1+R)*Enuclear(N);
newH(H).. Eh(H) =l= (1+R)*Ehydro(H);
newW(W).. Ew(W) =l= (1+R)*Ewind(W);
low(F,j).. Efj(F,j) =g= (L*Fmax(F))*X(F,j);
control(F).. sum(k,y(F,k))=l=1;
 cost.l = 1;
*
*.. define model name
*
 Model  model1 /all /;
*
*.. more commands
*
 option LIMROW = 0;
option LIMCOL = 0;
*option rminlp=minos;
*option mip = osl;
*option nlp=conopt2;
 option iterlim = 100000000;
 Solve model1 using mip minimizing cost;
 display cost.l;
display totNOx.l;
```

APPENDIX B

GAMS CODE

(OPTIMAL SO_2 REDUCTION STRATEGIES FOR OPG)

```
$title Optimal SO2 reduction strategies for OPG
$Ontext
*The objective of this model is to determine the best mix of power plants,
*fuels, annual capacity factor to meet the electricity demand while satisfying
*the SO2 reduction target at minimum cost.
$offtext
*
*.. list all sets
*
 Set i   plant type      /Fossil, nuclear, hydro, wind/
     F   fossil plants   /L1,L2,N1,N2,N3,N4,A1,
                    LN1, LN2, LN3,LN4,TB1,TB2/
     N   nuclear         /Pick-A,Pick-B,Darling/
     H   hydroelectric   /NW-Cari,NW-Car,NW-Mani,NW-White,NW-Silv,NW-Kaba,
                    NW-Came,NW-Pine,NW-Alex,NW-Aqua,NW-Aub,NW-WElls,
                    NW-Ray,NW-Red,NE-Kip,NE-Harm,NE-Otter,NE-Smok,
                    NE-Long,NE-Abi,NE-Sturg,NE-Sandy,NE-Wawai,NE-Ind,
                    NE-Hound,NE-Notch,NE-Mata,O-Huld,O-Joa,O-Chen,
                    O-Cala,O-Barr,O-Mount,O-Stew,O-Amp,O-Chats,O-Saund,
                    N-DeCew,N-DeCew2,N-Beck1,N-Beck2,N-Beck3,E-Mc,
                    E-Conis,E-Crys,E-Nipi,E-Bing,E-Elli,E-Ragg,E-Eddy,
                    E-Chute,E-Hanna,E-Treth,E-South,E-High,E-Mern,
                    E-Lake,E-Heal,E-Sey,E-Ran,E-Aub,E-Eugen,E-Sills,
```

```
                    E-Hag,E-Frank,E-Sid,E-Meyer/
    W   wind          /Tiverton/
    k   technology     /FGD/
    j   fuels          /coal,ng/;
*
*.. list all scalars
*
 Scalar MaxE     Electricity generated at peak time (MWe) /13000/;
 Scalar Optime   Annual operating time (hr per year) /8760/;
Scalar HydOpr   Operating cost for hydroelectric ($ per MWh) /6.75/;
 Scalar WindOpr  Operating cost for wind ($ per MWh) /5.4/;
 Scalar R        allowable electricity increment /0.01/;
Scalar nk       number of technology /1/;
*
*.. list all parameters
*
Parameters
Fmax(F)         Maximum fossil electricity generation(MWh per year)
 /L1            4323020
  L2            4323020
  N1            4292400
  N2            4292400
  N3            4292400
  N4            4292400
  A1            1883400
  LN1           4686600
  LN2           4686600
  LN3           4686600
  LN4           4686600
```

TB1 1357800

TB2 1357800/

Efossil(F) Electricity from fossil power plants in (MWh per year)

/L1 3242295

L2 3242295

N1 3219300

N2 3219300

N3 2619567

N4 2619567

A1 823000

LN1 690500

LN2 690500

LN3 690500

LN4 690500

TB1 745000

TB2 745000/

Enuclear(N) Electricity from nuclear power plants in MWh per year

/Pick-A 0

Pick-B 14300000

Darling 27600000/

Ehydro(H) Electricity from hydroelectric power plants in MWh per year

/NW-Cari 347328

NW-Car 88128

NW-Mani 373248

NW-White 352512

NW-Silv 248832

NW-Kaba 129600

NW-Came 414720

NW-Pine 720576

NW-Alex 347328

NE-Abi 1629360

NE-Sturg 26280

NE-Sandy 15768

NE-Wawai 57816

NE-Ind 15768

NE-Hound 21024

NE-Notch 1440144

NE-Mata 52560

O-Barr 925056

E-South 21024

E-High 15768

E-Mern 10512

E-Lake 10512

E-Heal 63072

E-Sey 31536

E-Ran 47304

E-Aub 10512

E-Eugen 31536

E-Sills 10512

E-Hag 21024

E-Frank 15768

E-Sid 21024

E-Meyer 21900/

Ewind(W) Electricity from wind turbine power plants in MWh per year

/Tiverton 713000/

perRed(k) reduction

```
/  FGD           0.8/;
Table  FosOpr(F,j)     Operational cost ($ per MWh)

         coal       ng
 L1      34.425     52.85
 L2      34.425     52.85
 N1      40.5       58.93
 N2      40.5       58.93
 N3      40.5       58.93
 N4      40.5       58.93
 A1      40.5       58.93
 LN1     81         81
 LN2     81         81
 LN3     81         81
 LN4     81         81
 TB1     40.5       58.93
 TB2     40.5       58.93;
parameter Rcost(F) retrofit cost (million $ per year)
/L1           2347644
 L2           2347644
 N1           2330994
 N2           2330994
 N3           2330994
 N4           2330994
 A1           1022783
 LN1          0
 LN2          0
 LN3          0
 LN4          0
```

```
 TB1          737355
 TB2          737355/;
Table  SOxemis(F,j) SO2 emission from fossil (tonne per MWh)
        coal      ng
 L1     0.00286   0.0008203
 L2     0.00286   0.0008203
 N1     0.0039    0.0008205
 LN1    0.00082   0.00082
 LN2    0.00082   0.00082
 LN3    0.00082   0.00082
 LN4    0.00082   0.00082
 TB1    0.006     0.0008209
 TB2    0.006     0.0008209;
Table  CO(F,k)
          FGD
 L1       25345866
 L2       25345866
 N1       25738304
 LN2       1160731
 LN3       1160731
 LN4       1160731
 TB1       9163500
 TB2       9163500;
 parameter NomE    Nominal electricity generated in MW;
*
 NomE     =(sum(F,Efossil(F))+sum(N,Enuclear(N))+sum(H,Ehydro(H))
        +sum(W,Ewind(W)))/(Optime);
*
 Display NomE;
```

```
*
*.. list all variables
*
 Positive Variables
Efj(F,j)  adjusted electricity generation for fossil power plants used j fuels
   v(F)   %   reduction
  gama(F,j,k)   new var for linearization;
Binary variables
   X(F,j)  fuel selection
   Y(F,k) technology selection;

*.. list all the equations
*
 Equations
   totcost total annual cost for all power generation stations ($ per year)
   totSO2  total SO2 emission (tone per year)
   totMW   total electricity generation (MWh per year)
newcon1(F,j,k)
*   newcon2(F,j,k)
   newcon3(F,j,k)
  newcon4(F,j,k)
   low(F,j)
   control(F);
    totcost.. cost =e=(sum((F,j),Efj(F,j)*FosOpr(F,j))+
                 sum(F,Rcost(F)*X(F,'ng'))+sum(N,En(N)*NucOpr)+
                 sum(H,Eh(H)*HydOpr)+sum(W,Ew(W)*WindOpr)+
                 sum((F,k),co(F,k)*y(F,k)));

   totSO2.. sum((F,j),SO2emis(F,j)*Efj(F,j))- sum((F,j,k),SO2emis(F,j)*perRed(k)
```

```
          *gama(F,j,k))=l= (1-SO2red)*SO2;

   totMW..  (sum((F,j),Efj(F,j))+sum(N,En(N))+sum(H,Eh(H))+sum(W,Ew(W)))/Optime
          =g=1.0*NomE;
te(F)..   sum(k,y(F,k))+nk*X(F,'ng')=l=nk;
swi(F)..  sum(j,X(F,j)) =e= 1;
newF(F,j).. Efj(F,j) =l= (1+R)*Efossil(F)*X(F,j);
newN(N).. En(N) =l= (1+R)*Enuclear(N);
newH(H).. Eh(H) =l= (1+R)*Ehydro(H);
newW(W).. Ew(W) =l= (1+R)*Ewind(W);
low(F,j).. Efj(F,j) =g= (L*Fmax(F))*X(F,j);
control(F).. sum(k,y(F,k))=l=1;
 cost.l = 1;
*
*.. define model name
*
 Model  model1 /all /;
*
*.. more commands
*
 option LIMROW = 0;
 option LIMCOL = 0;
*option rminlp=minos;
*option mip = osl;
*option nlp=conopt2;
 option iterlim = 100000000;
Solve model1 using mip minimizing cost;
 display cost.l;
display totSO2.l;
```

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