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Comparative assessment of energy options and strategies in Mexico until 2025

Final report of a coordinated research project 2000–2004

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FOREWORD

Mexico is undergoing significant changes in the energy sector, in particular in the electric power sector, such as the restructuring of power markets; increasing emphasis on socio-economic and environmental impacts of the electric power system; and consideration of an higher role for energy technologies compatible with sustainable development. The Mexican Government has identified the need for ensuring a sustainable pattern of production, distribution and use of energy and electricity. In this context, a comparative assessment analysis is a prerequisite for planning of the future energy and electricity facilities of the country in order to make timely decisions. It requires the identification of the expected levels of energy and electricity demand and the options that are available to meet these demands, taking special note of the national energy resources and potential imported sources. Further analysis would be needed for the optimization of the supply options to meet the demand in the most efficient and economic manner with due consideration of the environmental impacts and resource requirements.

In accordance with its mandate, the IAEA has developed a systematic approach along with a set of computer-based models for elaborating national energy strategies covering the analysis of all of the above aspects. Under its Technical Cooperation Programme, the IAEA provides assistance to its Member States to enhance national capabilities for elaborating sustainable energy development strategies and assessing the role of nuclear power and other energy options, by transferring the analytical tools along with training and providing expertise.

The present report describes the results of the Comparative Assessment of Energy Options and Strategies until 2025 study for Mexico conducted by the Secretaría de Energía, in cooperation with several national institutions, in particular the University of México. The comprehensive national analysis focuses on energy and electricity demand analysis and projections, least-cost electric system expansion analysis, energy resource allocation to power and non-power sectors and environmental analysis.

Because many of the assumptions made for the study are the result of expert consensus but have not been validated or endorsed by the Government, the present study should not be considered as the Energy and Electricity Master Plan for Mexico, but rather as a very real attempt to evaluate the possible evolution of the energy and electricity consumption under certain scenarios of socioeconomic and technical development. Likewise, the expansion plans of the electricity supply system delineated by the study should not be taken as the Government plan in this area. The findings of the study do, however, provide more insight as to the possible strategies for developing the power generating system and the necessary work to be undertaken to supplement the results of the study or to update it, if deviations are experienced in the principal hypothesis made for the study.

It should be noted that the Secretaría de Energía, Mexico, was fully responsible for all phases of the study, including the preparation of the present report. The IAEA's role was to provide overall coordination and guidance throughout the conduct of the study, and to guarantee that adequate training in the use of IAEA energy planning models was provided to the members of the national team. The IAEA officer responsible for this publication was Kee-Yung Nam of the Department of Nuclear Energy.

EDITORIAL NOTE

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1. SUMMARY

In 1997, the Government of Mexico — the ‘Secretaría de Energía’ (SENER) together with the ‘Comisión Federal de Electricidad’ (CFE) and the ‘Programa Universitario de Energía’ (PUE) of the ‘Universidad Nacional Autónoma de México’ (UNAM) requested to the International Atomic Energy Agency (IAEA) to support in conducting a technical cooperation project to provide SENER, CFE and PUE-UNAM with additional tools for expansion planning of the national electric system, which are necessary for the nation in the evaluation of sustainable growth of the generation capacity in the medium and long term.

In 1998, the IAEA approved the request as a national TC project: MEX/0/012 for the 1999–2000 programme with the title “Comparative Assessment of Energy Sources for Electricity Supply until 2025”. In 2000, the project was extended for 2 years (2001-2002) with a new title “Comparative Assessment of Energy Options and Strategies until 2025” with the objective to broaden the scope and analyze the entire energy system. The first phase of the project was performed using the DECADES software package. The report presents the results of the analysis on the comparative assessment of energy options and strategies until 2025 in entire energy system by using ENPEP (BALANCE) software package while the results of the power system analysis (first phase of the project) was treated as a special chapter of the report.

1.1. Objectives and scope of the study

The general objective of the project is to provide SENER and other Mexican institutions with modern tools that allow in conducting comprehensive comparative assessment of different energy options, supply options as well as total energy system in order to identify sustainable strategies to support the expected growth in energy and electricity demand. This is to be achieved through the acquisition and application of computer-based tools that include environment factors in the assessment of energy systems in addition to traditional economic parameters.

The objectives identified for the study were as follows:

- To project the need for primary energy in Mexico for the period through 2025 that is driven by the expected demand growth for all energy sources;
- To identify domestic supply sufficiency for major energy resources, the long term need for energy imports, and the potential for energy exports;
- To study energy infrastructure development to support the growing energy use in Mexico;
- To analyze, in view of the projected high reliance of the power system and other demand sectors on natural gas, the development of the gas sector in detail in order to identify possible supply constraints, price implications and relevant policy measures:
- To identify the potential role of renewable energy sources in the Mexican energy system;
- To quantify environmental emissions of the whole energy sector associated with the expected growth of energy consumption and possible emission mitigation measures;

- To provide, by considering several alternative scenarios, a set of possible scenarios as input to national decision-making in the energy sector.

The scope of the study includes:

- A detailed analysis of overall energy and electricity demand, and its future evolution;
- Assessment of future supply potential of indigenous energy resources - provide, by considering several alternative scenarios, a set of possible scenarios as input to national decision-making in the energy sector;
- Analysis of possibilities of import of various fuels;
- Evolution of future options for electricity generation;
- Formulation of alternative expansion plans for electric sector development; and
- Assessment of environmental impacts of future electricity generation.

1.2. Institutional setup

The study was conceived as a joint effort of Mexico and the IAEA where each part had its own clear and well-established responsibilities:

- Mexican national experts had full responsibility for the conduct of the study, including data collection and preparation, execution of the model runs, interpretation and improvement of results, etc., up to the production of final draft report of the study;

- The IAEA experts provided guidance and cooperation throughout the conduct of the study, on-the-job training of the national team, transfer of know-how and the necessary methodologies and computerized planning tools to Mexico.

The national study team included:

- SENER: Dirección General de Política y Desarrollo de Energéticos

- UNAM: Dirección General de Servicios de Cómputo Académico (both DECADES and ENPEP), Facultad de Ingeniería (both DECADES and ENPEP), and Programa Universitario de Energía (only for DECADES)

- PEMEX: Petróleos Mexicanos

- CFE: Subdirección de Programación

- IIE: Instituto de Investigaciones Eléctricas (only for DECADES)

- INE: Instituto Nacional de Ecología (only for ENPEP)

- IMP: Instituto Mexicano del Petróleo (only for ENPEP)

- CONAE: Comisión Nacional para el Ahorro de Energía (only for ENPEP)

SENER defined the objectives to be achieved, invited the relevant institutions to take part, distributed the responsibilities, and coordinated the participation of the teams setup by CFE, UNAM and IIE. SENER, UNAM and IIE collected additional background information needed for the study and the final report.

1.3. Major assumptions of the study

The main assumptions of the study are related with the future evolution of demographic, macroeconomic, social and technological factors, as well as with the national policies on energy and environment. The study period is 1999 to 2025 with 1999 as the base year.

1.3.1. Demographic assumption

The 2000-2025 medium projection population scenario of the National Population Council is used. This population scenario corresponds to annual average growth rates of 1.33% for the period 2000 to 2010, 1.02% for the period 2011 to 2020 and a 0.82% for the last five years of the projection horizon. Under this scenario, Mexico's population will increase from 98.9 million inhabitants in the year 2000 to 130.2 million inhabitants in the year 2025. Also, under this scenario the participation of the urban population will increase from 75.45% in the year 2000 to 82.3% by 2025 and a reduction of the rural population from 24.55% in the year 2000 to 17.7% by 2025.

1.3.2. Economic assumption

Every year, the Mexican energy sector prepares a set of three economic scenarios with a time span of ten years. Under these economic scenarios, identified as planning scenario, high and moderate the energy sector prepares and publish short and medium term prospective studies for the electricity, natural gas, oil derivatives and liquefied petroleum gas. However, for time spans longer than ten years there is no any official projection for the GDP and the energy demand and supply. Therefore, for the present study, it is assumed an annual GDP average growth rate of 4.5% for the period from 2002 to 2011 and a 3.5% for the period 2012 to 2025. This assumption implies that the portion from 2002 to 2011 corresponds to the planning scenario and for the rest of the time horizon it is assumed that corresponds to the GDP average growth rate of the last 25 years.

1.3.3. Energy and environmental policies

The current energy policy is oriented to provide to the population full access to the energy inputs; to guarantee the supply of energy under competitive conditions of quality and price through world class energy enterprises, public and private, operating within an adequate legal and regulatory framework with high indices of security and respect for the environment; to impulse, strongly, an efficient use of energy as well as to impulse research and development of technology; and a strong promotion and use of renewable energy sources.

Energy and environmental policies are in very close relation and are structured under the principle of sustainable development. The environmental policy, through environmental standards aim to limit the emission of pollutants and induce the intensive use of cleaner fuels, specially in the country areas considered as critical from the environmental point of view.

Energy and environmental policies promote the private inversion on the development of natural gas infrastructure for transport, storage and distribution of this fuel. They reflect the official energy policy, that is, the substitution of fuel oil by natural gas in the power and industrial sectors, the introduction of natural gas in the residential sector and to some extent in the transport sector and the reconfiguration of refineries to produce better gasoline and reduce the production of heavy residuals.

The study covers the areas of crude oil, natural gas, liquefied petroleum gas, oil products, the power sector and the entire Mexican Energy System (domestic production, imports, exports transformation, transportation, distribution and end use). Following the current energy policy and the environmental standards, there is an emphasis on natural gas to replace fuel oil as a result of the current energy policy in the power sector, public and private, to shift power generation from fuel oil to natural gas through the gas-fired combined cycle technology.

To analyze the evolution trends of the energy demand and its supply options the study took the already commented demographic and economic assumptions, the current energy and environmental policies putting emphasis on the fuel substitution and cleaner fuel strategies and develop, for the study, a reference case scenario and three alternative technological scenarios. The set up scenarios are:

- Reference case scenario, corresponding to the assumption of unlimited supply of natural gas, either domestic or imported or both;

- Alternative scenario 1 (limited gas supply scenario), As in the previous scenario all the assumptions are the same as in the reference case scenario, except that assumes a natural gas supply limitation starting 2009, which is equivalent to allow, in the power sector, a maximum of 3 natural gas-fired combined cycle unit per year. For the rest of the sectors and sub-sectors there is no a natural gas supply limitation; and,

- Alternative scenario 2 (nuclear scenario), all the assumptions demographic, economic, energy and environmental policies are identical to the ones established for the reference case scenario, the only difference lies in the power sector through the inclusion of an advance nuclear power plant with a capacity of 1,314 MW;

- Alternative scenario 3 (renewable energy scenario), this scenario focused on the introduction of additional wind and solar PV for power generation. Solar and wind technologies compete with grid electricity on a national level, including the electricity generation isolated system.

1.4. Energy and electricity demand-supply and emissions results

1.4.1. Reference case scenario results

Final energy consumption is projected to grow at an average rate of 3.8% per year, from 4,030 PJ in 1999 to 10,666 PJ by 2025. This growth is strongly fueled by the observed increase in transportation demand, which is projected to grow annually at 4.9% from 1,547 PJ in 1999 to 5,349 PJ in 2025. Transportation accounts for about 57% of the total growth in final consumption (6,636 PJ), making the transport sector the largest consumer by 2025 with over 50% of total final energy consumption (up from 38% in 1999). Industrial demand grows at 3.8% per year, leading to a slight decline in its consumption share from 39% to 37%. By 2025, transport and industry combined account for about 88% of total final energy consumption. Residential energy consumption grows relatively slowly at about 1% annually, leading to a drop in its sectoral share from 17% (1999) to 8% (2025).

The model projects refined oil products to continue to play a dominant role in Mexico's energy future. The share of oil products will remain at approximately 63% throughout the forecast period. Final natural gas consumption grows from 527 PJ to 1,764 PJ (4.8% annually), with the industrial sector accounting for about 90% of the total growth, or 1,114 PJ. The results for the manufacturing sector show energy projections for industrial energy requirements growing from the current 1,561 PJ (1999) to 3,992 PJ (2025). While fuel oil consumption actually declines from 203 PJ in 1999 to 79 PJ in 2025, consumption of other fuels increases, particularly natural gas, which is forecast to continue its penetration of the industrial market. Industrial gas consumption is expected to more than triple from about 500 PJ to 1,615 PJ. Industrial electricity demand is projected to be equally strong, also tripling from 310 PJ to 986 PJ over the forecast period.

Energy projections show a strong growth in transportation energy demand from 1,547 PJ to 5,349 PJ. Motor gasoline and diesel combined will continue to provide 90% of the total transport energy needs, with gasoline accounting for about 63%. Market shares of transportation fuels are forecast to change very little, even that there is a penetration of natural gas and liquefied petroleum gas.

Mexico's power sector is expected to undergo significant changes over the forecast period. Model results show a dramatically increasing reliance on natural gas for future system expansion. While Mexico's fuel oil units are either retired or converted to imported coal, natural gas-fired generation increases more than 25 times by 2025. As a result of this development, fuel oil generation decreases from 333 PJ or 92 terawatt-hours (TW·h) in 1999 to 39 PJ (11 TW·h) in 2025, a drop of 88%. Coal generation slightly increases in the early years from 61 PJ (17 TW·h) in 1999 to 106 PJ (29 TW·h) in 2002 and remains at this level throughout the projection period.

Natural gas generation grows at an average rate of 13.2%, from 50 PJ (14 TW·h) in 1999 to 1,265 PJ (351 TW·h) in 2025. By the end of the projection period, gas-fired generation accounts for 79% of total generation (up from 8% in 1999). Hydro and other renewables grow only modestly, leading to a gradual decline in their market share from 22% in 1999 to about 9% in 2025.

Given the strong growth in transport gasoline demand, Mexico's six refineries are expected to run into their combined capacity limits around 2005. This situation drives up the need for gasoline imports from 196 PJ (1999) to 2,276 PJ (2025), a 12-fold increase equivalent to an annual growth of 9.9%. By 2025, imports supply 66% of Mexico's gasoline consumption, up from 20% in 1999. If is decided to go through the added value route, then total refining capacity will have to be increased to 1.72 million barrels per day by 2006 up from 1.54 million barrels per day; once the completion of the reconfiguration program of refineries and with a gasoline yielding of 39 percent the total refining capacity will have to reach, in million barrels per day, the following figures: 1.94 in 2008, 2.48 in 2015, 3.16 in 2020 and 4.1 in 2025.

Projected net imports of refined petroleum products also grow. Net imports of refined oil products quickly increase from 215 PJ (1999) to 3,749 PJ (2025). By 2025, net gasoline imports amount to 2,063 PJ, or 55% of total net oil product imports. Net diesel imports are forecast to be 1,098 PJ, or 29% of total net oil product imports. Mexico's net oil export balance shows the impact of the projected growth in refined product imports. While crude oil exports are expected to continue their growth at an average rate of 0.7% per year from 3,396 PJ in 1999 to 4,520 PJ in 2025, net imports of refined products quickly increase and result in a rapid drop in net oil exports, eventually declining to 771 PJ in 2025, down from a peak of 3,848 PJ in 2005.

Total natural gas demand is forecast to grow from 799 PJ (21 billion m^3) to 4,678 PJ (127 billion m^3) over the projection period. Despite the strong growth in industrial demand (1,114 PJ total growth, or 4.6% per year), the growth in natural gas demand is heavily driven by the power sector dynamics. Natural gas consumption for power generation quickly grows from 273 PJ (7 billion m^3) in 1999 to 2,914 PJ (79 billion m^3) in 2025, equivalent to a 9.5% annual growth rate and accounting for 68% (2,641 PJ) of the total growth.

Natural gas supply model results shown a rapidly growing demand and is expected to put a strain on the domestic gas supply system. Results indicate the need to develop additional gas fields or rely on increasing gas imports, particularly after 2008 when gas fields currently under development reach their maximum output (domestic non-associated gas). At the same time, associated gas production is projected to slow down as Mexico's oil refineries reach their combined process capacity, limiting domestic crude oil production (assuming export markets cannot absorb this incremental production). The results are clearly driven by some of the oil and gas sector-specific assumptions, such as (1) total capacity of all gas processing plants remains constant at 5.034 billion ft^3 per day, (2) total capacity of all fractionating plants remains constant at 544 million ft^3 per day, (3) natural gas exports are marginal and decreasing, and (4) the ratio of crude to associated gas remains constant at the historical level.

It should be noted that according to SENER's most recent natural gas market analysis (SENER, 2002), PEMEX may substantially increase its natural gas investment program, with the goal of increasing its gas processing capacity, adding new integrated gas processing plants in the Burgos region, expanding its existing fractionating facilities in Coatzacoalcos, and upgrading its pipeline system. Under the accelerated gas development program, domestic natural gas production may increase substantially to almost 9.0 billion ft^3 per day by 2010 and thereby significantly alter the results above. This issue may be analyzed in more detail in subsequent model runs.

In addition, the study reported here did not attempt to investigate different sources of imported gas or whether it will be in the form of liquefied natural gas (LNG) and where these LNG terminals will likely be located. Undoubtedly though, if Mexico will not be able to close the projected gap between supply and demand either from additional domestic supplies or new imports, it might be exposed to price volatility similar to what has been observed in the United States recently (Greenspan, 2003) or risk disruptions in its gas markets. For a more detailed discussion and additional analysis we refer to the reader to Chapter 5 of this report.

Carbon dioxide (CO_2) emissions are forecast to grow at an average annual rate of 3.4% from 346 million metric tons (Mt) in 1999 to 828 Mt in 2025. Transportation-related emissions grow the fastest at 4.9% per year from 108 Mt to 371 Mt over the forecast period, accounting for 55% of the total growth in CO_2 emissions. By 2025, the transport sector is responsible for 45% of Mexico's CO_2 emissions (up from 31% in 1999), followed by the power sector with 193 Mt and 23% (up from 98 Mt and 28%) and industry with 147 Mt and 18% (up from 58 Mt and 17%). The 5% drop in the power sector share is related to the rapidly growing penetration of natural gas as an energy source in that sector.

National emissions of nitrogen oxides (NO_X) are projected to increase from 1.52 Mt (1999) to 4.61 Mt (2025), equivalent to a 4.4% growth rate. This development is closely linked to transport sector dynamics, as the sector contributes about 77%, or 2.38 Mt, to the overall growth in NO_X emissions. The transport share remains very high and gradually increases from 67% to 74% through the forecast period. The power sector, the second largest source, contributes 282 kilotons (kt) or about 19% in 1999 and 837 kt or about 18% in 2025.

The projected sulfur dioxide (SO_2) emissions exhibit a marked reduction of about 24% from 1999 to 2025. Emissions are forecast to initially decline from 2.35 Mt (1999) to a low of 1.21 Mt (2008) and then gradually increase again to 1.78 Mt (2025). The most notable change is the substantial drop in power sector emissions from 1.71 Mt (73% of the total) in 1999 to 0.38 Mt (22% of the total) in 2025. This drop is linked to the retirement of several of Mexico's fuel oil units burning high-sulfur fuel oil, the conversion of some of the fuel oil units to low-sulfur imported coal plants, and the projected dramatic switch to natural gas for power generation with essentially zero SO_2 emissions. The gradual increase in national SO_2 emissions after 2008 is related to the rise in industrial SO_2 emissions, which grow on average at about 3.4% from 0.44 Mt in 1999 to 1.07 Mt in 2025 as the sector continues to burn high-sulfur fuel oil. This situation causes the manufacturing sector to become the largest source of SO_2 by the end of the analysis period, contributing 60% of SO_2 emissions as compared to 19% in 1999.

The behavior of projected emissions of particulate matter (PM) is somewhat comparable with the previous discussion for SO_2 in that emissions initially decline from 323 kt (1999) to 280 kt (2003) and then increase to 484 kt (2025). However, the drop in power-sector PM emissions is not nearly enough to offset the continued emissions growth in the other sectors, therefore leading to an overall increase in PM emissions. While power sector PM emissions decline from 92 kt (29% of total, largest PM source) in 1999 to 19 kt (4% of total) in 2025, emissions in other sectors, particularly the transport and industrial sectors, continue to grow. By 2025, transportation is the largest PM source, with 208 kt or 43% of the total (up from 60 kt or 18% of the total in 1999).

1.4.2. Alternative scenario 1 (limited gas supply scenario)

The limitation of the gas supply for power generation changes the expected expansion of the power sector substantially. Starting in 2009, the expansion model selects the maximum of three combined cycle units each year instead of three to seven units per year under the Reference Case. The cumulative number of combined cycle units under the Limited Gas Scenario is 85 or 44.8 gigawatts (GW) as compared to 118 units (62.2 GW) under the Reference Case.

Respect to the effect on generation by fuel type it is noteworthy that while the gas limitation becomes effective in 2009, the generation results do not show a significant difference until 2014, the year when WASP/DECADES projects the first coal-fired units to come on-line. During 2009 to 2013, even though there are four combined cycle units less than in the Reference Case, new coal units are not needed until 2014. Starting in 2014, the model projects between four and six coal-fired units to come on-line each year, with a total of 57 coal units or 17.7 GW. Correspondingly, coal generation starts to increase quickly from 106 PJ (29 TW·h) in 2013 to 572 PJ (159 TW·h) by 2025, accounting for 36% of total power generation. The increased coal generation essentially replaces up to 470 PJ of gas-fired generation by 2025. The share of natural gas generation, therefore, reaches only about 50%, compared to 79% under the Reference Case.

The lower gas generation noticeably slows the growth in total natural gas consumption. Gas consumption is expected to grow to 3,710 PJ, down from 4,678 PJ in the Reference Case. This reduction of 968 PJ or 21% is essentially because of reduced power sector gas demand. Under the Reference Case, the power sector accounts for about 68% of total natural gas demand, but under the Limited Gas Scenario, this share is down to 53%.

In response to the reduction in gas demand for power generation, the need for new natural gas sources/imports declines. While approximately 2,690 PJ of gas has to be added/imported in the Reference Case by 2025, imports are down to 1,781 PJ under this scenario. The additional coal-fired generation cannot address the near- to intermediate-term natural gas needs. Additions/imports are substantially reduced only starting in 2014. The decrease of 909 PJ by 2025 is equivalent to a 34% reduction of natural gas imports.

At US$709.58 billion in net present value, the total economic system cost is higher than under the Reference Scenario; that is, a limitation on natural gas supply comes at an economic cost, in this case estimated to be an incremental cost of US$2.17 billion.

Not surprisingly, the shift from gas to coal comes at an environmental cost as well. Atmospheric emissions are projected to increase under the Limited Gas Scenario. For example, the changes in CO_2 and NO_X emissions compared to the Reference Case. Under the Limited Gas Scenario, power sector CO_2 emissions grow to 239 Mt, while total national emissions reach 874 Mt. This increase is about 46 million tons more than the Reference Case, equivalent to a 24% increase in power sector emissions, or 5.5% of national CO_2 emissions. Emissions of NO_X exhibit a similar behavior in that power sector emissions are forecast to reach about 990 kt by 2025, which is about 152 kt, or 18%, higher than under the Reference Case.

1.4.3. Alternative scenario 2 (nuclear scenario)

On the basis of a capital cost of US$ 2,485.4 for the nuclear candidate the expansion of the power sector does not include, in any case, this technology. Capital cost for this technology to enter into the expansion has to be lowered, for about a 48%. Under this capital cost reduction five new nuclear power plants appear in the optimal solution for the expansion of capacity. Nevertheless, in order to see the non-economic advantages of this technology, a scenario of a forced nuclear introduction was considered. This scenario includes a forced nuclear power plant of 1,356 MW and its objective was to see the non-economic advantages of this technology, such as, lower emissions or a more diversified power system, and its impact on the system cost.

Because of the large capacity of the nuclear unit, the expansion schedule is slightly affected starting in 2001 even though the unit is not coming on-line until 2012. This leads to some minor changes in generation and fuel consumption in the power sector between 2001 and 2011 in comparison with the Reference case scenario. Specifically, from 2001 up to 2011 there is an additional participation of fuel oil generation, which decreases along the years and ends by 2011; hydro also participates with an additional generation, but its participation is just during the year 2001; also there is a declining reduction in the participation of natural gas in the generation along those years. During the years 2009 to 2011 the fuel type mix in the power generation keeps the reference case structure. When the nuclear unit does come on-line, it is base-loaded into the system and generates a constant level of 34 PJ of electricity per year equivalent to 1.5 percent of total generation in 2025 as compared to 1.1 percent under the reference case scenario. The system-level analysis shows that nuclear replaces effectively base-loaded gas combined-cycle capacity and between 33-37 PJ of gas-fired generation.

As with the previous scenarios, the shift away from gas-fired generation leads directly to a reduction in natural gas imports. In this case, gas imports are cut by 63-71 PJ or 2.3 percent by 2025. At US$707.69 billion in net present value, total economic system cost is higher than under the reference scenario, that is, an incremental cost of US$273.4 million.

The minor changes in dispatch in the early years lead to small emissions increases of up to 1.2 million tons per year in 2003. But emissions are noticeable reduced starting in 2012 when the nuclear unit eventually comes on-line. For example, CO_2 emissions reductions vary between 3.6 and 4.0 million ton per year, equivalent to a 1.9 percent reduction in power sector emissions and a 0.4 percent reduction in national emissions. Total cumulative emissions reductions are 47.5 million ton of CO_2. The cost-effectiveness of nuclear technology as a GHG mitigation technology is therefore US$5.8/ton CO_2. A similar behavior is exhibited by NO_X, N_2O, SO_2 and PM emissions with a cumulative effect of 228,000 ton for NO_X emissions, 60.3 ton for N_2O, 242,790 ton for SO_2 and 14,320 ton for PM emissions along the entire period. The environmental effects and the cost reductions of this technology should be an area of future investigations.

1.4.4. Alternative scenario 3 (renewables scenario)

Because of the relative costs of wind and solar, the role of solar PV will be very limited. By 2025, solar will generate only about 1.2 PJ of electricity or 0.1 percent of total generation. This is equivalent to 195 MW of installed PV capacity. Wind, on the other side, is forecast to penetrate the market relatively rapidly. This energy source is forecasted that will account for approximately 4.9 percent of total generation, that is, 78.3 PJ by 2025. At the assumed average capacity factor of 26.2 percent, about 9,500 MW of wind capacity will be needed to generate this power. Wind will essentially replace marginal gas-fired generation by up to 93.3 PJ (2025), that is, about 19 percent more than wind electricity. The main reason for this difference is the underlying model implementation which assumes that wind generation will be more dispersed, closer to actual loads, and therefore not subject to the transmission and distribution losses in the electric grid.

Because of the change in generation mix originated by the incorporation of wind energy, the power sector will require less natural gas. This translates directly into less natural gas imports. The reduction in gas imports grows as wind generation increases and reaches approximately 180 PJ by 2025. At US$707.87 billion in net present value, total economic system cost is higher than under the reference scenario, that is, an incremental cost of US$455.64 million.

Since solar and wind replace electricity that is generated mostly by gas-fired combined cycle units limits the emission reduction potential of renewable technologies. NO_X emissions, for example, are 44,000 ton per year (2025) below projected reference case scenario levels. This is equivalent to a 5.5 percent drop in power sector emissions and a 1.0 percent decrease of total national NO_X emissions. Cumulative NO_X reductions over 2005-2025 total about 351,000 ton. The combined effect of technologies, solar PV and wind, through an accelerated penetration of renewable power generation results in CO_2 emissions that are up 10 million ton per year (2025) below the reference case scenario levels. This represents a 5.4 percent decrease in power sector CO_2 emissions and a 1.2 percent decrease of total national CO_2 emissions. The total cumulative emissions reductions in the period from 2005 to 2025 are equal 81.96 million ton. The cost-effectiveness of solar and wind as a GHG mitigation technology is therefore US$5.6/ton CO_2. This value is likely to be lower if we ignore the more expensive solar technologies and include only wind in the model. This should be an area of future investigations.

1.5. Least-cost plan for expansion of the electricity generation system

For the expansion of the power system in the near future is expected an increase in the use of oil products, mainly natural gas, because of the low investment costs of the combined cycle plants and their conversion efficiency, as well as for environmental aspects. This expansion policy aims to minimize the dependency of imported sources of energy, for example, coal, if dual plants were installed. Also, in the middle term, some hydro projects are considered as expansion candidates, despite of their high investment costs, but with the purpose of an increasing level in the use of the hydro resources, to diversify the system generation expansion and to take into account environmental aspects. The expansion of the electric system was carried out taking into account these considerations and the technical and economic parameters explained in Chapter 2.

Table 1.1. Summary results of the power system expansion analysis (system configuration at the end of the study period)

	Description	Nuclear	Dual	Combined cycle	Gas turbine	Hydro A	Hydro B	Objective function
		1,356 MW	350 MW	546 MW	179 MW			US$ million
	Base case	0	0	118	6	3	2	53,124.6
A1	**High demand** (growth 6%)	0	0	157	27	3	2	60,232.1
B1	**Low nuclear cost** (-48% investment cost)	5	0	105	9	3	2	53,325.4
B2	**Forced nuclear** (year 2012)	1	0	115	9	3	2	53,530.7
C1	**Slightly higher fuel scenario**	0	0	119	4	3	2	57,510.7
C2	**High scenario for gas** (4 $/tcf)	0	0	110	30	3	2	61,907.2
C3	**Medium term increment gas price** (2.88, 12, 4 $/tcf)	0	159	26	4	3	2	76,269.1
D1	**Limitation of combined cycle** (3 units per year)	0	57	85	4	3	2	54,266.1
D2	**Limited natural gas supply** (gas supply is limited to the 2010 amount)	0	122	45	4	3	2	55,870.5
E1	**12% discount rate**	0	0	118	5	3	2	44,714.6
E2	**8% discount rate**	0	0	118	8	3	2	64,346.5
F1	**Increased reliability** (1 day/year, ENSC = 13 $/kWh)	0	0	119	15	3	2	53,230.1
F2	**Decreased reliability** (5 day/year, ENSC = 0.55 $/kWh)	0	0	116	4	3	2	53,089.2
F3	**Decreased reserve margin** (ENSC = 0.25 $/kWh)	0	0	113	4	3	2	53,056.7

The costs reported in this table differ from the discounted costs given in the text, because the objective function in the table includes the salvage values and the cost of unserved energy.

Under this considerations, besides five hydro projects with a total capacity of 2,539 MW and two 50 MW geothermal projects, four thermal technologies were consider as candidates for the expansion of the electric system, namely: natural gas combined cycle (546 MW), dual fuel with desulphurization (350 MW), natural gas simple cycle (179 MW) and advanced nuclear water reactors (1,356 MW).

The main reason for the choosing of these alternatives for the expansion of the Mexican Electric System is the economic factor. However, other aspects become also important for the development of the power plant expansion of the electric system. Aspects, such as environmental impacts (e.g. lower CO_2 emissions with nuclear plants), oil derivatives and natural gas prices and energy supply diversification have an effect on the economic factor and were considered in the analysis.

DECPAC module (WASP-III Plus version) of DECADES has been used to carry out the analysis of the base case and several different alternative plans for the future expansion of the power system over 27 years; the planning period is from 1999 to 2025.

Table 6.2 shows the results for the reference case and 13 alternatives evaluated in the system level analysis. The reference case optimal solution until 2025 for the expansion of the electric system requires the installation of 118 natural gas -fired combined cycle units (64,428 MW), 6 gas-fired turbines (1,074 MW), as well as 2,539 MW of hydro projects, with a total discounted cost of US$54.4 billion, US$9.5 billion for capacity additions and US$44.9 billion for operation and maintenance.

The cases that have the higher impact with respect to the reference case are those of higher escalation of natural gas prices. In alternative C_1 (slightly higher fuel prices), the number and type of units to be installed are essentially the same as in the base case, because it requires 119 gas-fired combined cycle units (64,974 MW) and 4 gas-fired turbine units (716 MW). The total discounted cost increases to US$58.8 billion, US$ 9.7 billion for investment in capacity additions and US$49.1 billion for operation and maintenance.

In alternative C_2 (high natural gas price), 110 gas-fired combined cycle units (60,060 MW) and 30 gas-fired turbine units (5,370 MW) are required, but the total discounted cost increases significantly to US$63.2 billion, US$8.9 billion for investment in capacity additions and US$54.3 billion for operation and maintenance.

For alternative C_3 (medium term increase in the gas price) the mix of new units changes considerably compared to the reference case. Only 26 gas-fired combined cycle units (14,196 MW) and 4 gas-fired turbine units (716 MW) are required, but they must be complemented by 159 coal-fired dual units (55,650 MW) with a very substantial increase in the total discounted cost, US$79.6 billion of which US$27.7 billion are for capacity additions and US$52.0 for operation and maintenance.

With regard to the impact of the natural gas supply limitation scenario, alternative D_1 (limitation on number per year of new gas-fired combined cycle) the number of gas-fired combined cycle units required is limited to 85 (46,410 MW), the number of gas-fired turbine units is reduced to 4 (716 MW), but the system expansion requires the construction of 57 coal-fired dual units (19,950 MW). The total discounted cost increases to US$56.5 billion, US$12.0 billion for investment in capacity additions and US$44.5 billion for operation and maintenance.

On the other hand, under the natural gas supply limitation scenario, alternative D_2 (limited gas supply starting 2010), the number of gas-fired combined cycle and gas-fired turbine units are restricted to 45 (24,570 MW) and 4 (716 MW) units, respectively, but the number of coal-fired dual units is increased to 122 (42,700 MW). The total discounted cost increases to

US$59.2 billion; the investment cost increases to US$15.5 and the operation and maintenance cost is reduces to US$43.8 billion.

Table 1.2. Emissions from the alternatives of the power system expansion at the last year of the study period.

	Description	CO_2	SO_X	NO_X	PM
		million ton	thousand ton	thousand ton	thousand ton
	Base case	196	344	338	16.3
A1	**High demand**	251	378	409	18.3
	(growth 6%)				
B1	**Low nuclear cost**	177	357	315	17.0
	(-48% investment cost)				
B2	**Forced nuclear**	192	353	334	16.8
	(year 2012)				
C1	**Slightly higher fuel scenario**	195	326	336	15.2
C2	**High scenario for gas**	205	845	361	46.4
	(4 $/tcf)				
C3	**Medium term increment gas price**	323	630	1,192	58.3
	(2.88, 12, 4 $/tcf)				
D1	**Limitation of combined cycle**	241	444	646	31.2
	(3 units per year)				
D2	**Limited natural gas supply**	293	590	999	50.2
	(gas supply is limited to the 2010 amount)				
E1	**12% discount rate**	196	344	338	16.3
E2	**8% discount rate**	196	344	338	16.2
F1	**Increased reliability**	195	327	336	15.2
	(1 day/year, ENSC = 13 $/kWh)				
F2	**Decreased reliability**	197	395	341	19.3
	(5 day/year, ENSC = 0.55 $/kWh)				
F3	**Decreased reserve margin**	198	477	346	24.3
	(ENSC = 0.25 $/kWh)				

ENSC = cost of unserved energy

The impact of lower investment cost for nuclear units, alternative B_1, introduces 5 new nuclear units (6,780 MW) in the expansion of the electric system, 105 gas-fired combined cycle units, 9 gas-fired turbine units and the already mentioned hydro projects. The total discounted cost is US$54.9 billion, US$10.4 billion for investment in capacity additions and US$44.6 for operation and maintenance. In comparison with the reference case the total discounted cost increases by US$500 million.

For alternative B_2, one forced nuclear unit, 115 gas-fired combined cycle units, 9 gas-fired turbine units and the 5 hydro projects the total discount cost is very similar to the total discounted cost for the reference case.

The impact of the discount rate value on the expansion results are not significant in the type and number of units to be installed. They are almost the same as in the reference case, the difference lies in the number of gas-fired turbine units (for a discount rate of 12%, 5 gas-fired turbine units instead the 6 units of the reference case; for a discount rate of 8%, 8 gas-fired turbine units instead the 6 units of the reference). However, in alternative E_1, 12% discount rate, the total discounted cost decreases, substantially, in comparison with the reference case to US$45.5 billion, US$8.0 for capacity additions and US$37.5 for operation and maintenance.

For all the considered cases, environmental emissions from the power sector were calculated and are shown in Table 6.3. It becomes clear the benefits of the nuclear option from the CO_2 emission point of view and for almost all the pollutants.

1.6. Others

After the system level analysis of the generation expansion scenarios is concluded, and a number of interesting expansion scenarios is selected, it is necessary to implement a decision analysis methodology in order to determine the optimal solutions for the system. In general terms the decision-making problem is composed of three elements: 1) an objective or goal; 2) a number of criteria to evaluate this objective and 3) a number of alternatives to select. In such a problem it is necessary to have measures or indicators that would show how good or how bad are the alternatives in achieving these objectives. Such measures are called criteria and the problems are called multiple criteria decision analysis problems. The number of objectives and the number of criteria may not and often do not coincide. Each criterion has its units of measurement and its direction. The difficulty of choosing the best alternative in this type of problems is that normally there is no single alternative that is the best for all criteria.

Several approaches have been designed to cope with such problems. For the present study it was selected the interval decision methodology, incorporated in the Decision Analysis Module (DAM module) of the DECADES package. The detailed description and application of the DAM module is discussed in Chapter 6.

Table 1.3 shows the structure of the decision-making analysis. All the alternatives chosen have similar total discounted costs that add up to the objective function, which include the investments, salvage value at the end of the unit's useful life, operation and maintenance expenditures and cost of energy not served.

The reference case and five alternatives chosen are compared from the point of view of cost, emissions to the environment and a third parameter called the Stirling diversity index, also discussed in Chapter 6 and Appendix I. For the comparison to be meaningful, a range of costs was assigned to the emissions, taken from the ExternE study for Spain and Italy, adjusted to the GDP per capita of Mexico to reflect the difference in economic development (see Chapter 6). The Stirling diversity index was estimated as a wide range of values, US$1,000–50,000 million per unit.

Table 1.3 Structure of the decision making-making analysis

Alternatives/Criteria	Cost (PV) US$ million	CO2 million ton/PV	SOX million ton/PV	NOX million ton/PV	PM million ton/PV	Stirling index
Base case	53,124.6	3,381/1,064	20.46/10.61	7.18/2.53	1.13/0.61	0.904
B2 Forced nuclear	53,530.7	3,331/1,056	20.43/10.60	7.11/2.51	1.13/0.61	0.955
D1 Limitation of combined cycle	54,266.1	3,686/1,105	22.79/11.09	9.10/2.77	1.33/0.65	1.213
D2 Limited natural gas supply	55,870.5	4,064/1,154	23.80/11.20	11.64/3.10	1.46/0.66	1.248
F1 Increased reliability	53,230.1	3,369/1,062	19.93/10.52	7.14/2.52	1.10/0.61	0.890
F2 Decreased reliability	53,089.2	3,389/1,065	20.88/10.66	7.21/2.53	1.16/0.62	0.914

Considering only the usual system costs, Alternative F_2 (decreased reliability) followed by the reference case are the best solutions. If the costs of emissions are included, then at the higher range of cost of CO_2 emissions alternative B_2 (forced nuclear) and alternative F_1 (increased reliability) are the best solutions. Finally, if the Stirling diversity index is included in the analysis, then the cases with the highest value of the index are potentially optimal such as alternative D_2 (natural gas supply limitation), followed by alternative D_1 (limited number of gas-fired combined cycle units) and alternative B_2 (forced nuclear).

1.7. Conclusions

For all the analyzed scenarios the general conclusion indicates that Mexico will continue to rely heavily on fossil fuel for its energy trade and final energy consumption. Crude oil production will have to increase from 2.91 million barrels per day in 1999 to 3.78 million barrels per day by 2025. To keep the proper balance between production and proven reserves of crude oil and gas important investment in oil and gas exploration and production will have to be allocated. In order to reduce the dependency of imported oil products and natural gas the refining and gas processing capacities will have to be increased. Refining capacity will have to be increased from 1.54 million barrels per day in 1999 to 4.07 million barrels per day by 2025. To keep the proper balance between supply and consumption of natural gas with an important participation of domestic production, starting 2010, it will be necessary to incorporate more non-associated gas fields to production. In order to handle the primary gas production and the imports, natural gas infrastructure (production wells, gas pipelines, processing centers and distribution) will have to grow at an accelerated level.

Natural gas will be the primary choice for power system expansion and generation leading to a near term and long term need for additional gas imports (or accelerated expansion of natural gas domestic production). Under restricted conditions of financial sources natural gas and environmental policies should be review and fuel oil generation incorporated and analyzed their benefits in the short and medium term.

In the case of the nuclear option specific studies will have to carry out. Special attention has to be paid to the total cost of the expansion scenarios including the internalization of the environmental externalities of the whole energy chain and looking for the total cost at which the nuclear option becomes competitive.

An additional conclusion derived from the study is the need for SENER, CFE and UNAM to analyze with much more detail the issue of economic, environmental, social and political impact of the diversification of the mix of technologies for the long term expansion of the electric system in Mexico as well as for the entire Mexican energy system. This conclusion arises from the vulnerability that exists in case of limitations in the supply of natural gas or in the increase of their prices.

In the context of diversification it can be recommended that SENER, CFE and UNAM study the possible economic and environmental benefits of incorporating more wind, solar and geothermal units as candidate technologies for the expansion of the electric system and alternative technologies in the other sectors of the Mexican energy system. The results of these studies could indicate the need to incorporate wind and solar technologies in the COPAR document of CFE as well as in the outlook of the electric sector published by SENER ([5] del Sector Eléctrico). On the other hand, at the level of the integrated Mexican energy system the need for the study of the possible economic and environmental costs and benefits of incorporating new technologies for transportation, industrial process and final end uses in the different sector of the energy system.

From the point of view of the model's structure and it use, there is also a need to increase energy data availability and quality in the all the sectors. This is strictly necessary in order to improve the results of the model and the benefits of its use. Significant efforts are to be done in the characterization of the different conversion processes used in the industrial and other sectors. It is urgent to improve availability and reliability of the information related to energy efficiency, costs, final end uses, input/output ratios for different processes and final end uses, etc. This could be achieved by providing information, sources of information, accessibility to the information and a compromise of confidential and correct use of the provided information.

1.8. Structure of full report

The full report of project MEX/0/012 consists of this summary, five chapters and several Appendixes. They were written by different participants in the project and were compiled under the direction and supervision of SENER, UNAM and IAEA.

The first chapter summarizes the objectives and scope of the study, assumptions for the analysis as well as the results of the study. Chapter two incorporates reference information useful to readers of the report not familiar with Mexico and its energy sector. Chapter three describes the methodologies, which were used in the study. Chapter four summarizes the result of the WASP (/DECADES) study on power system alternatives of expansion with consideration of the environmental impacts related to different energy technologies. Chapters five and six refer to the conducted study on comparative assessment of energy options and strategies for the total energy system in Mexico by using ENPEP software package and MODEMA. Chapter five explains the scope of the study and the configuration of the entire energy network while Chapter six deals with its main results. Chapter seven, as a special chapter, refers to the results of the DECADES study, namely system level analysis and decision-making analysis. The last chapter contains conclusion and recommendations. The Appendixes contain additional information related to the tasks of the project.

2. ECONOMY AND ENERGY

2.1. Background information

Mexico is located in the northern part of the American Continent, together with Canada and United States; but often grouped into the Latin America region. Mexico is adjacent in its northern part with the United States and southeastern part with Guatemala and Belize. The total area accounts 1,964,375 km² - 1,959,248 km² of continental surface and 5,127 km² of the insular surface.

Mexico's total population in 2000 was 98.9 million, ranked the eleventh position in the world with the annual average growth rate of 1.7% between 1990 and 2000.

Over the past few years, Mexico's economy showed slow growth and in 1999, Gross Domestic Product (GDP) accounted to 483.7 billion US$, where the agricultural sector represented 5.0% of the percentage share, while industry and service sector represented 28.2% and 66.8%, respectively. Within the industry sector, manufacturing accounted 74.7%. The energy sector has played a key role in Mexican economic development by providing sufficient, reliable and low cost industrial inputs, as well as goods and services for consumers. Throughout the years the energy sector has also consolidated itself as a very important foreign currency generator.

2.2. Energy resources

Mexico is rich in natural energy resources with crude oil, natural gas, coal, uranium and renewable energy sources such as hydro, geothermal, wind and others. Of these, crude oil and gas are, by all means, the most important in energy sources where Mexico ranks the seventh and twenty-first position in the world for proven crude oil and natural gas reserves, respectively.

2.2.1. Crude oil reserves

Mexico's total oil reserves (proved, probable and possible), in terms of crude oil, gas liquids and expressed in barrels of oil equivalent, are shown in Table 2.1.

Total oil reserves are located in four regions, two marine regions and two onshore regions. Marine regions are located in the Gulf of Mexico and the onshore regions are located in the south and north parts of the continental land.

In the beginning of year 2002, marine regions (Northeastern and Southwestern) represent 52.2% of the total crude oil reserves, while onshore regions (Southern and Northern regions) the remaining 47.8%. In terms of total gas liquids reserves the splitting between these regions are 39.25 and 60.75%, respectively.

Crude oil reserves of the Northeastern Marine and North Regions consist of heavy[1] and light[2] oil. Oil from the Southwestern Marine Region consists of light oil and from the South Region are heavy, light and lighter[3] oil.

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[1] Crude oil with American Petroleum Institute Classification (API) density less or equal than 27° - mainly produced in the Campeche Sound.
[2] Crude oil with API density between 27° and 38° - produced in the Campeche Sound and other areas.
[3] Crude oil with API density higher than 38° - produced in the Mesozoic areas of the Southern Region.

Table 2.1. Crude oil and gas liquids reserves

	1999		2000		2001		2002	
	Crude oil	Gas Liquids[b]	Crude oil	Gas Liquids[b]	Crude oil	Gas Liquids[b]	Crude oil	Gas Liquids[b]
	million bep	*million bep*	*million bep*	*million bep*	*million bep*	*million bep*	*million bep*	*million bep*
Total[a]	**41 064.0**	**5 874.7**	**41 495.3**	**6 036.3**	**39 917.8**	**5 573.8**	**38 286.1**	**4 926.6**
Northeastern Marine Region	17 917.6	1 113.8	18 346.8	1 271.8	17 359.3	1 243.0	16 593.7	1 171.9
Southwestern Marine Region	3 374.1	480.2	3 811.1	782.1	3 540.0	877.6	3 389.8	762.0
Southern Region	6 047.7	2 387.7	5 653.1	1 962.7	5 428.4	1 787.0	4 889.2	1 475.6
Northern Region	13 724.6	1 893.0	13 684.3	2 019.7	13 590.1	1 666.2	13 413.4	1 517.1
Proved[a]	**24 700.2**	**3 698.8**	**24 631.3**	**3 628.7**	**23 660.3**	**3 280.6**	**22 419.1**	**3 005.8**
Northeastern Marine Region	11 936.1	844.6	11 721.7	905.4	11 048.0	871.8	10 272.4	796.1
Southwestern Marine Region	1 366.1	203.4	1 563.8	290.9	1 451.2	317.4	1 383.9	286.2
Southern Region	4 414.0	1 729.9	4 317.4	1 455.7	4 158.5	1 286.7	3 864.5	1 155.3
Northern Region	6 984.0	920.9	7 028.4	976.7	7 002.6	804.7	6 898.3	768.2
Probable[a]	**8 885.0**	**1 055.7**	**9 035.0**	**1 073.2**	**8 982.4**	**1 054.6**	**8 930.4**	**948.4**
Northeastern Marine Region	4 514.6	194.5	4 650.8	235.1	4 553.8	246.6	4 597.0	252.6
Southwestern Marine Region	804.4	103.1	785.2	159.7	798.9	181.7	843.1	156.6
Southern Region	703.9	339.3	748.3	235.2	774.2	271.7	664.3	218.5
Northern Region	2 862.1	418.8	2 850.7	443.2	2 855.5	354.6	2 826.0	320.7
Possible[a]	**7 478.8**	**1 120.2**	**7 829.0**	**1 334.4**	**7 275.1**	**1 238.7**	**6 936.6**	**972.6**
Northeastern Marine Region	1 466.9	74.7	1 974.3	131.3	1 757.5	124.7	1 724.3	123.2
Southwestern Marine Region	1 203.6	173.7	1 462.1	331.5	1 289.9	378.5	1 162.8	319.2
Southern Region	929.8	318.5	587.4	271.8	495.7	228.6	360.4	101.9
Northern Region	3 878.5	553.3	3 805.2	599.8	3 732.0	506.9	3 689.1	428.3

a) Based on reserves as of beginning of the year and production of the previous year
b) Includes condensates
Source: JQM, prepared on the basis of *PEMEX Statistical Yearbook, 1999-2002*

2.2.2. Natural gas reserves

Natural gas resources can be present in natural gas (non-associated gas) or associated to oil. In Mexico, natural gas resources are located both onshore and offshore. The total natural gas reserves, in terms of associated and non-associated gas (proved, probable and possible), are shown in Table 2.2. In 2002, associated gas represents 79.66% of the total natural gas reserves while non-associated natural gas represents the remaining 20.34%. In terms of the amount of associated gas by region, Northern and Southern onshore region cover about 80%, while

Northeastern marine region and Southwestern marine region cover the rest. In case of non-associated gas, the regional distribution is quite similar, however, in the Northeastern marine region, the reserves of non-associated natural gas could not be found.

In terms of dry natural gas, Table 2.3 shows the distribution of the reserves in the four regions. This explains the importance of the onshore Northern and Southern regions for the country's gas supply.

Table 2.2. Natural gas reserves (associated and non-associated)

	1999		2000		2001		2002	
	Natural gas		Natural gas		Natural gas		Natural gas	
	Associated	Non-associated	Associated	Non-associated	Associated	Non-associated	Associated	Non-associated
	billion cf	billion cf	billion cf	billion cf	billion cf	billion cf	billion cf	billion cf
Total	**64 271.6**	**16 766.9**	**62 049.6**	**16 237.0**	**60 010.6**	**16 424.5**	**55 049.1**	**14 055.8**
Northeastern Marine Region	8 311.9	0.0	8 897.9	0.0	8 161.4	0.0	7 916.5	0.0
Southwestern Marine Region	4 584.1	1 182.2	4 979.3	1 935.8	4 663.7	1 935.8	3 982.5	1 944.2
Southern Region	12 330.3	7 297.4	11 319.4	6 979.7	10 865.9	6 825.0	9 725.6	5 738.1
Northern Region	39 045.3	8 287.3	36 853.0	7 321.5	36 319.6	7 663.7	33 424.5	6 373.5
Proved	**36 683.4**	**8 379.4**	**35 460.3**	**7 707.5**	**34 397.4**	**6 985.6**	**32 256.6**	**6 692.9**
Northeastern Marine Region	6 303.3	0.0	6 337.0	0.0	5 719.9	0.0	5 376.1	0.0
Southwestern Marine Region	1 922.5	627.4	2 157.6	448.2	1 998.1	448.2	1 813.3	468.5
Southern Region	9 304.8	4 622.2	8 917.7	4 444.2	8 730.1	3 668.5	7 819.2	3 802.1
Northern Region	19 152.8	3 129.8	18 048.0	2 815.1	17 949.3	2 868.9	17 248.0	2 422.3
Probable	**12 050.0**	**3 596.7**	**11 923.6**	**2 961.5**	**11 670.8**	**3 638.1**	**10 856.1**	**3 000.6**
Northeastern Marine Region	1 451.6	0.0	1 639.7	0.0	1 624.9	0.0	1 713.8	0.0
Southwestern Marine Region	1 020.3	203.1	1 025.5	376.1	974.4	376.1	864.3	340.2
Southern Region	1 331.6	1 532.8	1 170.4	1 293.7	1 189.3	1 727.4	1 334.7	1 242.0
Northern Region	8 246.5	1 860.8	8 088.0	1 291.7	7 882.2	1 534.6	6 943.3	1 418.4
Possible	**15 538.2**	**4 790.8**	**14 665.7**	**5 568.0**	**13 942.4**	**5 800.8**	**11 936.4**	**4 362.3**
Northeastern Marine Region	557.0	0.0	921.2	0.0	816.6	0.0	826.6	0.0
Southwestern Marine Region	1 641.3	351.7	1 796.2	1 111.5	1 691.2	1 111.5	1 304.9	1 135.5
Southern Region	1 693.9	1 142.4	1 231.3	1 241.8	946.5	1 429.1	571.7	694.0
Northern Region	11 646.0	3 296.7	10 717.0	3 214.7	10 488.1	3 260.2	9 233.2	2 532.8

Source: JQM, prepared on the basis of *PEMEX Statistical Yearbook, 1999-2002 and PEMEX: Memoria de Labores, 1999-2001*

2.2.3. *Coal reserves*

In Mexico, coal basins can be classified by three periods of time. Those of greater antiquity, from 170 to 200 million years, are located in the states of Oaxaca and Sonora. Others with antiquity of 70 to 170 million years are in the states of Coahuila, Chihuahua and Sonora. Mexico also has coal basins with the age of 40 to 50 million years that are located in the states of Nuevo León and Tamaulipas.

Table 2.3. Dry natural gas reserves

	1999	2000	2001	2002
	Dry gas	**Dry gas**	**Dry gas**	**Dry gas**
	billion cf	*billion cf*	*billion cf*	*billion cf*
Total[a]	**56 183.1**	**55 507.3**	**55 515.1**	**50 648.4**
Northeastern Marine Region	3 407.9	4 714.7	4 408.5	4 283.6
Southwestern Marine Region	3 266.8	3 891.1	4 082.6	3 565.3
Southern Region	11 841.8	12 579.7	12 379.7	11 006.8
Northern Region	37 666.6	34 321.8	34 644.3	31 792.7
Proved[a]	**30 064.1**	**30 393.5**	**29 505.4**	**28 150.9**
Northeastern Marine Region	2 584.4	3 308.0	3 063.2	2 884.8
Southwestern Marine Region	1 376.1	1 446.9	1 476.1	1 345.1
Southern Region	8 230.5	9 236.7	8 654.7	8 334.7
Northern Region	17 873.1	16 401.9	16 311.4	15 586.3
Probable[a]	**11 253.1**	**10 572.1**	**11 293.8**	**10 317.0**
Northeastern Marine Region	595.1	929.8	911.9	961.9
Southwestern Marine Region	686.6	795.0	845.4	724.6
Southern Region	1 795.6	1 578.6	2 136.7	1 842.1
Northern Region	8 175.8	7 268.7	7 399.8	6 788.4
Possible[a]	**14 865.9**	**14 541.7**	**14 715.9**	**12 180.5**
Northeastern Marine Region	228.4	476.9	433.4	436.9
Southwestern Marine Region	1 204.1	1 649.2	1 761.1	1 495.6
Southern Region	1 815.7	1 764.4	1 588.3	830.0
Northern Region	11 617.7	10 651.2	10 933.1	9 418.0

a) Based on reserves as of beginning of the year and production of the previous year

Source: JQM, prepared on the basis of *PEMEX Statistical Yearbook, 1999-2002*

Different efforts have been developed for exploring the country to evaluate the national coal reserves. Based on them, the reserves are estimated to be 662.9 million of tons, distributed in four main coal basins as described in Table 2.4. Most of the thermal coal reserves are in the basin Villa de Fuentes-Río Escondido. This basin is located in the northeast region of the state of Coahuila[4] and has been exploited through several opencast mines and underground mines. The reserves are 64.9 million tons of opencast mines and 470.5 million tons of underground mines. The coal of this basin is classified as a bituminous vitrain coal type.

Table 2.4. Coal reserves by basin

Basin	Location (state)	million ton
Villa de Fuentes-Río Escondido	Coahuila	535.4
Colombia-San Ignacio	Nuevo León-Tamaulipas	91.7
La Mixteca	Oaxaca	31.0
Barranca	Sonora	4.8
Total		662.9

Source: Programa de Desarrollo y Reestructuración del Sector de la Energía , 1995-2000, Poder Ejecutivo Federal, Secretaría de Energía, 1995, pp. 14-15.

The Colombia-San Ignacio coal basin, second in importance at national level, is located in north end of the state of Nuevo León and northwest part of the state of Tamaulipas. The basin has a surface of 2,500 km^2. The basin has been divided in three exploration zones: Colombia, Jarita and San Ignacio. Colombia and Jarita zones have 51 million tons that can be exploited using opencast mines and 40.7 million tons using underground mines. The San Ignacio zone presents little possibilities of containing deposits that could be exploited in an economic way. Petrographically, the coals of these deposits are classified within the rank of vitric lignite to sapropelic lignite. If CFE classification is used, the coals of these basins are classified as bright sapropelic lignite to bright vitric lignite.

2.2.4. Uranium reserves

There are differences between the official and non-official data of the reserve and resource figures of uranium. This lies on the lack of an accurate definition of the adopted concepts to classify the resources. Up to the date, it is known the existence of around 14,500 tons of uranium, of which is estimated that only 10,600 tons could be extracted. Currently, there is neither planned exploration activity nor a future development program on the exploitation of uranium reserves in Mexico.

According to the Programa Nacional de Energéticos 1984-1988 and data of January 1981, the Mexican uranium reserves by state are shown in Table 2.5.

2.2.5. Hydro-electric resources

The national hydroelectric potential is estimated to 53,000 MW[5]. The estimated potential for power stations with installed capacities smaller than 10 MW is 3,250 MW and a generation of

[4] CFE, El Carbón en la generación de energía eléctrica en México, Abril 1992
[5] http://www.conae.gob.mx/renovables/minihidr.htm

479 GW·h per year. In order to promote exploitation of these resources, an important task is to carry out the study of the technical and economic feasibility to develop projects in the different identified sites.

The Comisión Federal de Electricidad (CFE) has carried out several studies to identify the best opportunities for the development of the Mexican hydroelectric potential. Table 2.6 shows the results of these studies. On the basis of the CFE studies there is a set of identified specific important hydroelectric projects that are listed in Table 2.7.

Table 2.5. Uranium reserves

State	Reserves (ton)
Chihuahua	2 078.1
Sonora	889.6
Durango	258.8
Nuevo León	3 477.0
Others	3 896.5
Total	10 600.0

Source: Castañeda Pérez, M., *La Producción de Uranio en México,* Quintanilla, J. (Ed), Programa Universitario de Energía, UNAM, 1986, p. 146, Table A.19.

These projects are considered as possible candidates for the definition of the expansion program of the power sector. As possible candidates for the definition of the expansion program of the power sector, CFE, as well as, private investors can carry out its development, under the conditions of the actual electric law.

Considering its river basins, Figure 2.1[6] shows the potential of hydroelectric regions that Mexico had in 1978. As it can be seen in the figure, the Grijalva-Usumacinta river basin had the greater percentage of hydroelectric potential.

2.2.6. Geothermal resources

The study of the geothermal resources of Mexico started in the fifties with the exploration of the geothermal zones of Ixtlán de los Hervores, Pathé and Cerro Prieto. At present[7], there exist 1380 geothermal locations, with different levels of detailed knowledge (808 correspond to thermal springs, 526 hot water wells, 25 fumaroles, 6 mud volcanoes, 11 throbbing places and 4 hot soils. Also, is known that several of these geothermal locations have a common source, therefore, the number of geothermal zones is reduced to 545 in which the CFE has carried out 41 pre-feasibility studies. The result of these studies has been the identification of

[6] Potencial Hidroeléctrico Nacional, CFE, 1978, p. 23

[7] Torres, V., *et al,* Geotermia en México, Documentos de Análisis y Prospectiva del Programa Universitario de Energía, J. Quintanilla (Ed.), Programa Universitario de Energía, UNAM, México, Diciembre 1993.

21 zones with the possibility of extracting fluids of high enthalpy. Additionally, in 21 thermal zones have been detected low enthalpy fluids.

Table 2.7. Hydroelectric projects with finished feasibility studies or in process

Area	Project	Location	Number of units × unit's power[6]	Total capacity[6]	Annual average generation	Study level
				MW	*GW·h*	
Occidental	Equipamiento San Rafael	Nayarit	2 × 12	23	145	D
Occidental	El Cajón	Nayarit	2 × 340	680	1 207	D
Noroeste	PR Amata[1]	Sinaloa	-	Regulating	36	D
Occidental	Agua Prieta (Captaciones Osorio-San Andrés)[2]	Jalisco	-	-	80	D
Oriental	Nuevo Tuxpango	Veracruz	2 × 20	40	251	D
Oriental	Atexcaco[3]	Puebla	3 × 40	120	336	FT
Central	La Parota	Guerrero	3 × 255	765	1 332	FT
Oriental	San Juan Tetelcingo	Guerrero	3 × 203	609	1 312	FT
Baja California	Tecate (convencional)	Baja California	2 × 30	60	154	FT
Oriental	Xúchiles	Veracruz	3 × 80	240	691	FT
Oriental	Boca del Cerro (bulbo)	Tabasco	8 × 70	560	2 745	FT
Central	Tepoa	Guerrero	3 × 110	330	767	FT
Oriental	Copainalá (bulbo)[4]	Chiapas	6 × 35	210	420	FT
Occidental	San Francisco	Jalisco	2 × 139	278	609	FT
Occidental	Arroyo Hondo	Jalisco	2 × 67	133	292	F
Noroeste	Soyopa	Sonora	2 × 23	46	167	F
Occidental	Ampliación Santa Rosa[5]	Jalisco	1 × 49	49	74	F
Noroeste	El Mezquite	Sonora	2 × 20	40	145	F
Noroeste	PAEB Monterrey	Nuevo León	2 × 100	200	292	F
Oriental	Omitlán	Guerrero	2 × 115	230	789	F
Baja California	PAEB El Descanso	Baja California	4 × 250	1 000	2 087	F
Noroeste	Madera	Chihuahua	2 × 138	276	726	F
Occidental	Pozolillo	Nayarit	2 × 187	374	819	F
Oriental	Ixtayuca	Oaxaca	2 × 270	540	1 596	F
Oriental	Las Minas II	Veracruz	2 × 7	15	126	D
Total				6 818	17 197	

1 Regulating reservoir associated with the generation plant Prof. Raúl J. Marshal (El Comedero). No installation of additional power capacity. Its construction implies change in the energy quality of the power station (134.9) GW·h) and additional generation of 36 GW·h.
2 More power will not be installed, and the generation is referring to the increase of the volume of flow in 0.83 m3/s.

3 The private sector has interest to develop this project under the self-supplying scheme.

4 It considers future conditions of the hydroelectric generation plant Ing. Manuel Moreno Torres (Chicoasén) where total capacity will be increased from 1,500 to 2,400 MW.

5 The power and generation correspond to the expansion of this generation plant.

6 Power at the output of the power generator.

F = Feasibility FT = Finished feasibility D = Design

Source: [5] page 114

The geothermal fields of Cerro Prieto (Baja California), Los Azufres (Michoacán), Los Humeros (Puebla) and La Primavera (Jalisco) field represent a proved reserves[8] potential of 1,400 MW. Onshore probable reserves increase this figure up to 4,600 MW considering the

[8] Hernández, J. L., Small Geothermal Schemes: The Mexican Experience, Geothermics, Vol. 7, No 2-3, 1988, pp. 303–309.

extractable volumes of thermal energy from the fields of Tres Vírgenes, Ceboruco, Araró, Ixtlán de los Hervores and Los Negritos.

On the other hand, offshore probable reserves are bigger than those located onshore, and are located in the Gulf of California an area located at the East Pacific Rise. The East Pacific Rise contains the San Andrés fault in which are the Cerro Prieto and Imperial Valley geothermal fields. According to Mercado[9] the marine geothermal fields in the Gulf of California represent a potential of 97,000 MW, however, its exploration and, possible, exploitation will depend on the development of technology for the exploitation of resources in the deep sea.

Figure 2.1. Spatial distribution of the hydroelectric potential of Mexico.

Mexico has modest plans to expand the exploitation of these resources for power generation over the next few years because their investment and generation costs are higher than those obtained with the combined cycle technology.

The geothermal as the hydro projects of electric energy generation require of a long process of study to define their feasibility and to decide their construction. This process begins with an identification stage of possible exploitation sites, continues with the definition and evaluation of the project and finishes with the design of the generating power stations. Based on CFE studies, a set of geothermal projects has been identified. This set of interesting specific projects is shown in Table 2.9.

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[9] Mercado, S., Manifestaciones Hidrotermales Marinas de Alta Temperatura (350 °C) Localizadas a 21° N a 2 600 m de Profundidad en La Elevación Este del Pacífico, Geotermia, Rev. Mex. De Geoenergía, Vo. 6, No. 3, 1990, pp. 225-263.

2.2.7. Wind resources

For the estimation of the magnitude of the aeolian power resource it is required to process the inventory of Aeolian basins which includes: sites, extension in aeolian hectares, topographic characteristics, wind rose, energetic winds, dominant courses, etc. The results of this process would allow us to develop a topographic distribution shape of aeolian power generators, and to determine an index of installable capacity by hectare that multiplied by total surface would indicate the installable total capacity in the site[10].

Table 2.8. Geothermal reserves of Mexico

Reserves	MW
Onshore	
High enthalpy hydrothermal systems	11 000-13 000
Low enthalpy hydrothermal systems	48 000
Geopressurized systems	Not available
Dry hot-rock systems	Not available
Offshore	97 000

Source: Mercado, S., Posibilidades de Participación de la UNAM en el Desarrollo de la Energía Geotérmica, in Tecnologías Energéticas del Futuro, Foros de Consulta Permanente del Programa Universitario de Energía, J. Quintanilla (Ed.), Programa Universitario de Energía, UNAM, México, 1983, pp. 153-179.

Figure 2.2. Location of the main geothermal fields in Mexico.

The average speed of the wind in the site would be indicative of the possible plant factor and therefore of the expected gross generation in GW·h/year. This procedure would quantify probable reserves. To calculate proven reserves of the wind resource it will be necessary to have a detailed characterization in a feasibility study level

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[10] http://www.conae.gob.mx/renovables/eolica.html

Table 2.9. Geothermal projects with feasibility studies in process

Area	Project	Location	Number of units × unit's power	Total capacity	Annual average generation	Study level
				MW	*GW·h*	
Occidental	La Primavera	Jalisco	3 × 28	83	621	F
Oriental	Los humeros	Puebla	2 × 28	55	414	F
Total				**138**	**1 035**	

F = Feasibility in process

Source: [5]p.114.

In 1977, the Instituto de Investigaciones Eléctricas (IIE) initiated an analysis of the weather data of Mexico to determine the national aeolian potential. Currently, the knowledge of the aeolian energy resource in Mexico is at exploratory and recognition level, nevertheless, weather data measurements have served to confirm, at pre-feasibility level, the existence of winds that are technically usable and economically viable in the following regions:

- **South of Isthmus of Tehuantepec**: An area of about 1,000 km^2 in this region is exposed to very intense winds. It is due to a monzonic phenomenon between the Gulf of Mexico and the Gulf of Tehuantepec. This phenomenon produces a warm sea wind, originating a thermal and pressure gradient that give rise to an intense north wind from autumn to spring. Considering the existing electrical infrastructure and other land uses, this region could assimilate an installed power capacity of 2,000 to 3,000 MW, with an average plant factor of 0.45.
- **Peninsula of Baja California:** This peninsula is interesting in an aeolian way because of several reasons: its geographic extension, its low population density, it is electrically supplied by isolated systems, and it is a perpendicular natural barrier to the western winds. In its mountains and innumerable places can provide many sites with exploitable potential. The town of the Rumorosa and bordering zones, as well as the pass between the Sierra de Juárez and the Sierra de San Pedro Mártir are identified regions with high aeolian potential that are indicative of what can be found in many other places of this peninsula.
- **The Yucatan Peninsula:** The exposition of this peninsula to trade winds of spring and summer, increased in its eastern coast by the sea breeze, and to the northerly winds in the winter, does to Cabo Catoche, the coast of Quintana Roo and the east of Cozumel, zones with interesting aeolian potential, to contribute significantly to the electric generation requirements of the peninsula.
- **North high plateau:** The north of the country, from the central region of Zacatecas to the border with the United States, is influenced by an intense and persistent jet stream from October to March. When this west wind hit the Sierra Madre Occidental produces an innumerable sites with exploited potential. There are windy areas in the north part of the state of Coahuila.

- **Central Region**: The prevailing winds in the central region of the high plateau, from the state of Tlaxcala to the state of Guanajuato, are the summer trade winds. Those from the north high plateau and the south winds from the Tehuantepec Isthmus complement these winds, seasonally. The orography of this region has innumerable pass and plateaus where the wind could be used.

Given the extension of the Mexican territory, the anemometric measurements are very limited. Nevertheless, already the regions with greater potentiality have been identified. Figure 2.3[11] shows the regions with higher possibilities for the installation of aeolian power stations, as well as the estimation of the installable capacity in each region. The total estimated wind power capacity is 5,000 MW[12].

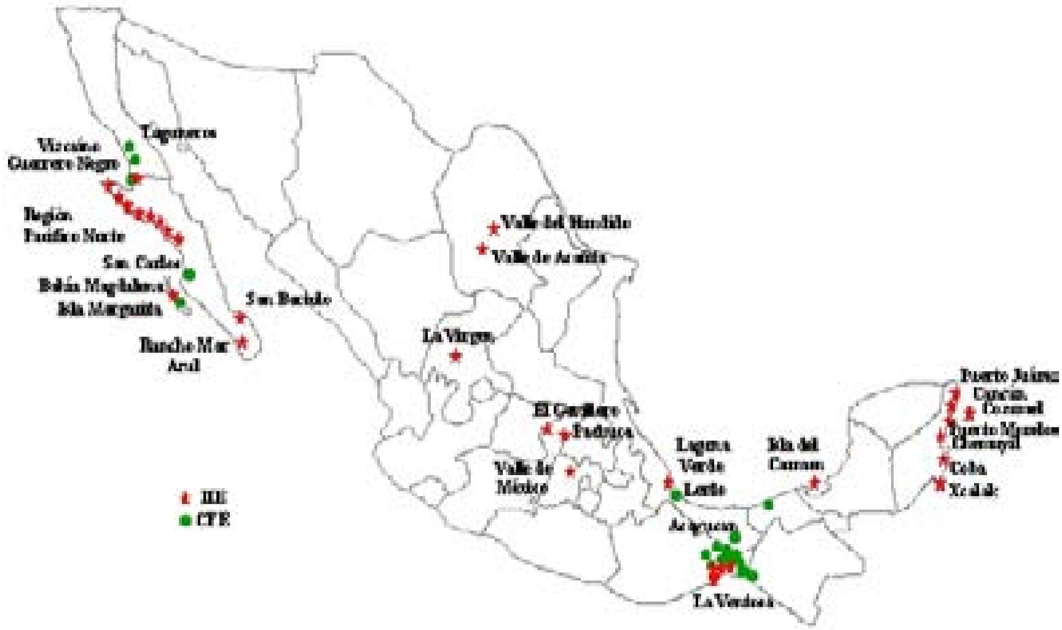

Figure 2.3. Possible locations for the installation of aeolian power stations in Mexico.

2.3. Energy supply

Mexico, as an important crude oil and natural gas producer and exporter, strongly relies on these energy sources and their derived products for the satisfaction of its energy requirements. The energy system of Mexico is strongly based on fossil fuels. There is also a significant non-commercial use of firewood that contributes to the continued deforestation of the country. Sugar cane bagasse contributes as an energy source for the sugar cane industry and as a raw material for the paper and cellulose industries. For power generation, in addition to the fossil fuels (coal, fuel oil, diesel and natural gas) contribution, there are contributions from nuclear, hydro, geothermal and wind energies for power generation.

Therefore, to satisfy its energy requirements, Mexico depends on the domestic production of these primary and secondary sources and on imports of oil products (gasoline, diesel, kerosene and fuel oil), natural gas, coal, coal coke, petroleum coke, liquefied petroleum gas (LPG), kerosene and electricity.

Table 2.10 shows the supply structure of the Mexican energy system for the last five years. The energy supply has an 87% dependence on fossil fuels, of which oil accounts for an

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[11] *Ibidem,* p. 120.

[12] Jorge M. Huacuz and Marco A. Borja, Generación Eléctrica con Energía del Viento, Bulletin IIE, March/April , México, 1998, pp. 59–63.

amount over 53%, natural gas over 30%, domestic coal over 2.3% and imports (oil products, coal, coke and natural gas) over 7%. Biomass (sugar cane bagasse and firewood) plays a significant role over 3.5%. Hydro, geothermal, nuclear and wind energies supply the remaining 4.2%.

The meaning of all the concepts in Table 2.10 is clear and straightforward, however, the maquila’s concept needs a brief description. The maquila's concept is a mechanism by which Mexico sends a given crude oil mix for processing in a refinery in the south of the United States and returns oil derivatives (LPG, gasoline, diesel and kerosene). Therefore, the figures under the maquila’s concept, shown in Table 2.9, correspond to the transformation and other losses. As an example, during the year 2001, Mexico sent 137.704 PJ of crude oil for processing under the maquila’s mechanism and return LPG (2.182 PJ), gasoline (77.601 PJ), kerosene (2.425 PJ) and diesel (20.120 PJ).

Table 2.10. Energy supply structure

	1997		1998		1999		2000		2001	
	PJ	**%**	**PJ**	**%**	**PJ**	**%**	**PJ**	**%**	**PJ**	**%**
Domestic production										
Hydrocarbons	8 383.24	85.05	8 561.90	86.87	8 355.16	84.77	8 556.53	86.81	8 700.85	88.28
Biomass (bagasse and firewood)	342.51	3.48	347.30	3.52	343.88	3.49	341.91	3.47	348.84	3.54
Hydraulic	271.15	2.75	252.96	2.57	336.15	3.41	342.07	3.47	291.82	2.96
Coal	189.71	1.92	199.41	2.02	203.85	2.07	226.70	2.30	239.07	2.43
Geothermal	56.08	0.57	58.13	0.59	57.78	0.59	61.03	0.62	57.13	0.58
Nuclear	112.50	1.14	100.47	1.02	108.26	1.10	90.33	0.92	96.67	0.98
Wind	0.04	0.00	0.05	0.00	0.06	0.00	0.08	0.00	0.07	0.00
Subtotal domestic production	***9 355.22***	***94.92***	***9 520.22***	***96.59***	***9 405.13***	***95.42***	***9 618.64***	***97.59***	***9 734.45***	***98.76***
Imports	688.83	6.99	776.43	7.88	735.43	7.46	893.34	9.06	872.37	8.85
Inventory changes	-12.34	-0.13	17.11	0.17	53.25	0.54	38.27	0.39	-91.60	-0.93
Exports	-3 876.39	-39.33	-3 942.10	-40.00	-3 731.78	-37.86	-3 857.60	-39.14	-3 932.29	-39.90
Others (spills, flaring, …)	-175.41	-1.78	-254.95	-2.59	-194.19	-1.97	-188.79	-1.92	-146.27	-1.48
Maquila					-31.71	-0.32	-61.49	-0.62	-35.38	-0.36
Total internal supply	**5 979.92**		**6 116.72**		**6 236.14**		**6 442.37**		**6 401.29**	

Source: JQM, prepared on the basis of the National Energy Balances, 1997-2001, Secretaría de Energía, México.

Imports represent an important fraction of the total energy supply and is expected that this concept will increase, substantially, in the future. During year 2001, imports account for a total of 872.370 PJ, of which, in order of importance, gasoline imports came in first place, 254.142 PJ; followed by the fuel oil imports (198.792 PJ); LPG (136.032 PJ); natural gas (133.931 PJ); coal (76.353 PJ); petroleum coke (43.468 PJ); diesel (13.579 PJ); coal coke (10.944 PJ) and kerosene (3.952 PJ).

Table 2.11. Crude oil production by region, crude oil type and distribution

Crude oil production by region and crude oil type										
	thousand barrels per day									
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Total	2 667.9	2 673.5	2 685.1	2 617.2	2 858.3	3 022.3	3 070.4	2 906.1	3 011.8	3 127.0
Heavy oil	1 350.4	1 320.7	1 270.0	1 220.4	1 370.6	1 567.1	1 658.9	1 563.5	1 774.3	1 997.0
Light oil	735.2	790.6	890.0	864.1	910.0	881.5	848.4	806.2	733.1	658.7
lighter oil	582.3	562.2	525.1	532.7	577.7	573.7	563.1	536.4	504.6	471.4
Northeastern marine region	1 296.1	1 300.9	1 287.9	1 215.8	1 352.6	1 540.2	1 641.5	1 554.3	1 763.2	1 985.8
Heavy oil	1 295.7	1 264.9	1 214.8	1 165.5	1 314.6	1 511.0	1 605.4	1 516.3	1 730.5	1 953.7
Light oil	0.4	36.0	73.1	50.3	38.0	29.2	36.1	38.0	32.7	32.1
Southern marine region	618.1	649.0	713.8	721.6	779.5	758.9	715.7	683.5	621.7	554.0
Light oil	618.1	649.0	713.8	721.6	779.5	758.9	715.7	683.5	621.7	554.0
Southern region	654.6	625.3	585.7	584.5	629.9	626.9	620.8	587.2	549.5	508.7
Heavy oil	1.5	1.4	1.1	1.0	1.0	0.6	0.2			
Light oil	70.8	61.7	59.5	50.8	51.2	52.6	57.5	50.8	44.9	37.3
lighter oil	582.3	562.2	525.1	532.7	577.7	573.7	563.1	536.4	504.6	471.4
Northern region	99.1	98.3	97.7	95.3	96.3	96.3	92.4	81.1	77.4	78.5
Heavy oil	53.2	54.4	54.1	53.9	55.0	55.5	53.3	47.2	43.7	43.3
Light oil	45.9	43.9	43.6	41.4	41.3	40.8	39.1	33.9	33.7	35.2

Crude oil distribution										
	thousand barrels per day									
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Distribution	2 665.0	2 649.8	2 673.0	2 590.9	2 828.7	2 997.3	3 055.9	2 889.9	2 986.4	3 105.6
Refineries	1 061.0	1 100.1	1 152.2	1 073.9	1 068.9	1 072.6	1 154.5	1 132.5	1 126.9	1 140.4
Maquila								56.7	103.7	62.3
Petrochemical plants	219.0	205.0	206.1	206.1	207.4	194.3	163.4	149.6	136.0	146.2
Exports	1 385.0	1 344.7	1 314.7	1 310.9	1 552.3	1 730.5	1 738.0	1 551.2	1 619.8	1 756.6
Stock changes, statistical differences	2.7	23.6	12.1	26.3	29.7	24.9	14.6	16.1	25.6	21.4

Source: JQM, prepared on the basis of *PEMEX Statistical Yearbook, 1999–2002*

Clearly, the imports structure by fuel type will depend on the expected demand by fuel type, the refining and gas processing capacities in the country and on how much crude oil could be processed through the maquila's mechanism. In the future, the effectiveness of this mechanism will depend on the demand growth for oil derivatives in the United States, especially on the future demand of gasoline and diesel, and the available capacity for crude oil refining in the United States[13] since the prevailing regulatory and environmental conditions, among others, have deterred investments in new refining capacity.

2.3.1. Crude oil production

At present, most of the oil production that is associated with natural gas comes from the marine oil fields, located in the Gulf of Mexico. Mexican crude oil is extracted from onshore and offshore. Offshore crude oil production accounts for the main portion of the total oil production. In order to satisfy the domestic demand and maintain the exports platform PEMEX-Exploration and Production has reached a level of production over 3 million barrels of crude oil per day (Table 2.11) and operates more than 300 producing fields with a total of 4,200 producing wells and 185 offshore platforms. Additionally, it operates 11,258 km of pipelines to collect the crude oil and gas from the producing wells and its transportation into the exporting facilities, refineries, and gas and fractionating plants.

Crude oil is distributed according to the share shown in Table 2.11, over 50% (56.2% in 2001) of the total domestic production is exported into more than 20 countries; the remaining amount is transported by pipeline into the 6 refining facilities and to La Cangrejera petrochemical facility, where, after the extraction of naphthas and some light hydrocarbons for the production of aromatics, is sent back, by pipeline, into the refining facilities.

In Mexico, there are 6 refineries - Salamanca and Tula, located at the central area of the country, Cadereyta and Madero in the northeast, Minatitlán in the south part of the Gulf of Mexico and Salina Cruz in the south pacific part of the country. At present, atmospheric distillation capacity accounts for 1.56 million barrels of crude oil per day. Atmospheric distillation accounts for the highest capacity followed by vacuum distillation, reforming, catalytic and thermal cracking, hydrodesulphurization, visbreaking and natural gas liquids fractionating (Table 2.12).

The crude oil and liquids processed in the Mexican refining system is shown in Figure 2.4. The amount of crude oil and liquids processed shows an increasing pattern during 1991 up to 1994 except for the reduction of 105,000 barrels of crude oil per day due to the decision of closing, for environmental reasons, in 1992, the Azcapotzalco's refinery, located in Mexico City. During the years 1995 up to 1997 shows the effect of the economic crisis that started in December 1994, an increase in 1998, a decrease in 1999 and 2000 and an increase in 2001.

This decrease is due, mainly, to the PEMEX Reconfiguration Program, specifically due to the reconfiguration of the Cadereyta's refinery. The main purpose of the Reconfiguration Program aims to be in position to satisfy the expected changes in the composition of the demand of oil products. The aim is to modify the production structure going into products with a higher added value, satisfy the expected growth in the demand and to be able of

[13] According to the document National Energy Policy (Report of the National Energy Policy Development Group), published by the White House in May 2001, the U.S. refining industry has experienced a decade of low profitability and rates of return on investment. This has discouraged investment in new refineries. In fact, almost 50 U.S. refineries closed over the last ten years, and no major refineries have been built in the last twenty-five years.

processing a greater volume of heavy oil in the National Refinery System (NRS). The Reconfiguration Program covers the 6 refineries and consists in the construction of 41 new plants and the upgrading and modernization of 20 more.

Table 2.12. Crude oil refining capacity

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
	thousand barrels daily									
Atmospheric distillation	1 524.0	1 520.0	1 520.0	1 520.0	1 520.0	1 525.0	1 525.0	1 525.0	1 559.0	1 559.0
Vacuum distillation	712.7	760.7	760.7	760.7	761.7	761.7	757.1	757.1	774.8	773.8
Catalytic and thermal cracking	271.5	331.5	372.0	372.0	377.0	368.0	368.0	368.0	375.0	375.0
Visbreaking	49.0	91.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0	141.0
Reforming	136.8	166.8	222.8	222.8	227.8	227.8	226.0	226.0	268.8	268.8
Hydrodesulphurization	562.0	648.0	648.0	648.0	698.0	698.0	748.0	748.0	808.0	848.0
Natural gas liquids fractionation	71.0	71.0	71.0	71.0	71.0	71.0				

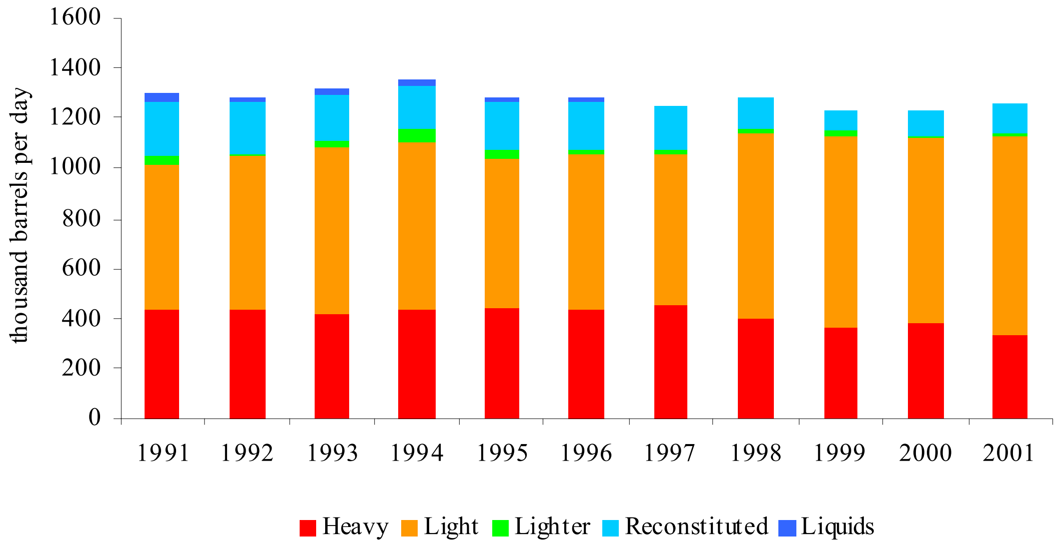

Figure 2.4. Crude oil and liquids processed in the National Refining System.

The composition of crude oil feed stock and the chosen slate of petroleum products largely determine a refinery's processing flow scheme. Figure 2.4 also presents the composition of crude oil feed stock for the NRS. It becomes clear the systematic reduction of the heavy crude oil processed in the NRS and the increasing participation of the light crude oil. Lighter crude oil has a marginal participation in the input of crude oil to the NRS. The refineries of Madero, Minatitlán, Salamanca and Tula show this trend. The exceptions to this trend for the crude oil input to the refineries are the Salina Cruz refinery and the reconfiguration program of the Cadereyta's refinery.

Table 2.13 shows the main oil products for each one of the refineries. Fuel oil production shows a more or less steady pattern with a clear reduction in the Cadereyta's refinery, a decreasing pattern in Madero and Salamanca refineries, an increasing one in Tula and Salina Cruz refineries and a steady level of fuel oil production in Minatitlán's refinery. Diesel shows a similar behavior as fuel oil for each one of the refineries. On the other hand, gasoline shows an increasing pattern, however gasoline consumption has to be complemented with important amounts of imports and crude oil processing through the maquila mechanism. Low sulfur fuel oil and diesel are imported due, mainly, to environmental and logistic considerations.

Table 2.13. Oil products by refining center

Oil products by refining center *thousand barrels daily*									
	1993	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**
Cadereyta									
Gasoline	55	54	50	46	48	50	41	34	64
Diesel	36	42	39	39	44	47	28	31	59
Fuel oil	68	65	64	55	61	60	38	50	66
LPG	6	6	6	6	6	5	2	1	2
Kerosene	15	15	10	5	5	1	1	0	3
Others	5	7	8	8	9	9	4	4	10
Madero									
Gasoline	49	50	43	39	41	41	43	40	23
Diesel	38	38	34	30	30	30	37	35	26
Fuel oil	51	44	45	50	51	46	41	40	32
LPG	4	5	6	6	6	3	4	2	0
Kerosene	5	5	5	3	3	4	3	3	1
Others	32	34	35	18	20	24	26	20	8
Minatitlán									
Gasoline	74	76	79	63	53	64	60	55	56
Diesel	43	44	37	38	37	36	40	38	37
Fuel oil	66	68	63	62	65	67	64	67	70
LPG	20	19	11	16	3	4	7	5	7
Kerosene	15	14	10	8	9	8	6	4	4
Others	7	9	9	11	7	7	8	8	8
Salamanca									
Gasoline	70	69	62	61	63	56	59	55	55
Diesel	43	46	35	40	43	42	39	41	38
Fuel oil	45	39	46	43	54	54	49	54	55
LPG	8	7	8	6	4	2	1	3	3
Kerosene	10	8	9	10	10	12	12	12	12
Others	31	33	26	23	21	19	23	25	24
Salina Cruz									
Gasoline	96	100	99	100	95	106	102	102	89
Diesel	60	61	57	62	60	72	65	60	64
Fuel oil	107	105	110	110	98	118	134	117	115
LPG	10	14	16	13	10	4	5	6	6
Kerosene	18	17	21	20	13	12	14	16	15
Others	22	13	13	13	13	15	12	16	14
Tula									
Gasoline	72	82	88	107	89	95	102	106	102
Diesel	47	53	53	64	61	62	62	60	59
Fuel oil	82	98	89	99	96	100	99	92	92
LPG	11	14	15	15	10	10	11	8	10
Kerosene	21	26	22	22	18	22	22	21	22
Others	11	14	11	14	19	21	16	11	10
Total									
Gasoline	416	431	421	416	389	412	407	392	389
Diesel	267	284	255	273	275	289	271	265	283
Fuel oil	419	419	417	419	425	445	425	420	430
LPG	59	65	62	62	39	28	30	25	28
Kerosene	84	85	77	68	58	59	58	56	57
Others	108	110	102	87	89	95	89	84	74

Source: JQM, prepared on the basis of *PEMEX Statistical Yearbook, 1999-2002*

2.3.2. *Natural gas production*

Similar to the crude oil production, currently most of the natural gas production comes from the marine oil fields, located in the Gulf of Mexico. A big portion of the present production of natural gas is associated to oil. Mexican natural gas is extracted from onshore and offshore gas fields. Onshore natural gas production dominates. Associated natural gas contributes with the main portion to the total natural gas production of the country (Table 2.14).

Table 2.14. Associated and non-associated natural gas production

Natural gas production										
Associated gas (million cubic feet per day)										
Region	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**
Northeastern Marine Region	562.73	573.61	562.57	546.94	581.88	639.78	685.92	648.21	737.17	794.17
Southwestern Marine Region	611.21	670.76	776.02	831.66	980.76	1 008.65	999.94	921.55	819.74	735.57
Southern Region	1 726.66	1 723.37	1 640.76	1 649.14	1 788.05	1 853.83	1 887.77	1 838.56	1 709.13	1 596.73
Northern Region	55.73	61.19	62.46	62.87	104.63	128.30	130.18	117.50	114.57	112.72
Total	2 956.33	3 028.92	3 041.82	3 090.62	3 455.31	3 630.55	3 703.83	3 525.81	3 380.61	3 239.19
Non-associated gas (million cubic feet per day)										
Region	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**
Southern Region	219.07	167.35	166.12	183.08	201.64	191.73	179.47	157.75	147.75	146.49
Northern Region	339.23	316.13	351.00	422.28	515.13	644.85	907.90	1 107.12	1 151.41	1 125.21
Total	558.30	483.48	517.12	605.35	716.76	836.58	1 087.37	1 264.87	1 299.16	1 271.70
Total	3 514.63	3 512.41	3 558.94	3 695.98	4 172.08	4 467.13	4 791.20	4 790.68	4 679.77	4 510.89

Source: JQM, prepared on the basis of *PEMEX Statistical Yearbook, 1999-2002 and PEMEX: Memoria de Labores, 1999-2001*

Associated natural gas is extracted from both regions, marine and main land. Burgos region, located at the northeast part of the country, is becoming an important natural gas production zone, however, its importance will depend on the amount of proved reserves and the available infrastructure (at present and in the future) for production and transportation.

During the period 1992–2001, the delivery of natural gas from PEMEX-Exploración y Producción to PEMEX-Gas y Petroquímica Básica has presented continuous increase with an annual growth rate of 3.1%. The greatest growth has been in the dry gas that it comes directly from the fields (Table 2.15), its volume contribution has increased 5.5 times its value in 1992, passing from the 3.88% in 1992 to 16.36% in 2001.

Table 2.15. Natural gas processing

million cubic feet daily	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Wet sour gas	2 745	2 788	2 837	2 849	3 034	3 088	3 177	3 071	3 166	3 179
Wet sweet gas	430	344	352	281	192	250	391	456	471	450
Dry gas direct from fields	128	134	149	190	277	381	599	750	752	710
Total	**3 303**	**3 266**	**3 338**	**3 320**	**3 503**	**3 719**	**4 167**	**4 277**	**4 389**	**4 339**

Source: JQM, prepared on the basis of *PEMEX Statistical Yearbook, 1999-2002 and PEMEX: Memoria de Labores, 1999-2001*

Table 2.16. Natural gas processing capacity

million cubic feet daily	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Sweetening plants										
Sour condensates (a, e)	120.0	120.0	120.0	120.0	168.0	192.0	192.0	192.0	192.0	144.0
Sour natural gas (e)	3 760.0	3 753.0	3 753.0	3 553.0	3 553.0	3 553.0	3 753.0	3 753.0	3 753.0	3 923.0
NGL recovery plants	**4 629.0**	**4 204.0**	**4 204.0**	**4 204.0**	**3 384.0**	**3 984.0**	**4 709.0**	**5 034.0**	**5 034.0**	**5 034.0**
Cryogenics (b)	3 329.0	3 454.0	3 454.0	3 454.0	2 634.0	3 234.0	3 959.0	4 559.0	4 559.0	4 559.0
Absorption	1 300.0	750.0	750.0	750.0	750.0	750.0	750.0	475.0	475.0	475.0
NGL fractionating (a, c)	450.0	450.0	450.0	450.0	450.0	450.0	554.0	554.0	554.0	554.0

(a) Thousand barrels daily

(b) Includes the cryogenic plant located in La Cangrejera

(c) Includes liquid recovery plants

(d) Up to 1992 includes two shutdown processing unit with 275 million cubic feet daily of available capacity each

(e) In 2001, two sour condensates sweetening plants were habilitated for sour natural gas processing

Source: JQM, prepared on the basis of *PEMEX Statistical Yearbook, 1999-2002 and PEMEX: Memoria de Labores, 1999-2001*

On the other hand, the wet sour gas participation went from 83.11% in 1992 to 73.27% in 2001. The wet sweet gas contribution was 13.02% in 1992 and 10.37% in 2001. As we can see, most of the input gas is sour gas and therefore the necessity of a large amount of sweetening capacity. Also, a very big portion of the processed gas is wet gas and a small portion of reprocessing streams. This implies a large capacity of natural gas liquids recovery plants. On the other hand, Mexico's natural gas has a high content of sulfur, implying, also, a large capacity of sulfur recovery. As far as 2001, the Mexican gas processing system includes 19 sweetening, 14 cryogenic, 8 condensates sweetening, 15 sulfur recuperation 7 fractionating and 3 absorption plants. The total capacity by type of plant is shown in Table 2.16, and is distributed between 10 processing centers, 9 of them located in the southeast part of the Gulf of Mexico and the remaining one in the Northeast part of the country. The transportation infrastructure for natural gas consists of 9,511 km of gas pipelines and 3,147 km of pipelines for natural gas products.

Finally, Table 2.17 shows the production of natural gas, liquefied petroleum gas, gasoline, kerosene, diesel, fuel oil and sulfur in the Mexican gas processing system. As we can see dry natural gas becomes the most important product in terms of volume, however liquefied petroleum gas is of central importance for the residential sector, which constitutes the largest LPG consumer worldwide.

Table 2.17. Natural gas and products from the gas and fractionating plants

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
GLP (thousand bbl/day)	202.564	207.999	200.982	194.994	186.584	176.742	195.949	201.211	203.637	205.545
Gasoline (thousand bbl/day)	69.486	77.007	69.937	72.552	78.928	84.342	87.639	83.964	84.637	88.334
Kerosene (thousand bbl/day)								0.413	0.894	1.196
Diesel (thousand bbl/day)								0.447	0.033	0.000
Fuel oil (thousand bbl/day)								0.192	0.315	0.471
Non energy products										
Natural gas (million cf/day)	2 314.844	2 514.002	2 570.006	2 477.005	2 691.014	2 825.101	2 835.801	2 723.201	2 804.299	2 818.399
Sulfur (ton/day)	1 765.027	1 819.178	1 928.767	1 969.863	2 079.235	2 054.795	2 024.658	1 882.192	1 806.011	1 873.973

Source: JQM, prepared on the basis of *PEMEX Statistical Yearbook, 1999-2002 and PEMEX: Memoria de Labores, 1999–2001*

As in the case of the oil and gas derivatives (gasoline, diesel, fuel oil, petrochemicals and others) the country requires some imports of LPG, natural gas, propane and other oil and gas products in order to satisfy the internal demand and fulfill the exporting compromises to several countries worldwide. As we mentioned in the oil section, imports of gasoline, diesel and fuel oil are increasing fast, especially gasoline and, to some extent fuel oil. LPG imports are growing fast; they quadruplicate in the last 10 years and natural will growth fast as a consequence of the expected penetration of natural gas in the power, industrial, transport and residential sectors.

2.3.3. Coal production

The historical production of coal is shown in Table 2.18. The figures reported in the table for the domestic production of both types of coal correspond to the coal production before the washing process. National Energy Balances spreadsheets report, both types of coal after the washing process.

After de extraction of thermal and metallurgical coal, the amount produced of each of these types of coal, suffers an increment/reduction due to inventory variations, self-consumption, transportation losses and statistical differences. The resulting amount of metallurgical coal goes, directly to the washing process. After this process and an increment/reduction due to inventory variations and statistical differences, the remaining amount plus the imports minus the exports goes to the coking process and, from there, to the iron and steel, cement, mining and glass industries.

On the other hand, for the thermal coal there are two streams, one that it requires to be washed and, as a consequence, some losses due to this transformation process and the other that it does not require of this processing. The two streams are added and, after an increment/reduction due to inventory variations and statistical differences the remaining amount plus the imports are sent to the coal power utilities for electricity generation.

It is considered that any future expansion of the use of coal for thermal purposes will have to relay on imported coal, since national reserves are, just enough, to satisfy the demand from the existing coal power plants.

Table 2.18. Domestic productions, imports, exports and processing of thermal and metallurgical coal

Coal type	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Metallurgical (thousand ton)										
Domestic production	3 448.735	4 744.809	4 603.422	4 248.835	4 493.931	4 050.813	4 243.927	4 718.084	6 348.580	6 163.757
To washing process	3 268.528	3 483.583	4 788.833	3 745.829	3 926.751	4 061.432	4 358.215	4 668.697	4 689.989	4 474.751
Imports	634.029	82.734	290.733	819.810	938.230	1 178.422	1 209.918	1 381.656	1 800.339	1 177.175
Exports	0.013	4.972	0.599	0.485	14.894	0.323	1.906	69.369	3.956	7.659
To coking process	2 487.566	2 439.363	2 493.380	2 694.953	2 752.509	2 684.489	2 689.179	2 719.670	2 728.825	2 521.867
Thermal (thousand ton)										
Domestic production	5 251.192	5 470.543	6 828.800	7 196.920	7 935.562	8 167.299	7 280.540	8 584.261	7 938.558	6 013.126
To washing process	2 175.146	1 836.284	279.012	2 464.387	2 381.121	3 109.455	2 550.934	2 808.158	3 374.713	2 997.760
Not require washing process	2 960.804	3 371.106	6 570.128	5 278.715	5 981.130	4 835.010	5 972.236	5 843.340	6 053.017	7 046.489
Imports				451.160	638.501	1 018.683	1 157.110	1 132.503	635.637	2 263.441
To power utilities	4 248.961	5 393.005	6 696.200	7 549.677	8 984.218	8 852.700	9 345.265	9 468.498	9 566.001	11 398.000

Source: JQM, prepared on the basis of the Balances Nacionales de Energía, Secretaría de Energía, México.

2.3.4. Uranium production

Production of uranium in Mexico does not exist, except for a molybdenum small industrial pilot plant in Villa Aldama in the state of Chihuahua. This pilot plant obtained, as a sub-product, an equivalent of 47 tons of U_3O_8. The plant was in operation from 1969 up to 1971 and operations were suspended due to the exhaustion of the mineral. The uranium used in the nuclear power plant of Laguna Verde is imported and there are no exports at all.

2.3.5. Hydro-electric capacity and energy production

According to information published by CFE[14], in 1999 and 2000, the hydroelectric potential exploited for electricity generation was 9,618.2 and 9,619.2 MW, respectively. These capacities represent the 26.97 and 26.56 percent of the total generation capacity for those

[14] Informes de Operación, 1999–2000, CFE, México, 1999 y 2000.

years. In both years, the number of hydroelectric power stations in operation was 71 and a net annual generation of 32,275 and 32,623.4 GW·h, respectively. These generations represent the 18.82 and 17.28 percent of the total net generation of the country and give an idea of the importance of these energy resources.

2.3.6. Geothermal capacity and energy production

In year 2000, there were three geothermal fields in exploitation, Cerro Prieto (Baja California) with an installed capacity of 720 MW and a net generation of 4,852.7 GW·h; Los Azufres (Michoacán) with 92 MW and a net generation of 572.95 GW·h; Los Humeros (Puebla) with 42 MW and a net generation of 202.94 GW·h.

2.3.7. Wind capacity and energy production

For the same reasons as in the case of the geothermal resource, Mexico has modest plans for the expansion of the use of wind for power generation in the next few years. The country currently has only 3.1 megawatts of wind-driven capacity. In Mexico, at the end of 1998, there were four wind projects in operation, with several small units serving niche groups (Figure 2.5[15]).

In 1994, near to La Venta, Oaxaca, the first aeolian power station in Mexico was installed, with a capacity of 1,575 kW, composed of seven aeolian generating units of 225 kW. These generating units are shown in Figure 1.6[16]. In Guerrero Negro (1), it is installed one 600-kilowatt Gamesa eolic turbine, operated by CFE. Also, in Guerrero Negro (2), there is a 250-kilowatt Mitsubishi turbine, operated by Exportadora de Sal. In La Venta I (3), there are seven 225-kilowatt Vestas turbines, operated by CFE and, in Ramos Arizpe (4), one 550-kilowatt Zond turbine, operated by Cementos Apasco.

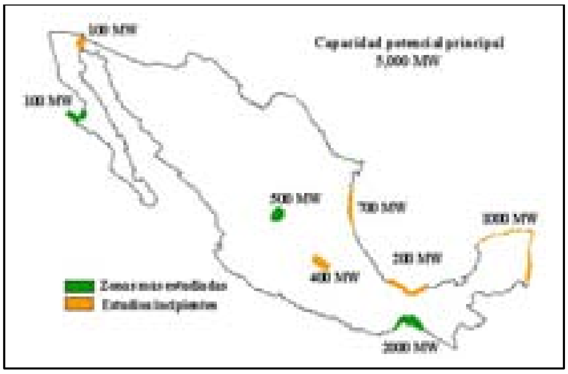

Figure 2.5 National potential of aeolian capacity

Figure 2.6 Wind turbine installations in Mexico

Finally, Table 2.19 shows the only wind project that is considered in the catalog of renewable energy utilities. Its location will be at La Venta existing wind utility and will expand the installed capacity by 54 MW through two units of 27 MW each.

It is estimated that by the middle of present century, Mexico's population will stabilize around 131 million inhabitants and the electrical system will have an installed capacity of 125,000 MW. Under these conditions, the aeolian energy and other renewable energies will be able to contribute with several thousands MW to the installed capacity.

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[15] National Renewable Energy Laboratory and International Energy Agency, IEA Wind Energy Annual Report 1998 (Golden, CO, April 1999), p. 109.

[16] http://axp16.iie.org.mx/FnoC/eolica22/fotos_inf_graf/fotografia4.1.htm

Table 2.19. Wind projects with feasibility studies in process

Area	Project	Location	Number of units × unit's power	Total capacity	Annual average generation	Study level
				MW	*GW·h*	
Oriental	La Venta	Oaxaca	2 × 27	54	237	F
Total				**54**	**237**	

F = Feasibility in process

Source: [5] P:114

Table 2.20. Total energy and feedstock consumption

	1997		1998		1999		2000		2001	
	PJ	% end use	PJ	% end use	PJ	% end use	PJ	% end use	PJ	% end use
Transformation										
Oil sector	782.00	13.08	753.95	12.61	854.36	14.29	895.65	14.98	1 001.61	16.75
Electric sector	1 191.99	19.93	1 268.24	21.21	1 338.88	22.39	1 430.76	23.93	1 442.54	24.12
Coking sector	13.52	0.23	12.65	0.21	13.62	0.23	32.73	0.55	15.79	0.26
Subtotal transformation	***1 987.51***	***33.24***	***2 034.83***	***34.03***	***2 206.86***	***36.90***	***2 359.14***	***39.45***	***2 459.94***	***41.14***
End use energy										
Industrial	1 288.47	21.55	1 320.65	22.08	1 242.10	20.77	1 274.03	21.31	1 166.37	19.50
Transport	1 478.14	24.72	1 527.26	25.54	1 548.04	25.89	1 614.33	27.00	1 600.31	26.76
Residential	697.86	11.67	717.98	12.01	685.66	11.47	705.50	11.80	708.12	11.84
Commercial	124.55	2.08	132.25	2.21	99.79	1.67	108.99	1.82	112.13	1.88
Public	18.35	0.31	18.64	0.31	19.56	0.33	21.14	0.35	21.50	0.36
Agricultural	106.92	1.79	106.56	1.78	116.88	1.95	115.52	1.93	110.39	1.85
End use subtotal	***3 714.28***	***62.11***	***3 823.34***	***63.94***	***3 712.02***	***62.07***	***3 839.51***	***64.21***	***3 718.83***	***62.19***
End use feedstock	278.13	4.65	258.54	4.32	317.26	5.31	243.72	4.08	222.47	3.72
Total consumption	**5 979.92**		**6 116.72**		**6 236.14**		**6 442.37**		**6 401.24**	
Total consumption growth rate	3.48		2.29		1.95		3.31		-0.64	

Source: JQM, prepared on the basis of the National Energy Balances, 1997-2001, Secretaría de Energía, México.

2.4. Energy consumption

Table 2.20 shows the energy consumption of the energy transformation sectors (oil and gas, power and coking) and the end use sectors. The middle part of the table shows the split of the end use energy consumption into industrial, transport, residential, commercial, public and agricultural sectors. In addition, the lower part of the table shows, in energy terms, what is used as raw material in the PEMEX petrochemical industry and other industrial branches.

Finally, the last row of the table shows the growth rate of the energy consumption of a given year with respect to the previous one.

Table 2.21. Splitting of the "energy consumption" in refineries, gas and fractionating plants

	1997 PJ	1998 PJ	1999 PJ	2000 PJ	2001 PJ
Refineries	**-284.511**	**-298.116**	**-324.643**	**-384.836**	**-433.856**
Transformation losses	**-55.942**	**-40.283**	**-17.594**	**-132.952**	**-186.989**
Self consumption	**-178.617**	**-223.740**	**-194.399**	**-184.119**	**-164.792**
Crude oil	0.000	0.000	0.000	0.000	0.000
Condensates	0.000	0.000	0.000	0.000	0.000
Petroleum coke	0.000	0.000	0.000	0.000	0.000
LPG	-3.203	-2.090	-1.298	-1.052	-1.244
Gasoline	-6.171	-39.112	-39.829	-31.073	-16.688
Kerosene	-10.019	-11.202	-0.046	-0.037	-0.002
Diesel	-40.352	-49.094	-23.182	-22.553	-24.677
Fuel oil	-85.866	-85.843	-99.577	-91.933	-83.809
Non energy products	-2.733	-2.598	0.000	0.000	0.000
Natural gas	-30.273	-33.801	-30.468	-37.470	-38.372
Statistical difference	**-12.117**	**2.216**	**-79.533**	**-35.674**	**-51.473**
Crude oil	-13.257	0.466	-28.792	-21.546	-36.465
Condensates	0.000	0.000	0.002	0.023	-0.005
Petroleum coke	0.000	0.000	0.000	0.466	-0.363
LPG	0.000	0.000	-0.595	-0.194	0.136
Gasoline	0.000	0.000	-11.849	1.406	0.424
Kerosene	0.000	0.000	-4.724	-1.605	-2.194
Diesel	0.000	0.000	-32.470	-6.007	-1.365
Fuel oil	0.000	0.000	-26.261	-0.571	-5.518
Non energy products	0.000	0.000	25.034	-7.588	-6.083
Natural gas	1.140	1.750	0.123	-0.058	-0.040
Losses (transportation, distribution & storage)	**-37.835**	**-36.31**	**-33.116**	**-32.091**	**-30.602**
Crude oil	-37.835	-36.31	-33.116	-32.091	-30.602
Gas and fractionating plants	**-497.495**	**-455.829**	**-529.720**	**-510.818**	**-567.731**
Transformation losses	**-37.277**	**-0.698**	**-78.822**	**-96.403**	**-102.610**
Self consumption	**-519.884**	**-584.190**	**-528.841**	**-592.055**	**-648.225**
Condensates	0.000	0.000	0.000	0.000	0.000
Non associated gas	-9.177	-8.311	-10.213	-12.731	-13.477
Associated gas	-54.085	-60.076	-63.210	-61.440	-66.501
Petroleum coke	0.000	0.000	0.000	0.000	0.000
LPG	-14.768	-14.235	-7.874	-8.602	-9.197
Gasoline	-1.340	-8.321	-8.240	-6.692	-3.777
Kerosene	0.000	0.000	0.000	-0.001	0.000
Diesel	0.000	0.000	-0.038	-0.003	0.000
Fuel oil	0.000	0.000	-0.040	-0.066	-0.090
Non energy products	-3.496	-2.453	0.000	0.000	0.000
Natural gas	-437.018	-490.794	-439.225	-502.521	-555.183
Statistical difference	**59.666**	**129.060**	**77.942**	**177.640**	**183.104**
Condensates	-0.015	0.000	0.045	0.438	-0.123
Non associated gas	2.155	0.234	0.747	-0.075	-2.508
Associated gas	41.071	103.413	61.228	186.031	190.600
Petroleum coke	0.000	0.000	0.000	0.000	0.000
LPG	0.000	0.000	-3.609	-1.585	1.003
Gasoline	0.000	0.000	-2.452	0.303	0.096
Kerosene	0.000	0.000	-0.033	-0.026	-0.046
Diesel	0.000	0.000	-0.053	-0.001	0.000
Fuel oil	0.000	0.000	-0.011	0.000	-0.006
Non energy products	0.000	0.000	20.307	-6.661	-5.331
Natural gas	16.455	25.413	1.772	-0.784	-0.581

Source: JQM, estimated on the basis of the National Energy Balances, 1997-2001, Secretaría de Energía, México.

2.4.1. Oil sector (refineries, gas, fractionating plants) energy consumption

The "energy consumption" of the oil sector includes the contributions from the refineries and gas and fractionating plants. The elements that participate in these contributions are: transformation losses, self-consumption, and statistical differences, as well as, the losses associated with the transportation, distribution and storage of energy. Table 2.21 shows an estimation of these elements and the splitting of them in terms of the energy sources that contribute to the participation of each element

In the case of the refineries, it is important to notice that the transformation losses shown a systematic decreasing pattern for the years from 1997 to 1999, which could be considered as an improvement pattern of efficiency in the refining system, however, for the years 2000 and 2001 we see a very important increase in the transformation losses, which could be seen as an important loss in efficiency.

A similar situation is observed in the case of the gas and fractionating plants, except for the fact that the adverse situation in the efficiency starts in 1999, a year before in comparison with the case of the refineries. With respect to the statistical differences the figures show important fluctuations in both cases, refineries and gas and fractionating plants, and call for a real improvement in the data handling and, perhaps, in the measuring process. On the other hand, in the case of the element of self-consumption, the table also shows important fluctuations in both cases, and call for attention to its trend. Finally, transportation, distribution and storage losses show a more or less steady pattern along the years considered.

2.4.2. Power sector capacity, generation and consumption

The Mexican Public Power System through the use of power plants based on technologies such as: steam, combined cycle, turbo gas, internal combustion, geothermal, dual, coal, nuclear, hydro and wind turbines converts fossil fuels (coal, fuel oil, diesel and natural gas), nuclear fuels, hydro resources and renewable energies (geothermal and wind) into electric energy.

2.4.3. Power sector capacity

By the end of 2000 total capacity (Table 2.22) was 36,696.67 MW, the public power system capacity was 35,212.67 MW and 484 MW of the Mérida III combined cycle plant operated by a PIE. The structure of this capacity was: hydro (26.21%), thermal capacity (73.78%) and wind (very small). Thermal capacity structure was steam (52.75%), combined cycle (12.55%), turbo gas (8.72%), internal combustion (0.43%), geothermal (3.16%), dual[17] (7.76%), coal (9.6%) and nuclear (5.04%).

At the end of July 2001, private producers capacity in operation was 4,484.3 MW. According to the information provided by the Comisión Reguladora de Energía (CRE), up to July 2001, the entitled permits to private producers represent a total of 15,779 MW, with a structure of: independent producers (7,619.3 MW), cogeneration (2,129.9 MW), self-supply (4,759.9 MW), importing (134.2 MW), exportation (556.2 MW) and others (579.4 MW). The structure by type of technology was: combined cycle (10,125.2 MW), steam turbines (2,604.4 MW), gas turbines (1,637.5 MW), fluidized bed (708 MW), hydraulic turbines (183.3 MW), internal combustion (260.4 MW), wind (121 MW) and others (5.22 MW).

2.4.4. Power sector generation

For the same year, in terms of gross generation (Table 2.23), fossil fuels account for the 75.34%, nuclear (4.29%), hydro (17.28%), geothermal (3.08%) and wind (less than 1%). The National Electric System (NES) generation was 191,424.06 GW·h and 837 GW·h from the PIE, therefore total generation was 192.26 TW·h. Subtraction of the own uses for electricity

[17] Dual power plants can use fuel oil or coal as fuel.

generation from the gross generation give us the net generation (Table 2.24). The net generation plus the imports minus the exports result in the net electric energy delivered to the country. Finally, the electric energy that reaches the end users is the result of the net electrical energy delivered to the country minus the transmission and distribution losses plus/minus the statistical difference.

Table 2.22. Installed electric capacity

	1997		1998		1999		2000		2001	
	MW	%	MW	%	MW	%	MW	%	MW	%
Hydro	**10 034.00**	**28.82**	**97 00.00**	**27.51**	**9 618.15**	**26.97**	**9 619.15**	**26.21**	**9 619.15**	**24.97**
Thermal	**24 779.00**	**71.17**	**25 554.00**	**72.48**	**26 045.26**	**73.03**	**27 075.34**	**73.78**	**28 897.45**	**75.02**
Steam	14 282.00	57.64	14 283.00	55.89	14 282.50	54.84	14 282.50	52.75	14 282.50	49.42
Combined cycle	1 942.00	7.84	2 463.00	9.64	2 463.42	9.46	3 397.62	12.55	5 188.35	17.95
Turbo gas	1 675.00	6.76	1 929.00	7.55	2 363.78	9.08	2 359.78	8.72	2 380.68	8.24
Internal combustion	121.00	0.49	120.00	0.47	117.66	0.45	115.66	0.43	143.14	0.50
Geothermal	750.00	3.03	750.00	2.93	749.90	2.88	854.90	3.16	837.90	2.90
Dual	2 100.00	8.47	2 100.00	8.22	2 100.00	8.06	2 100.00	7.76	2 100.00	7.27
Coal	2 600.00	10.49	2 600.00	10.17	2 600.00	9.98	2 600.00	9.60	2 600.00	9.00
Nuclear	1 309.00	5.28	1 309.00	5.12	1 368.00	5.25	1 364.88	5.04	1 364.88	4.72
Wind	**2.00**	**0.01**	**2.00**	**0.01**	**2.18**	**0.01**	**2.18**	**0.01**	**2.18**	**0.01**
Total	**34 815.00**		**35 256.00**		**35 665.59**		**36 696.67**		**38 518.78**	

Source: JQM: prepared on the basis of the Informe de Operación, 1997-2001, Comisión Federal de Electricidad, México

It is estimated that private producers contributed with an amount of 16,412 GW·h during 2001. Private producers fuel mix was: natural gas (4.523 billion cubic meter), diesel (0.326 million cubic meter), fuel oil (1.903 million cubic meter), sugar cane bagasse (4.805 million ton), blast-gas furnace (3.619 billion cubic meter), coke gas (151 million cubic meter), biogas (12.795 million cubic meter) and LPG (2,800 cubic meter). Additionally, there were contributions from energy sources such as: petroleum coke, water, wind, residual gas, sweet gas, solid wastes, black liquors and residual thermal energy.

2.4.5. Power sector energy sources consumption

Table 2.20 shows the country's total primary energy consumption for the most recent years. For example, during year 2000, the country's consumption was of 6,442.37 PJ of which the Power Sector (Table 2.25) consumes 1,989.68 PJ producing 693.40 PJ of electricity (equivalent to an amount of gross power generation of 192.26 TW·h). For the first time, the Energy Balance shows the fuels consumption and electricity generation of the Public System and the Electricity's Independent Producers (PIE by their Spanish initials) that are connected to the National Interconnected Grid.

Fossil fuels (coal, fuel oil, diesel and natural gas) account for the 75.20% of the total consumption of the power sector; nuclear (4.54%); hydro (17.19%); geothermal (3.07%) and wind in a very small amount (less than 1%). In year 2000, as in all the years, the structure of the fossil fuels mix is dominated by the fuel oil (47.98%) followed by natural gas (16.76%), coal (9.20%) and diesel (1.26%). Therefore, Mexican power system rests, strongly, on fossil fuels and, as a consequence it becomes an important contributor to the global emissions of the country.

Table 2.23. Total electricity generations

	1997		1998		1999		2000		2001	
	GW·h	%	GW·h	%	GW·h	%	GW·h	%	GW·h	%
Hydro	**26 431.00**	**17.14**	**24 616.00**	**15.08**	**32 713.44**	**19.07**	**33 074.88**	**18.17**	**28 435.31**	**15.54**
Thermal	**134 951.00**	**87.49**	**146 722.00**	**89.87**	**148 197.79**	**86.39**	**158 343.56**	**87.00**	**164 075.18**	**89.67**
Steam	82 103.00	64.19	86 206.00	62.12	85 103.95	61.11	89 890.87	60.18	90 394.52	58.35
Combined cycle	11 233.00	8.78	13 184.00	9.50	15 526.36	11.15	16 417.16	10.99	20 788.59	13.42
Turbo gas	657.00	0.51	1 087.00	0.78	2 076.90	1.49	5 228.11	3.50	5 456.93	3.52
Internal combustion	460.00	0.36	314.00	0.23	381.55	0.27	420.13	0.28	465.88	0.30
Geothermal	5 466.00	4.27	5 657.00	4.08	5 623.10	4.04	5 901.28	3.95	5 566.76	3.59
Dual	7 001.00	5.47	12 692.00	9.15	11 233.74	8.07	13 569.12	9.08	14 109.24	9.11
Coal	17 575.00	13.74	17 957.00	12.94	18 250.60	13.11	18 695.96	12.52	18 566.98	11.98
Nuclear	10 456.00	8.17	9 625.00	6.94	10 001.59	7.18	8 220.93	5.50	8 726.28	5.63
Wind	**4.00**	**0.00**	**5.00**	**0.00**	**6.15**	**0.00**	**7.62**	**0.00**	**6.51**	**0.00**
Total NES	**161 386.00**		**171 343.00**		**180 917.38**		**191 426.06**		**192 517.00**	
PIE	**249.00**		**765.00**		**878.00**		**837.00**		**2 958.58**	
Total	**161 635.00**		**172 108.00**		**181 795.38**		**192 263.06**		**195 475.58**	

Note: The data for year 2001 is a Table's author estimation based on the National Energy Balance 2001, Secretaría de Energía, México

NES: National Electric System

Source: JQM, prepared on the basis of the Informe de Operación 1997-2000, Comisión Federal de Electricidad, México

Country's actual energy policy privileges power generation through natural gas in detriment of fuel oil and nuclear. In this aspect, two independent prospective studies (SE, 2000; Quintanilla, 1999) indicate an important increase in the contribution to the power generation from natural gas and, also important, a reduction in fuel oil contribution. Natural gas increase is projected, mainly, through combined cycle generation technologies. Fuel oil reductions include the conversion to natural gas of eight fuel oil power plants (4,051 MW) and a dual power plant to imported coal (presently, Petacalco's power plant consumes fuel oil); all of them located in environmentally critical areas (Appendix I).

Therefore, their conversion obeys to environmental and, in some cases, to economical reasons. However, due to the recent escalation of natural gas prices it becomes necessary to review this electric expansion policy, as well as the natural gas policy, and reevaluate the contribution of fuel oil, nuclear and other options.

2.4.6. *Power sector transmission lines*

Table 2.26 describes the length of transmission lines of state-owned companies. The total length comprises its data in transmission, sub-transmission and distribution. The lines operate at tension levels of 2.4 to 60 kV, 69 to 161 kV, 230 kV and 400 kV.

Table 2.24 Net power generation and total electric energy to end-users

	1997		1998		1999		2000		2001	
	GW·h	%	GW·h	%	GW·h	%	GW·h	%	GW·h	%
Hydro	**26 331.00**	**17.07**	**24 486.00**	**15.00**	**32 274.97**	**18.81**	**32 623.40**	**17.93**	**28 047.16**	**15.33**
Thermal	**127 913.00**	**82.93**	**138 768.00**	**85.00**	**139 259.37**	**81.18**	**149 367.95**	**82.07**	**154 924.96**	**84.67**
Steam	77 549.00	60.63	81 443.00	58.69	79 485.52	57.08	84 260.73	56.41	84 732.83	54.69
Combined cycle	10 990.00	8.59	12 859.00	9.27	15 099.13	10.84	16 013.81	10.72	20 277.84	13.09
Turbo gas	654.00	0.51	1 083.00	0.78	2 048.54	1.47	5 173.40	3.46	5 399.83	3.49
Internal combustion	445.00	0.35	301.00	0.22	363.70	0.26	397.48	0.27	440.77	0.28
Geothermal	5 268.00	4.12	5 452.00	3.93	5 381.68	3.86	5 628.59	3.77	5 309.53	3.43
Dual	6 578.00	5.14	11 980.00	8.63	10 476.87	7.52	12 672.41	8.48	13 176.84	8.51
Coal	16 479.00	12.88	16 823.00	12.12	16 824.23	12.08	17 326.22	11.60	17 206.69	11.11
Nuclear	9 950.00	7.78	8 827.00	6.36	9 579.70	6.88	7 895.31	5.29	8 380.64	5.41
Wind	**4.00**	**0.00**	**5.00**	**0.00**	**5.78**	**0.00**	**7.25**	**0.00**	**6.20**	**0.00**
Total NES & PIE	**154 248.00**		**163 259.00**		**171 540.12**		**181 998.60**		**182 978.31**	
Imports	**1 805.00**		**1 705.00**		**919.00**		**1 326.00**		**327.00**	
Exports	**344.00**		**272.00**		**391.00**		**446.00**		**271.00**	
Losses (trans & Dist)	**24 379**		**25 912.00**		**27 369.00**		**27 182.00**		**27 490.68**	
End use	**131 330.00**		**138 780.00**		**144 699.12**		**155 696.60**		**155 543.63**	

Note: The data for year 2001 is a Table's author estimation based on the National Energy Balance 2001, Secretaría de Energía, México

Source: JQM, prepared on the basis of the Informe de Operación 1997-2000, Comisión Federal de Electricidad, México

2.4.7. *Power sector international commerce*

There are 10 points (Cristerna, 2000) of international commerce (Figure 2.7) of electricity with the United States, Belize and Guatemala. Eight of these points are interconnections to several southern states of the United States, one to Belize and, in the future, one to Guatemala.

The interconnection points with the United Status are: California (400 MW) through the lines Miguel-Tijuana, Baja California (230 kV) and Imperial Valley-La Rosita, Baja California (230 kV); Texas (200 MW) through two lines El Paso-Ciudad Juárez, Chihuahua (115 kV); Texas (36 MW) through the line Eagle Pass-Piedras Negras, Coahuila (138 kV); Texas (100 MW) through the line Nuevo Laredo-Laredo, Nuevo León (138 kV); Texas (80 MW) through the line Falcon-Falcón, Tamaulipas (138 kV) and Texas (120 MW) through two lines Bronwnsville-Matamoros, Tamaulipas (< 115 kV). The interconnections in the south part of the country are: Belize (100 MW) through the line Belize-Chetumal, Quintana Roo (115 kV) and Guatemala (300 MW) through the line Guatemala-México (400 kV).

Table 2.25. Power sector energy mix consumption

	1997		1998		1999		2000		2001	
	PJ	%	PJ	%	PJ	%	PJ	%	PJ	%
Coal	171.547	10.36	176.112	10.02	178.69	9.61	183.055	9.20	226.992	11.29
Diesel	13.268	0.80	19.361	1.10	17.54	0.94	25.147	1.26	18.697	0.93
CFE y LFC	13.268	100.00	19.361	100.00	17.54	100.00	25.147	100.00	18.252	97.62
PIE									0.445	2.38
Fuel oil	823.131	49.72	903.743	51.44	887.531	47.74	954.587	47.98	915.191	45.50
Natural gas	207.934	12.56	246.208	14.01	272.971	14.68	333.383	16.76	404.794	20.13
CFE y LFC	207.934	100.00	246.208	100.00	272.971	100.00	323.456	97.02	369.599	91.31
PIE							9.927	2.98	35.195	8.69
Uranium dioxide	112.495	6.79	100.471	5.72	108.26	5.82	90.331	4.54	96.669	4.81
Hydro	271.153	16.38	252.956	14.40	336.146	18.08	342.066	17.19	291.822	14.51
Geothermal	56.075	3.39	58.132	3.31	57.778	3.11	61.03	3.07	57.132	2.84
Wind	0.041	0.00	0.051	0.00	0.062	0.00	0.083	0.00	0.071	0.00
Total	**1 655.644**		**1 757.034**		**1 858.978**		**1 989.682**		**2 011.368**	

CFE: Comisión Federal de Electricidad

LFC: Luz y Fuerza del Centro

PIE: Productores Independientes de Electricidad

Source: JQM, prepared on the basis of the National Energy Balances 1997-2001, Secretaría de Energía, México

In the year 2000, Mexican imports of electricity from the United States account for 1 080 GW·h, of which 929.4 GW·h came through the California-Baja California line. For reasons of stability and synchrony the El Paso, Texas-Ciudad Juárez, Chihuahua the imports through this interconnection line requires the segregation of the loads in the National Electric System. Also, during the year 2000, Mexican exports were of 461 GW·h, 27.1% to Belize and 72.9% the United States (261 GW·h to the West Texas Utilities Co and 75 GW·h utilities in California).

2.4.8. End use sectors energy consumption

Table 2.20 shows the end use energy consumption of the industrial, transport, residential, commercial, public and agricultural sectors. In addition, the lower part of the table shows, in energy terms, what is used as raw material in the PEMEX petrochemical industry and other industrial branches. The splitting of the energy consumption of the end use sectors by fuel type is discussed in the following sections.

Table 2.26. Length of electric transmission lines of state companies

	Available lines[1]			
	Total	Transmission	Sub-transmission	Distribution
	km	*km*	*km*	*km*
1980	204 715.9	18 021.3	26 000.7	160 693.9
1981	218 154.0	19 126.4	27 954.2	171 734.0
1982	342 488.0	18 774.0	29 705.0	294 009.0
1983	363 050.0	18 913.0	30 747.0	313 390.0
1984	382 068.0	19 736.0	32 047.0	330 285.0
1985	400 462.0	22 035.0	34 219.0	344 208.0
1986	414 532.0	22 557.0	33 811.0	358 164.0
1987	431 557.0	23 510.0	33 420.0	374 627.0
1988	465 728.0	25 595.0	37 258.0	402 875.0
1989	477 489.0	27 002.0	38 145.0	412 342.0
1990	489 887.0	27 433.0	38 616.0	423 838.0
1991	509 544.0	28 343.0	38 430.0	442 771.0
1992	524 886.0	28 794.0	38 542 0	457 550.0
1993	540 500.0	29 617.0	38 568.0	472 315.0
1994	553 757.2	30 412.0	39 021.6	484 323.6
1995	564 599.6	30 791.0	39 469.5	494 339.1
1996	579 042.0	31 495.3	39 655.5	507 891.2
1997	599 727.4	32 183.3	40 124.1	527 420.0
1998	615 486.2	33 442.3	41 540.9	540 503.0
1999	629 633.8	34 458.3	42 168.3	553 007.2
2000[p]	646 423.5	35 912.3	43 395.7	567 115.5

[1] Network distribution is not included. Estimated data for 1980 and 1981

[p] Preliminary data.

Source: http://www.energia.gob.mx/estadisti/electricidad/longuitud.htm

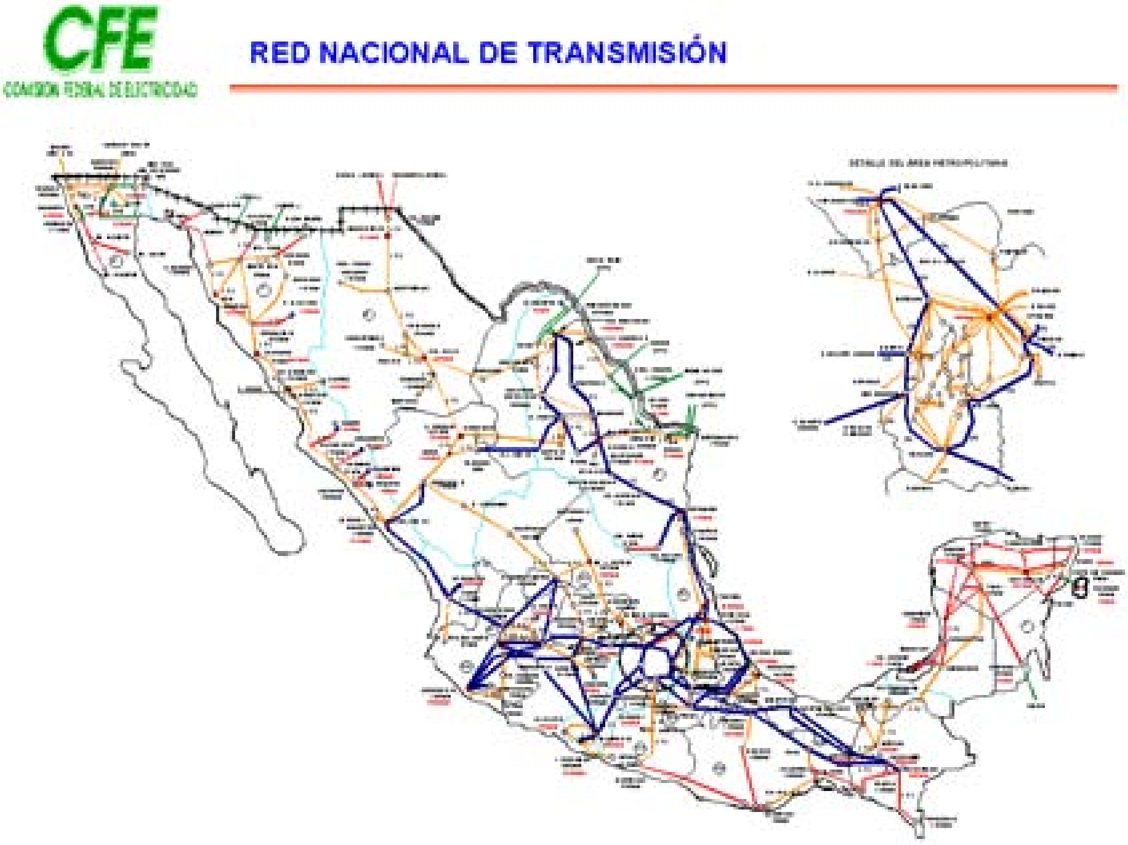

Figure2.7 National electric network.

2.4.9. Industrial sector energy consumption

Table 2.27 shows the energy consumption of the industrial sector split by type of energy source and feedstock. It is clear a systematic penetration of electricity, a decreasing pattern in the fuel oil as a result of the environmental law that limits the emissions of smoke and SO_X in the Metropolitan Areas of Mexico City, Guadalajara and Monterrey, as well as in the so called environmental critical areas located at the border with the United States and other specific regions of the country. On the other hand, diesel is reducing its share in the industrial energy consumption, whereas sugar cane bagasse shows a more or less steady pattern and coke shows an increasing participation as a result of the activity in the iron and steel industry and the industries of cement, mining and glass.

Also is clear the penetration of the LPG and natural gas. On the other hand, natural gas as raw material for the PEMEX petrochemical industry shows an important decline and non-energy products (greases, lubricants, asphalts, etc) an oscillating pattern.

For the development of the energy projections and related items, Chapter 3 the industrial sector will be split into 17 sub-sectors (PEMEX petrochemicals, iron and steel, chemicals, sugar, cement, paper and cellulose, glass, fertilizers, malt and beer, mining, bottled soft drinks, construction, automotive, rubber, aluminum, tobacco and others). The detailed energy data for these sub-sectors is reported in Appendix II.

2.4.10. *Residential sector energy consumption*

In the case of the residential sector, Table 2.29, the most important energy source is the LPG followed by the firewood, electricity natural gas and kerosene. Presently, there is a natural gas policy looking for an important penetration of this energy source in the residential sector in substitution of LPG.

Table 2.28. Transport energy consumption by type of energy source

Energy source	1997	1998	1999	2000	2001
	PJ	PJ	PJ	PJ	PJ
LPG	19.067	19.706	35.344	45.241	46.895
Gasoline	959.136	984.225	957.096	997.868	1 015.891
Kerosene	97.981	108.119	114.394	115.107	113.016
Diesel	396.683	408.968	428.792	439.155	411.869
Fuel oil	1.687	2.643	8.424	12.792	8.082
Natural gas			0.345	0.208	0.484
Electricity	3.588	3.600	3.645	3.961	4.071
Total	1 478.142	1 527.261	1 548.040	1 614.332	1 600.308

Source: JQM, prepared on the basis of the National Energy Balances 1998-2001, Secrertaría de Energía, México.

Table 2.29. Residential sector energy consumption by type of energy source

Energy source	1997	1998	1999	2000	2001
	PJ	PJ	PJ	PJ	PJ
Firewood	246.538	248.021	251.898	253.868	255.844
LPG	307.356	322.021	286.474	292.743	282.942
Kerosene	2.059	1.592	1.565	1.359	1.588
Natural gas	35.193	32.263	25.585	27.472	29.712
Electricity	106.715	114.084	120.136	130.061	138.038
Total	697.861	717.981	685.658	705.503	708.124

Source: JQM, prepared on the basis of the National Energy Balances 1998–2001, Secrertaría de Energía, México.

As in the case of the industrial and transport sectors, for the development of the energy projections and related items, the residential sector will be split into end uses (cooking, water heating, lighting, refrigeration, electro domestic appliances and air conditioning).

2.4.11. *Public and services sector energy consumption*

According to the provided by the National Energy Balance, the energy consumption of the public and services sector, Table 2.30, is represented by the electricity consumption of the lighting and water pumping activities.

2.4.12. Commercial sector energy consumption

For the commercial sector, Table 2.31, the most important energy source is LPG followed by electricity and diesel. Up to 1998, fuel oil was an important energy source, however, due to environmental considerations its use has been omitted in this sector, in especial within the environmental critical areas (APPENDIX I).

Table 2.30. Public and Services sector energy consumption by type of energy source

Energy source	1997	1998	1999	2000	2001
	PJ	PJ	PJ	PJ	PJ
Electricity	18.346	18.637	19.555	21.143	21.503
Total	18.346	18.637	19.555	21.143	21.503

Source: JQM, prepared on the basis of the National Energy Balances 1998–2001, Secretaría de Energía, México.

Table 2.31. Commercial sector energy consumption by type of energy source

Energy source	1997	1998	1999	2000	2001
	PJ	PJ	PJ	PJ	PJ
LPG	55.218	57.853	56.790	63.342	64.955
Diesel	1.827	3.439	3.529	3.560	3.375
Fuel oil	31.914	33.116			
Electricity	35.589	37.843	39.470	42.088	43.801
Total	124.548	132.251	99.789	108.990	112.131

Source: JQM, prepared on the basis of the National Energy Balances 1998–2001, Secretaría de Energía, México.

Table 2.32 Agricultural sector energy consumption by type of energy source

Energy source	1997	1998	1999	2000	2001
	PJ	PJ	PJ	PJ	PJ
LPG	1.153	1.258	8.472	7.533	8.974
Kerosene	4.020	0.040	0.053	0.057	0.039
Diesel	74.201	77.389	79.568	79.481	74.513
Electricity	27.544	27.875	28.786	28.444	26.867
Total	106.918	106.562	116.879	115.515	110.393

Source: JQM, prepared on the basis of the National Energy Balances 1998-2001, Secretaría de Energía, México.

2.4.13. Agricultural sector energy consumption

In the case of the agricultural sector, Table 2.32, the most important energy source is the diesel, which shows a more or less steady pattern, followed by electricity also with a steady pattern, an increasing pattern of LPG and a decreasing one in the case of kerosene.

Finally, in the Appendix C the reader will find a presentation of the current organization and policies in the energy sector, as well as, energy planning procedures in the oil and electric sectors. Appendix I contains a presentation of the environmental legislation and policies related to the use of energy in the sectors.

3. METHODOLOGICAL APPROACH

The Mexican study was carried out by using the combination of a set of energy models that were provided by the International Atomic Energy Agency and Argonne National Laboratory, and a national model as can be presented in the Figure 3.1.

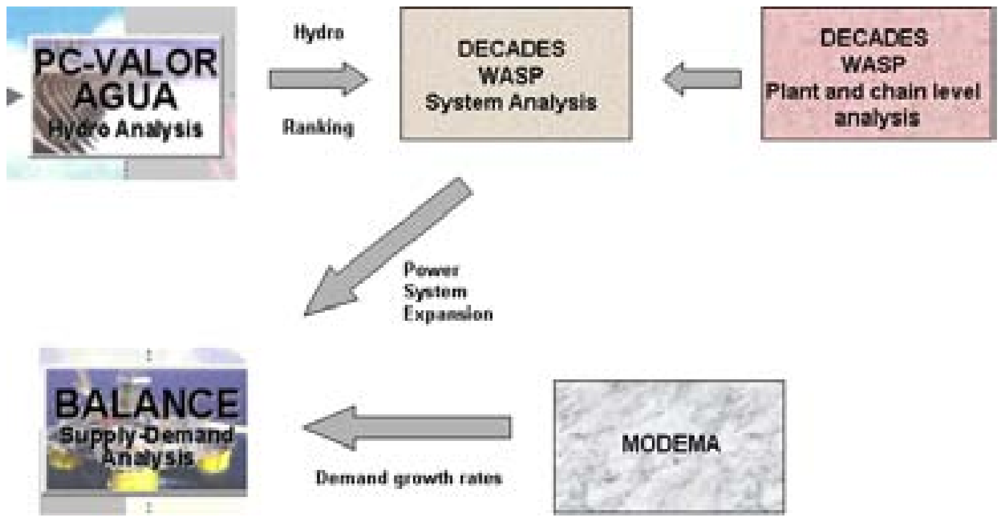

Figure 3.1. Energy models for the study

3.1. VALORAGUA Methodology

The PC-VALORAGUA model was used to determine the optimal strategy of mixed hydrothermal electric power systems by ranking them. Its goal is to determine the optimal operational strategy for a mixed power system configuration, taking into account the most important constraints and uncertainties that characterize the operation of hydrothermal power systems. It is not intended for optimization of the future investments in power generation from year to year. However, this program, when is used together with WASP program, allows for economic optimization of hydrothermal power systems with a large hydro component. VALORAGUA finds the most economical operation strategy of a thermal and hydroelectric power system, taking into account the physical and operational constraints and random conditions of the system operation, for a given configuration of an electric power system. The optimal operation strategy is obtained for the system as a whole, with an emphasis on detailed simulation and optimization of the hydro subsystem operation. The model can simulate the operation of all types of hydropower plants (run-of-river, weekly, monthly, seasonal, or multi-annual regulation), including pumped-storage plants and multipurpose hydro projects.

3.2. WASP Module

The WASP (/DECADES) model (Wien Automatic System Planning Package) was used to determine the power sector expansion and estimate unit generation and fuel consumption levels. WASP helps to find the economically optimum expansion plan for a power generating system for up to 30 years, within constraints specified by the planner. The model determines an electric system expansion plan that meets the growing demand for electricity at minimum cost while respecting user-specified constraints, such as desired system reliability, fuel limitations, or environmental constraints. The optimum is evaluated in terms of the minimum present worth of total system expansion and operating costs. WASP uses probabilistic simulation of production costs, energy-not-served costs, and system reliability parameters to compare total costs of alternative expansion policies. Each possible sequence of power units added to the system (expansion plan or policy) that meets the constraints specified by the user is evaluated by a cost function (the objective function). The optimal expansion path is then determined using a dynamic programming algorithm. For the analysis of mixed hydrothermal power systems, WASP is frequently used in combination with the PC-VALORAGUA model. The expansion analysis conducted with the WASP/VALORAGUA methodology provides an enhanced representation of hydro power plants and their operation in the electric power system.

3.3. DECADES methodology

DECADES model was used for the first phase of the project, entitled: "Comparative Assessment of Energy Sources for Electricity Supply until 2025" (see Chapter 6 for the discussion and results) and its results of the power system expansion analysis were transferred to ENPEP model.

DECADES stands for an integrated software package of databases and methodologies for comparative assessment of different energy sources for electricity generation. It was developed to provide senior analysts and energy planners with an easy to use tool for carrying out decision support studies for the power sector. This tool consist of: 1) databases providing a set of technical, economic and environmental data for energy chains that use fossil fuels, nuclear power and renewable energy sources for electricity generation; 2) a data management system; 3) an analytical software designed to access the information stored in the databases for analysis of costs and environmental burdens at the power plant, full energy chain and electric levels and 4) a decision analysis tool.

The DECADES tools support three levels of analysis:

- Plant level analysis is used for preliminary screening of different electricity generation options. Emission factors for main air pollutants are estimated base on fuel characteristics and power plant performances. A modular representation of pollution abatement technologies allow for user specification of appropriate abatement technology effects on capital costs, fixed and variable operating and maintenance costs, plant capacity, plant efficiency, reagent consumption and waste generation. Simple cases can be defined to compare power plants in terms of annual electricity costs, air emissions (direct and associated to materials used in construction and commissioning of power plants); solid waste generated and land use.

- Chain level analysis provides general data and analysis sufficient to present a broad view of the major trade-off between technical, economic, health and environmental aspects of energy chains. It supports the comparative assessment of full energy chains for electricity generation, from resource extraction to waste disposal. A flexible interface facilitates rapid construction of energy chain representation. Chain level results include: mass flow of fuels and waste, levelized cost of electricity generation and quantities of environmental burdens such as air pollution and total greenhouse gas emissions (CO2 equivalent), water effluents, solid waste generation and land use. Environmental burdens from auxiliary materials such as electricity, fuels, and material of construction and dismantling are also calculated. Direct comparisons of different energy chains are possible using a side-by-side display, combined with simple access to emissions, residuals and economic data. Scenarios, in which a given mixture of energy chains meets a fixed demand, can be established and evaluated in terms of annual air emissions, solid waste and land use.

- System-level analysis allows users to quickly screen electric generation system expansion strategies and to conduct comprehensive studies to develop mixes of energy chains, which meet electricity demand for a country or region. The system level planning tool contains three electric system analysis options, ranging from preliminary analysis tools based on screening curves to sophisticated least cost optimization with dynamic programming. It has core features derived from the IAEA's WASP model with an enhanced graphical interface, improved computation of environmental residuals (e.g. air pollutant emissions, land use and waste generation) and extensive reporting capabilities. The environmental residuals are estimated taking into account the full energy chains composing the system. The cost effectiveness of different air pollutant abatement strategies is also estimated.

3.4. MODEMA methodology

MODEMA model [Quintanilla, 1999] was used to develop the energy demand projections. MODEMA is an energy demand model whose projections consider the detailed behavior of the main energy consuming sectors and sub-sectors, as well as their projected consumptions and diversification possibilities. The model was developed by the Dirección General de Servicios de Cómputo Académico (DGSCA) and Programa Universitario de Energía (PUE), both institutions of the Universidad Nacional Autónoma de México (UNAM).

MODEMA is as a top-down simulation model for the primary and final energy demand. As a simulation model, the size and the sectoral structure of the energy demand are determined by the evolution of:

- The determining variables that, as a set, define the behavior of the socioeconomic activity, and
- Their causal relation with the energy demand.

The model breaks up the economy into sectors and sub-sectors, as shown in Figure 3.2, and analyses their participation in the national economy. In this way, the future total energy demand will depend of the economy and energy expectations of each sector and upon their relative weight. As a consequence, it allows for an individual analysis of the main sectors and thus gives a more representative energy demand projection than a general energy-gross domestic product (GDP) relationship.

Additionally, it has the option of introducing policy instruments, such as those seeking energy conservation and thus, of analyzing the effects of proposed policies on energy demand. Therefore the model provides the total energy demand projections and also includes the demand by type of energy source for the sectors and sub-sectors.

Table 3.1 shows the sectors, sub-sectors, energy sources, feed stocks and emissions that are included in the model. The energy sector incorporates its own consumption plus transport losses, distribution and storage. The industrial sector includes 17 industrial sub-sectors and includes the sources for energy consumption as well as those that are used as raw materials. The usually aggregated residential, commercial and public sector is split into its three components and the public sector includes the area of services. The transport sector is split into five sub-sectors. The table also shows the fuels, raw materials and emissions that are incorporated in the model.

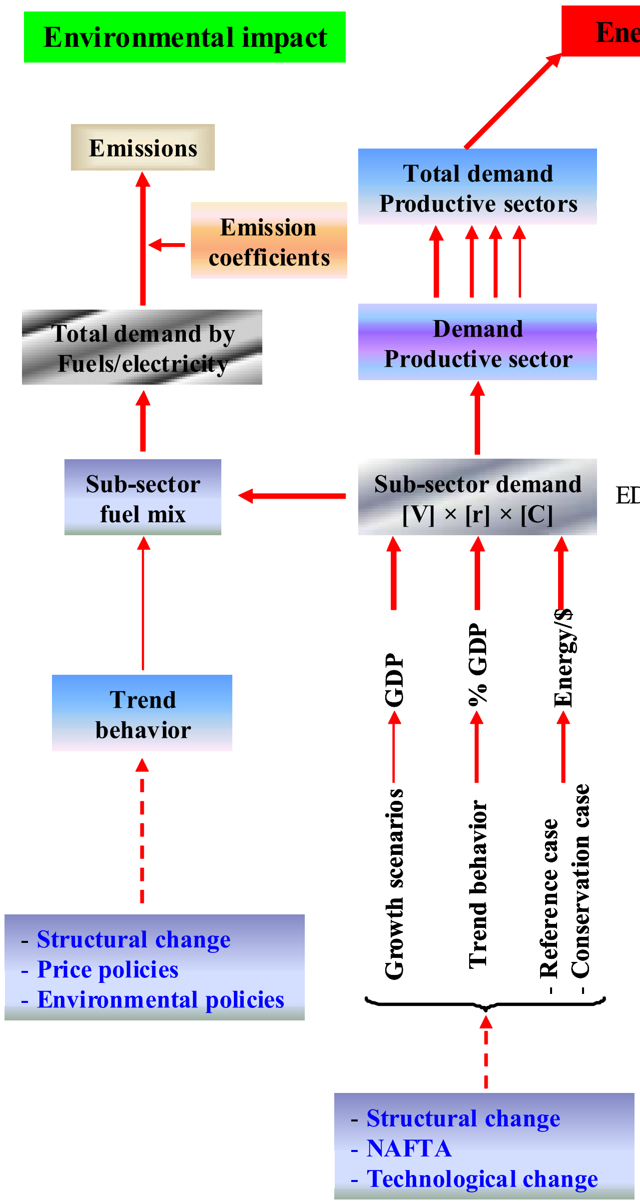

Figure 3.2. MODEMA methodology.

Once these sectors and sub-sectors are defined, the model proceeds to determine the energy indicators and the structural coefficients for each one of them for the years along the projection period. In principle, statistical fitting to their historical series carries out the time evolution of these energy indicators and structural coefficients. The model has four types of functions (linear, logarithmic, polynomial and exponential) for the fitting. The historical series for the energy indicators start from 1988 for each of the sectors and sub-sectors. The functional fitting is carried out in all cases.

Briefly, the sectors of the economy are divided into net productive and net consumer ones. The total energy demand is given by:

$$\mathbf{E}(t) = \mathbf{E}^{p}(t) + \mathbf{E}^{c}(t)$$

where $\mathbf{E}^{p}(t)$ and $\mathbf{E}^{c}(t)$ are given by:

$$\mathbf{E}^{(p,c)}(t) = \sum_{\alpha} \mathbf{ED}_{\alpha}^{(p,c)}(t) = \sum_{\alpha\mu} \mathbf{ED}_{\alpha\mu}^{(p,c)}(t)$$

Table 3.1. Sectors, sub-sectors, energy sources, feed-stocks and emissions

	Oil sector	**Energy sources**	**Emissions**
Energy sector	Electrical sector		
	Coal sector	Coal	CO_2
		Oil	CO
Agricultural sector		Condensates	CH_4
		Non associated gas	SOx
Residential sector	Urban	Associated gas	NOx
	Rural	Sugar cane bagasse	HC
		Fuel wood	Particles
Commercial sector		Coke	Others
		LPG	
	Road	Gasoline and naphtha	
	Air	Kerosene	
Transport sector	Rail	Diesel	
	Sea	Fuel oil	
	Electric	Natural gas	
		Electricity	
		Uranium	
	PEMEX petrochemicals	Geothermal	
	Iron and steel	Hydro energy	
	Chemicals	Wind	
	Sugar		
	Cement		
	Paper and cellulose		
	Glass		
	Fertilizers	**Feedstock**	
Industrial sector	Malt and beer		
	Mining	Coke	
	Bottled soft drinks	LPG	
	Construction	Gasoline and naphtha	
	Automotive	Kerosene	
	Rubber	Fuel oil	
	Aluminum	Natural gas	
	Tobacco	Sugar cane bagasse	
	Others	Non energy products	

The index α refers to the sector and the index μ to the sub-sectors (see Table 0.1); and

$$ED^{(p,c)}_{\alpha\mu}(t)=V^{(p,c)}(t) \times r^{(p,c)}_{\alpha\mu}(t)\times c^{(p,c)}_{\alpha\mu}(t)$$

For the productive sector side:

$\mathbf{V}^{\mathbf{p}}(t)$ is taken as the GDP for the year under consideration;

$\mathbf{r}^{\mathbf{p}}_{\alpha\mu}(t)$ is the contribution of each sub-sector to the GDP; and

$\mathbf{c}^{\mathbf{p}}_{\alpha\mu}(t)$ is the corresponding energy intensity, i.e. the energy used per unit product value.

For the consumer sector side:

$\mathbf{V}^{\mathbf{c}}(t)$ is the total population;

$\mathbf{r}^{\mathbf{c}}_{\alpha\mu}(t)$ is the percentage contribution of the sub-sector considered; and

$\mathbf{c}^{\mathbf{c}}_{\alpha\mu}(t)$ is the corresponding energy consumption per capita.

The productive sectors and sub-sectors are characterized by their participation (%) in the GDP and their energy intensity (E/$); the second ones, namely the residential sector, by the population distribution (%) into urban and rural and their consumption per capita (E/capita). The historical and projected evolution of the population and its structure is taken from governmental data. With respect to the GDP growth, historical data is use for the model's calibration and GDP growth scenarios for the projection horizon. To obtain the demand by energy source the matrices of energy source by sector and sub-sector are used and by using the emission matrix, the emissions by source are computed, and finally the emissions associated with each sector can be aggregated.

3.5. BALANCE module of ENPEP

The ***BALANCE*** module of ***ENPEP*** model uses a nonlinear, market-based equilibrium approach to determine the energy supply and demand balance for the entire energy system. The model uses a graphical network representation of the energy system that is designed to trace the flow of all energy forms from primary resource level to final or useful energy demand. ***ENPEP*** model was used for the second phase of the project, entitled: "Comparative Assessment of Energy Options and Strategies until 2025".

The nonlinear, equilibrium BALANCE module matches the demand for energy with available resources and technologies. Its market-based simulation approach allows BALANCE to determine the response of various segments of the energy system to changes in energy prices and demand levels. The model relies on a decentralized decision-making process in the energy sector and can be calibrated to the different preferences of energy users and suppliers. Basic input parameters include information on the energy system structure; base year energy statistics, including production and consumption levels, and prices; projected energy demand growth; and any technical and policy constraints (Figure 3.3 and Figure 3.4).

Figure 3.3. BALANCE module of ENPEP.

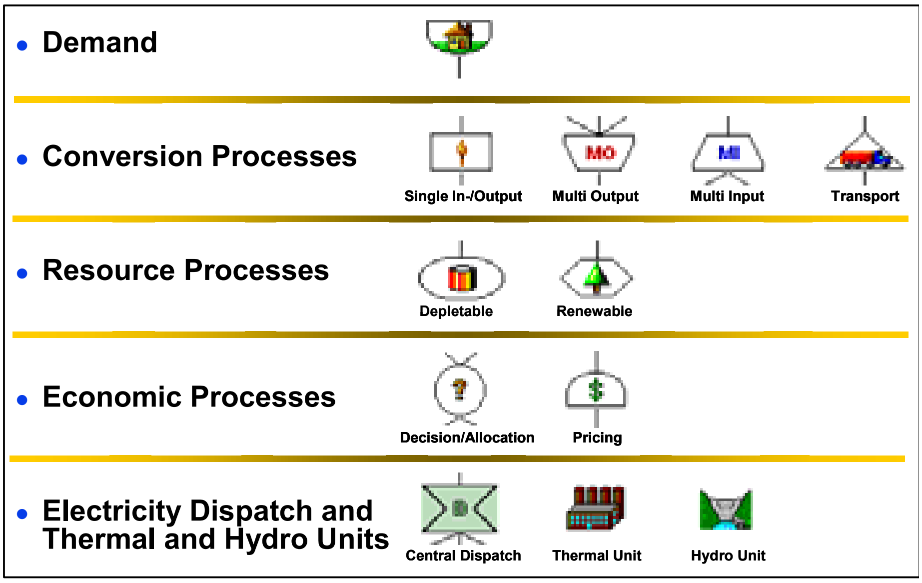

Figure 3.4. Node types available in BALANCE.

In this process, an energy network is designed to trace the flow of energy from primary resources to useful energy demands in the end-use sectors. BALANCE networks are constructed using different nodes and links, which represent various energy system components. Nodes in the network represent depletable and renewable resources, various conversion processes, refineries, thermal and hydro power stations, cogeneration units, boilers and furnaces, marketplace competition, taxes and subsidies, and energy demands.

Links connect the nodes and transfer information among nodes. BALANCE is very versatile in that the analyst starts with an empty workspace and builds an energy system configuration of nodes and links. BALANCE's powerful graphical user interface makes it is as easy as "drag and drop" to build networks of regional, national, or multinational scope. Figure 3.5 displays the sectoral energy network for Mexico and Figure 3.6 shows a detailed network for one of the seventeen industrial Mexican sub-sectors. More details on the network configuration used in this study can be found in Chapter 5.

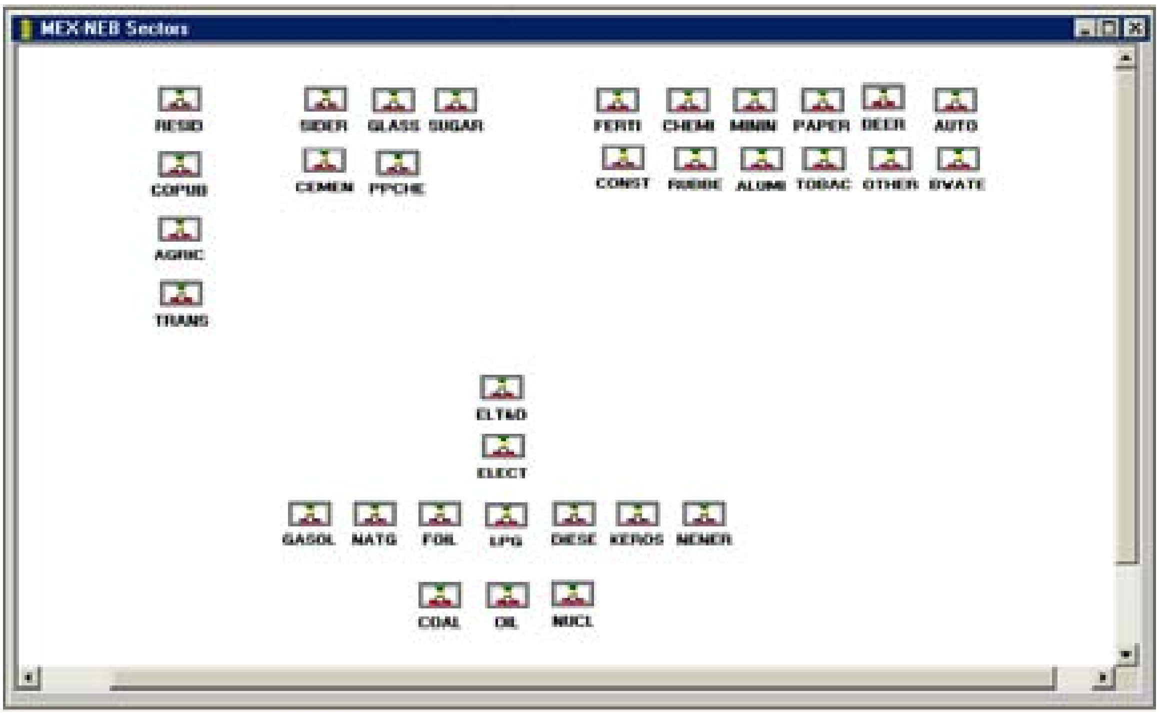

Figure 3.5. Sectoral ENPEP Network for Mexico.

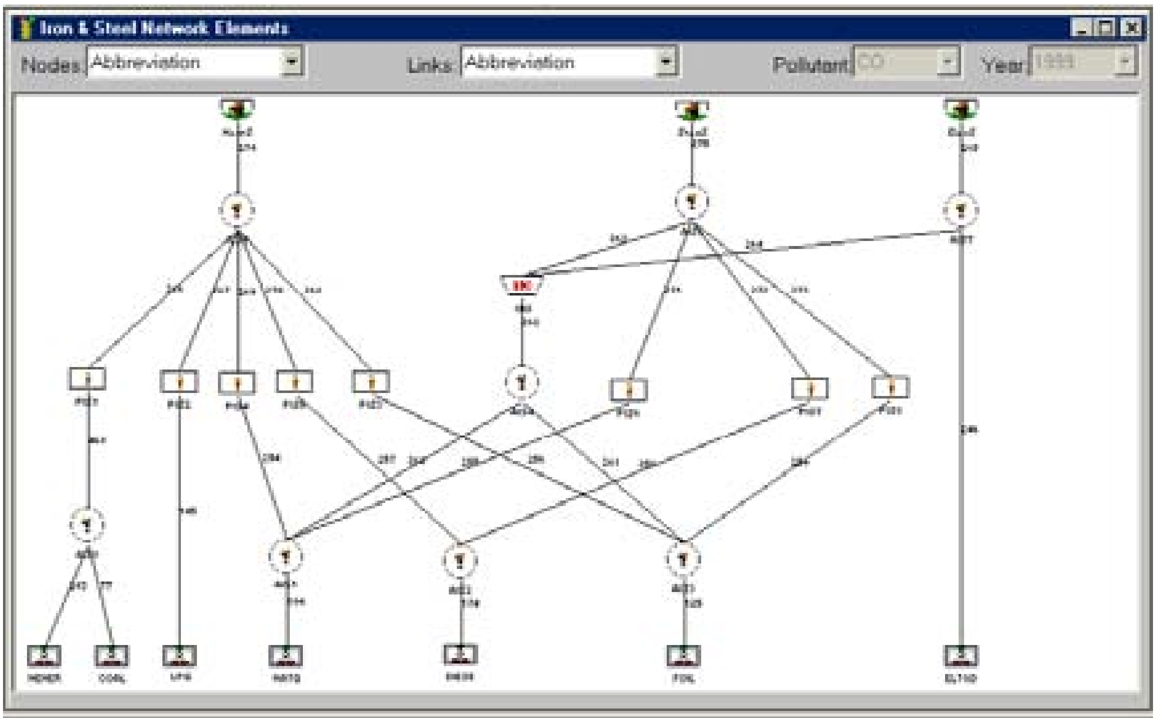

Figure 3.6. Example for industrial sub-sector Network in Mexico.

The model employs a market share algorithm to estimate the penetration of supply alternatives. The market share of a specific commodity is sensitive to the commodity's price relative to the price of alternative commodities as shown in Figure 3.7. User-defined constraints (*e.g.* capacity limits), government policies (taxes, subsidies, priority for domestic resource over imported resource, etc.), consumer preferences, and the ability of markets to respond to price signals over time (*i.e.* due to lag times in capital stock turnover) also affect the future market share of a commodity.

Using a market share algorithm distinguishes the equilibrium approach from other modeling techniques. The BALANCE approach simulates more accurately the more complex market behavior of multiple decision makers that optimization techniques may not be able to capture because they assume a single decision maker. Every sector (electric, industrial, residential, etc.) pursues different objectives and may have very different views of what is "optimum." The equilibrium solution develops an energy system configuration that balances the conflicting demands, objectives, and market forces without optimizing across all sectors of the economy.

BALANCE simultaneously finds the intersection of supply and demand curves for all energy supply forms and all energy uses included in the energy network. Equilibrium is reached when the model finds a set of market clearing prices and quantities that satisfy all relevant equations and inequalities. It employs the Jacobi iterative technique to find the solution that is within a user-defined convergence tolerance.

Concurrently with the energy calculations, the model computes the environmental residuals associated with a given energy system configuration. In addition to greenhouse gases and standard criteria air pollutants, residuals may include waste generation, water pollution, and land use. Greenhouse gas emissions can be reported in a format that is compatible with the Intergovernmental Panel on Climate Change. In this analysis, a total of 8 pollutants were implemented, however, in an effort in progress we will implement the model to include up to 30 pollutants. This includes all major GHG emissions, as well as several particulate matter (PM) species, sulfur dioxide (SO_2), nitrogen oxides (NO_X), air toxics including several species of heavy metals, and solid wastes.

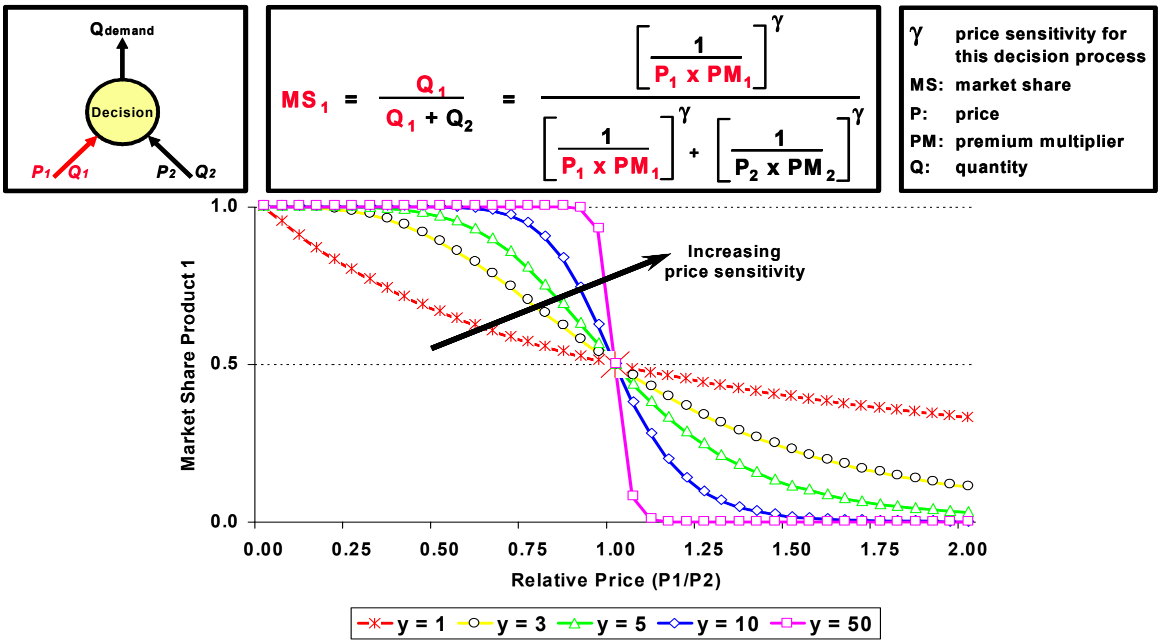

Figure 3.7. BALANCE Market Share Algorithm.

4. POWER EXPANSION ALTERNATIVES

4.1. Plant-level and system-level analysis

The National Electric System considered in the study consist of nine areas; the Interconnected System (IS) that, for operation and planning purposes is divided into six areas of control[18], and three isolated areas, Northwest, Baja California and South Baja California. These nine areas are shown in Figure 3.1. Transmission lines of 400 and 230 kV in order to share the resources of capacity and to obtain more economic and reliable operation of the electric system mainly do the interconnections between areas.

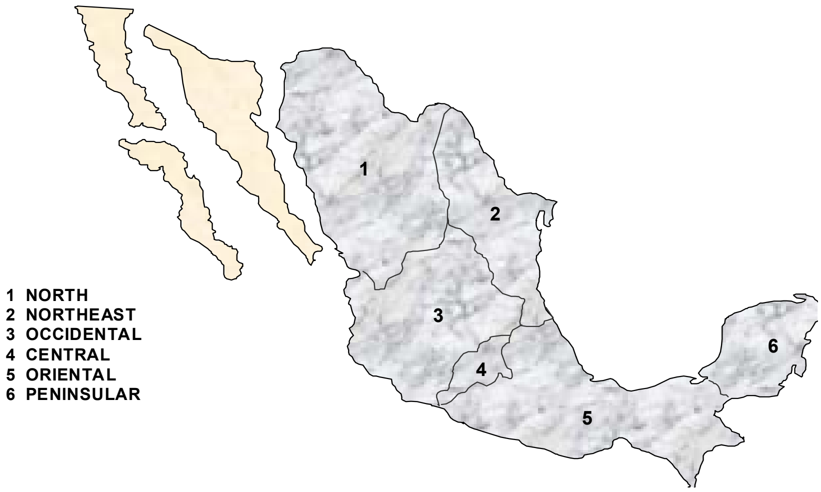

Figure 4.1. Areas of the Interconnected Power System.

For reasons of stability, the Northwest area operates independently; however, it has some links with the North and Occidental areas of the IS. These links allow for seasonal transferences of capacity. These transferences are carried out by the segregation of some generation units of the Mazatlán power utility and connecting them to the North area or by segregating some Aguamilpa's units, located in the Occidental area, and connecting them to the Northwest area.

Presently, the isolated areas of Baja California and Baja California Sur remain as independent systems, because, from the technical and economical point of view, the interconnection of them to the rest of the system it is not justified. However, the Baja California system is interconnected to the electrical grid of the Occidental region of the United States and through two transmission lines of 230 kV each one, the CFE carry commercial transactions of capacity and energy with that country.

4.2. Characterization of existing thermal power plants

4.2.1. Fuel oil and diesel plants

The thermoelectric energy generated by fossil fuels is obtained from plants of different capacities and technologies. Fuel oil plants are used, mainly, in units for base load. Fuel oil units are mostly located near ports or refineries. Natural gas is used in plants that are located near metropolitan areas like Mexico City and Monterrey; it is also used for combined cycle

[18] The interconnected system accounts for about 85% of the total generation capacity in México.

units. Diesel is used in plants that can operate during peak load periods. Among the main fuel oil plants are Manzanillo (1 900 MW) and Tuxpan (2,100 MW). Among the combined cycle plants an important one is Samalayuca II with a capacity of 521.7 MW.

4.2.2. Coal plants

Coal development is located in the state of Coahuila in the north of the country and comprises Rio Escondido plant with 1,200 MW, and Carbon II, with 1,400 MW.

4.2.3. Dual plants

Petacalco's plant is a coal plant with 2,100 MW of capacity, it has the flexibility to use fuel oil and/or coal and it is located in Guerrero State.

4.2.4. Nuclear power plant

The nuclear power plant of Laguna Verde is located in the state of Veracruz. The first unit of 654.5 MW started operation in 1990; the second one, also of 654.5 MW, started operation in 1995. Presently, the capacity of each unit is 679 MW.

4.2.5. Geothermal plants

Geothermal energy in the Interconnected System is only 17.3% of the total geothermal capacity in the country. The geothermal power plants are located in Los Azufres with 87.9 MW and Los Humeros with 42 MW.

4.2.6. Wind plants

Wind energy in the Interconnected System is a very small fraction of the total capacity in the country. The wind power plants are located in La Venta, state of Oaxaca, with 1.575 MW. The rest of the wind power capacity is located in the isolated area of Baja California Sur in the location known as Guerrero Negro with a capacity of 0.6 MW.

4.3. Engineering data of the power technologies

Table 4.1 shows the grouping of the power stations by fuel type and their associated technical parameters. The net heat rate value for each technology, in both, the fixed system and the expansion of the power sector, are taken from the COPAR of CFE. On the basis of the heating value the specific consumption is calculated.

4.3.1. Emission factors

According to the Mexican ecological standard (NOM-085-ECOL-1994), for power units burning natural gas and fuel oil or diesel with different values for the sulfur content in the fuel the emission factors are shown in Table 4.2.For other fuels, on the basis of the % in weight of sulfur in the fuel (% S), the emission factor must be calculated by using the following equation[19]:

[19] The equation is reported in the NOM-085-ECOL-1994 (Mexican Standard that regulates: smoke, total suspended particulates, sulfur and nitrogen oxides from fixed sources that use fossil fuels).

$$\textbf{Emission factor} = \frac{\dfrac{\%\,S}{100}\left[\dfrac{kg\ S}{kg\ fuel}\right]\times 2\left[\dfrac{kg\ SO_2}{kg\ S}\right]}{\text{Heating value}\left[\dfrac{10^6\,kcal}{kg\ fuel}\right]} = \left[\frac{kg\ SO_2}{10^6\,kcal}\right]$$

Table 4.1 Technical parameters and characteristics of groups for the fixed system

Power station classification	Fuel	%S	Heating value kcal/kg	Specific consumption ton (fuel)/GW·h	Net heat rate kcal/kWh
V350		3.9%	9 942.40	246.31	2 448.96
V300		3.8%	9 751.20	262.75	2 562.10
V250		4.4%	9 889.82	259.86	2 570.00
V160		3.9%	10 038.00	258.89	2 598.69
V150	**Fuel oil**	4.4%	9 889.82	267.13	2 641.91
V082		3.9%	10 038.00	297.19	2 983.21
V075		3.9%	10 038.00	297.19	2 983.21
D350		4.0%	10 061.90	243.39	2 448.96
V036		3.9%	9 942.40	359.16	3 570.95
C350		0.8%	3 863.05	650.02	2 511.06
C300	**Coal**	0.6%	4 364.45	576.73	2 517.09
DP35		1.1%	6 500.00	386.31	2 511.00
CC240		0.0%	12 171.49	180.34	2 195.02
CC220		0.0%	12 171.49	197.56	2 404.56
CC200	**Natural gas**	0.0%	12 171.49	200.60	2 441.64
CC174		0.0%	12 171.49	140.81	1 713.90
T122		0.0%	12 171.49	212.61	2 587.80
TG42		0.045%	10 845.56	342.44	3 713.98
TG30	**Diesel**	0.045%	10 845.56	396.32	4 298.36
TG14		0.045%	10 845.56	498.61	5 407.65

Source: Costos y Parámetros de Referencia, CFE, México, 1999

To convert the emission factor in kg $SO_2/10^6$ kcal to g SO_2/kWh the required conversion equation is:

$$\left[\frac{kg\ SO_2}{10^6\ kcal}\right]\times \text{Neat Heat Rate}\left[\frac{kcal}{kWh}\right]\times \text{conversion factor} = \left[\frac{g\ SO_2}{kWh}\right]$$

Table 4.2. Specific emission factor by type of fuel

Fuel	Emission factor Kg $SO_2/10^6$ kcal
Fuel oil (1% sulfur content in weight)	2.04
Fuel oil (2% sulfur content in weight)	4.08
Fuel oil (4% sulfur content in weight)	8.16
Diesel (0.5% sulfur content in weight)	0.91
Natural gas	0 (zero)

Source: Mexican ecological standard NOM-085-ECOL-1994, INE, México

For methane, particulates, CO, N_2O, HF, HCl, VOC; the emission factors are those from the publication "EPA Compilation of Air Pollutant Emission Factors Volume I: Stationary Point and Area Sources AP-42, Updated 04/28/00". Therefore, for coal fired plants we choose the emission factor associated with Sub bituminous-Fired Dry Bottom Units Tangentially Fired, for natural gas fired plants we choose the emission factor associated with Uncontrolled Industrial Large Boiler and for Fuel oil fired plants the emission factor was the associated with Uncontrolled fuel oil No. 6 Combustion Oil Fired, Normal Firing Utility Boilers.

For the emission factor of carbon dioxide a formula proposed by EPA was used. The formula corresponds to the equation associated to the Table 1.1-20 of the AP42, EPA publication. The equations look as follows:

$$\left[\frac{44\ CO_2}{12\ t\ C}\right] \times 0.99 \times \%\ C = \left[\frac{t\ CO_2}{t\ fuel}\right]$$

$$\left[\frac{t\ CO_2}{t\ fuel}\right] \times \text{Specific Consumption} \left[\frac{t\ fuel}{MWh}\right] \times \text{conversion factor} = \left[\frac{g\ CO_2}{kWh}\right]$$

In the case of combined cycle power plants, the convention of 110 *ppm* was used. It corresponds to the maximum emission solicited in the bids of the new projects. This value corresponds to the limit established by the NOM-085 for special (or critical) areas.

The conversions and units are the following ones:

$$\textbf{Existing power stations (375 ppm)} = 0.959 \left[\frac{kg\ NO_x}{10^6\ kcal}\right]$$

$$\textbf{Existing power stations (25 ppm)} = 0.0639 \left[\frac{kg\ NO_x}{10^6\ kcal}\right]$$

and to convert the emission factor in kg $NO_X/10^6$ kcal to g NO_X/kWh we have:

$$\frac{kg\ NO_x}{10^6\ kcal} \times \text{Neat Heat Rate}\ \frac{kcal}{kWh} \times \text{conversion factor} = \frac{g\ NO_x}{kWh}$$

For a quick comparison, in Table 4.3, the emission factors for SO_2, NO_X, TSP and CO_2 are showed in grams of pollutant by kilowatt-hour generated.

Table 4.3. Emission factors for power plants with control devices included

Group	Fuel	SO_2 g/kWh	NO_x g/kWh	PST g/kWh	CO_2 g/kWh
	Coal				
C350		10.66	4.68	0.6988	907.73
C300	**COAL**	6.92	4.15	0.5335	935.80
DP35		8.50	2.78	0.1178	722.18
	Fuel oil	5.31	1.46	0.3834	708.08
	Fuel oil	10.51	1.46	0.6716	708.08
	Fuel oil	21.01	1.46	1.2480	708.08
V350		11.30	1.26	0.7083	747.84
V300		19.81	1.48	1.2035	797.74
V250		22.87	1.47	1.3773	788.98
V160		20.19	1.46	1.2234	786.01
V150	**FUEL OIL**	23.51	1.51	1.4159	811.05
V082		23.18	1.68	1.4044	902.31
V075		23.18	1.68	1.4044	902.31
D350		19.47	1.37	1.1750	738.96
V036		27.66	2.03	1.6823	1 090.47
	Natural gas-existing		0.17	-	451.75
CC240		-	2.1039	-	487.06
CC220		-	2.3048	-	533.56
CC200	**NATURAL GAS**	-	2.3403	-	541.79
CC174		-	1.6428	-	380.31
T122		-	2.4804	-	574.22
	Diesel	0.28	19.71	0.6160	710.76
TG42		0.31	21.41	0.6692	1 070.28
TG30	**DIESEL**	0.36	24.78	0.7745	1 238.68
TG14		0.45	31.18	0.9743	1 558.36

The comparison of the existing technology of combined cycle with the conventional plants technology burning fuel oil (3.9% S), shows that the combined cycle technology emits 35% less CO_2 but almost 50% more NO_X emissions. On the other hand, the comparison with coal plants (0.8% S) shows that the combined cycle technology emits 55% less CO_2 and 46% less NO_X. Finally, in the case of the new dual plants, its comparison with the new combined cycles shows that they emit almost two times more CO_2 and almost six times more NO_X emissions. TSP means “Total Suspended Particles”.

4.4. Characterization of existing hydro power plants

The greatest hydroelectric development is located in the Grijalva river basin in the Southeast part of the country and is integrated by hydroelectric power plants of Angostura, Chicoasén, Malpaso and Peñitas. The total capacity as a whole is 3,900 MW, which represents 44.5% of the hydro capacity of the Interconnected System. Another important development is in the Balsas river basin, located in the south of the country. The plants in this group are: Caracol, Infiernillo and Villita, with a total capacity of 1,895 MW. The rest of hydro plants are distributed in the basins of the rivers Papaloapan, Santiago, Pánuco, Yaqui, El Fuerte, Culiacán and Sinaloa. The data for the regulation mode, regulating volume, available energy and capacity per period is detailed in the Section 3.8.

4.5. Characterization of the power plants for the expansion alternatives

In the Base Case of the study the system’s expansion is on the basis of natural gas, mainly through combined cycle units and some gas turbines. The Base Case already includes coal plants based on imported coal. The exact origin of the coal is not important for the model.

For 2024, as a time horizon, rapid unlimited expansion of natural gas increases the total capacity of the Interconnected System three-fold, from 29 GWe to 87 GWe and the capacity of gas-fired plants grows 26 times, from 2.5 GWe to 65 GWe.

The technologies selected as expansion alternatives are shown in Table 4.4. On the other hand, the specific characteristics of the technologies selected for the expansion alternatives are shown in Table 4.5.

Table 4.4. Technologies selected as expansion alternatives

Technology	Identification	Number of units	Unit capacity MW
Natural gas combined cycle	CC54	1	546
Dual fuel with desulphurization	ND35	2	350
Natural gas simple cycle	T179	1	179
Advanced boiling water reactors	N135	1	1 356

The emission factors in g/kWh for conventional plants with control devices are shown in Table 4.6. Note that only the dual technology has emissions of SO_2 and particulates, but these emissions are very small due to the fact that this technology includes abatement technologies (ESP with 99.5% of TSP and FGD with 90% of SO_2). The use of SO_2 abatement in Mexican plants is not needed because currently all plants are in compliance with the actual environmental regulation. Introducing FDG in the two existing coal plants will not change the results at the system level.

The main reason for the choosing of these alternatives for the expansion of the Mexican Electric System is the economic factor. However, other aspects become also important for the development of the power plant expansion of the electric system. Aspects, such as environmental impacts (*e.g.* lower CO_2 emissions with nuclear plants), oil derivatives and natural gas prices and energy supply diversification have an effect on the economic factor and will have to be considered in the analysis.

Table 4.6. Emission factors for fossil fuel candidate plants

Plant	Fuel	SO_2 g/kWh	NO_x g/kWh	TSP g/kWh	CO_2 g/kWh
	Coal				
ND35	**Coal**	0.88	2.88	0.1219	747.03
	Fuel oil	5.31	1.46	0.3834	708.08
	Fuel oil	10.51	1.46	0.6716	708.08
	Fuel oil	21.01	1.46	1.2480	708.08
	Natural gas-existing	-	0.17	-	451.75
CC54	**Natural gas**	-	0.4956	-	391.79
T179	**Natural gas**	-	0.7379	-	583.29
	Diesel	0.28	19.71	0.6160	710.76

In the case of the nuclear option (Table 4.7), for the generation stage, the emission factors are given for radionuclides in water and air.

4.6. Projected generation costs of power plants

4.6.1. Analysis of power system costs for thermal power plants

The investment cost of the expansion candidates is required in order to select the best technologies in the formulation of the least-cost expansion plan. The investment costs are obtained from different data sources, the most important being:

- Information about incurred costs during construction of finished power plants;
- Budgets for specific projects in construction process;
- Information from other countries; and,
- Information of equipment manufactures.

Overnight costs used in the present study are given in Table 4.8; the costs for new thermal candidates are in 1998 US dollars.

Table 4.7. Emission factors for nuclear candidate plants

Air	MBq/GWyr	Air	MBq/GWyr	Water	MBq/GWyr
Ar-41	3.60×10^{4}	Sr-89	5.87×10^{-1}	Cs-134	2.70×10^{-1}
Cr-51	1.08×10^{0}	Sr-90	5.39×10^{-2}	Cs-137	6.06×10^{0}
Kr-85m	1.23×10^{5}	Nb-95	2.85×10^{-2}	Ba-140	2.37×10^{2}
Kr-87	9.47×10^{4}	Ru-103	8.83×10^{-3}	La-140	1.00×10^{0}
Kr-88	1.05×10^{5}	Sb-125	3.91×10^{-1}	Ce-141	9.21×10^{-3}
Kr-89	5.05×10^{5}	Cs-134	2.70×10^{-1}	Kr-85	3.19×10^{5}
Xe-131m	2.18×10^{6}	Cs-137	6.06×10^{0}	Xe-133	3.39×10^{6}
Xe-135	3.03×10^{8}	Ba-140	2.37×10^{2}	I-131	8.84×10^{2}
Xe-135m	2.75×10^{6}	La-140	1.00×10^{0}	C-14	5.91×10^{5}
Xe-137	3.02×10^{5}	Ce-141	9.21×10^{-3}	Cs-137	2.91×10^{3}
Xe-138	7.59×10^{5}	Kr-85	3.19×10^{5}		
Mn-54	9.59×10^{2}	Xe-133	3.39×10^{6}		
Co-58	4.24×10^{2}	I-131	8.84×10^{2}		
Co-60	4.47×10^{0}	C-14	5.91×10^{5}		
Zn-65	4.03×10^{0}	Cs-137	2.91×10^{3}		

Table 4.8. Cost data for thermal candidates

Plant	Capacity	Depreciable capital cost	Plant life	IDC	Construction time
	MW	US$/kW	years	%	years
Gas turbine	179	346.0	30	8.08	2
Combined cycle	546	427.4	30	8.08	2
Dual coal-fired	350	1 467.9	30	15.63	4
Nuclear	1 356	2 485.4	40	29.22	8

4.7. Analysis of power system costs for hydro power plants

The study and the updating of the National Hydroelectric Potential is a permanent activity carried out by the CFE Hydroelectric Projects Management for the last 20 years. In this way, several hydro projects have been identified and analyzed with various pre-feasibility and feasibility studies in order to obtain a Catalogue of Hydroelectric Projects. The cost data for hydro power plants are listed in Table 4.9.

Table 4.9. Cost data for hydro candidates

Hydro Project Candidates *Cost in 1998 US dollars* *10% discount rate*						
	Capacity	**Annual Generation** GW·h	**Capital Cost (1)** US$/kW	**Plant Life** years	**Construction Time** years	**Interest during construction**
Hydro A						
RAFA	23	145	2 064	50	3	11.92
ACHI	900		278	50	2	8.08
CAJO	640	1 164	1 560	50	2	8.08
ATEX	120	336	1 892	50	4	15.63
TETE	609	1 312	2 201	50	5	19.21
NTUX	40	251	1 796	50	4	15.63
TEPO	330	767	1 696	50	5	19.21
SFRA	278	609	2 427	50	5	19.21
OMIT	230	789	3 436	50	4	15.63
PMON	200	292	1 019	50	4	15.63
CIUD	110	240	2 111	50	6	22.67
CARD	40	187	1 951	50	3	11.92
OSTU	206	690	3 366	50	5	19.21
AVIL	150	60	1 409	50	3	11.92
YESC	380	838	1 857	50	5	19.21
MPLA	225	505	3 366	50	4	15.63
Hydro B						
COPA	210	420	2 029	50	6	22.67
PARO	765	1 332	2 060	50	6	22.67
CHIL	28	120	1 792	50	4	15.63
ETRI	17	43	2 295	50	4	15.63
XUCH	240	691	3 104	50	5	19.21
BCDE	560	2 745	1 917	50	6	22.67
TROJ	8	41	2 548	50	3	11.92
AHON	133	292	2 399	50	4	15.63
ROSA	49	74	2 631	50	3	11.92
ELEO	29.7	64	1 227	50	4	15.63
GALL	40	134	1 699	50	3	11.92
MUCU	250	544	2 553	50	6	22.67
ITZA	340	1 520	3 366	50	6	22.67
CHIN	170	748	3 366	50	5	19.21
JILI	240	719	3 366	50	4	15.63

1 Includes direct and indirect costs and interest during construction

4.8. Analysis of fuel prices and future escalations

The suitable selection of future projects should consider the monetary flow for each technology, from the construction period until the power plant is retired. During the operation period, the most important flow component is the cost of the fuel. Table 4.10 shows the fuels prices for the years 1998 and 2027. For the expansion analysis we use the 1998 fuel price as starting value and for the rest of the projection period we affect these prices by a constant annual rate that considers the variations of these prices throughout the life's plant of the utility. The average fuel costs for 1998 entered for the expansion candidates (Table 4.4) were: 2.45 USD/GJ for natural gas (CC54 and T179), 0.53 USD/GJ for enriched uranium (N135) and 1.08 USD/GJ for imported coal (ND35).

Table 4.10. External reference fuel prices scenario (1998 dollars)

Year	Fuel oil	Natural gas	Imported coal	Enriched uranium
	barrels	1000 cf	1000 kg (0.7% sulfur)	g
1998	17.69	2.88	31.15	2.02
2027	20.70	2.95	25.99	2.34

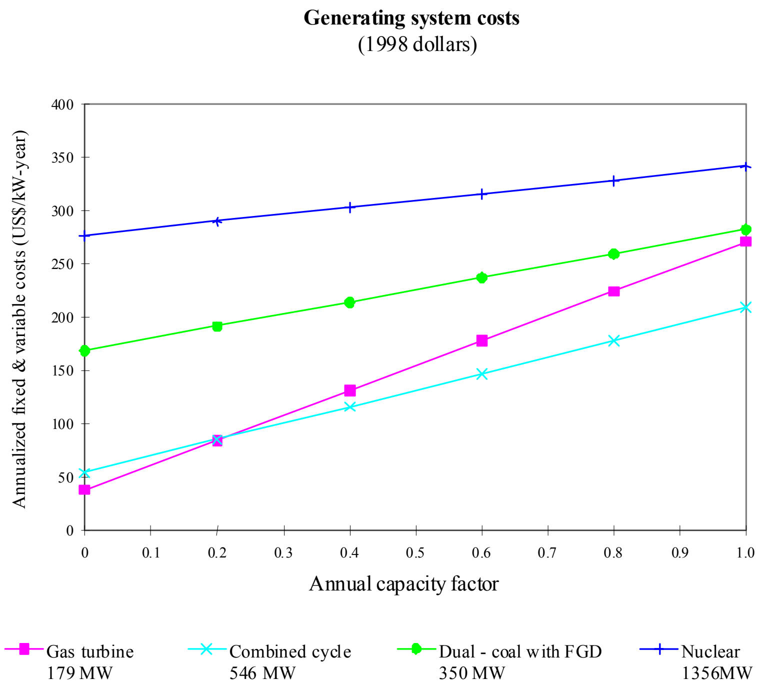

Figure 4.2. Generating system costs with a 10% discount rate.

4.9. Comparison of the expansion alternatives by a screening curves analysis

The four expansion alternatives, shown in Table 4.4, were considered for a screening curve analysis under the assumptions of 10% discount rate in the Base Case, 8 and 12% for a sensitivity analysis. For the 10% discount rate, Figure 4.2, it becomes clear that the nuclear option is always the most expensive, followed by the dual-coal unit with FGD. On the other hand, for capacity factors lower than 20%, gas turbine units are the most attractive ones. For capacity factors greater than 20%, combined cycle units are the most attractive. The other alternatives are not attractive at any capacity factor.

For a discount rate of 8%, Figure 4.3, it becomes clear that at very high capacity factors the dual plants are more attractive than the gas turbines. However, the most economic pair of candidates is the same pair of candidates as for a 10% discount rate, *i.e.* gas turbines for low capacity factors (peak loads) and combined-cycle units for high capacity factors (base loads). Finally, for a discount rate of 12%, Figure 4.4, the results are, in essence, the same as for the Base Case (10% discount rate), with small differences in the initial and final value of each candidate.

4.10. Projections of electricity demand

4.10.1. Historical evolution of the electricity demand

In Mexico, the sales of electrical energy, without considering export, changed from 92.1 TW·h in 1990 to 145 TW·h in 1999, equivalent to a growth annual average of 5.1% during the last decade. This increase in the demand of electrical energy was superior to the rate of growth of the population (an annual average growth rate of 1.8%) and to the one of the Gross Domestic Product (an average growth rate of 3.3%). The Figure 4.5 shows the correlation between the electricity demand growth rate and the GDP growth rate along the years 1970 to 1999.

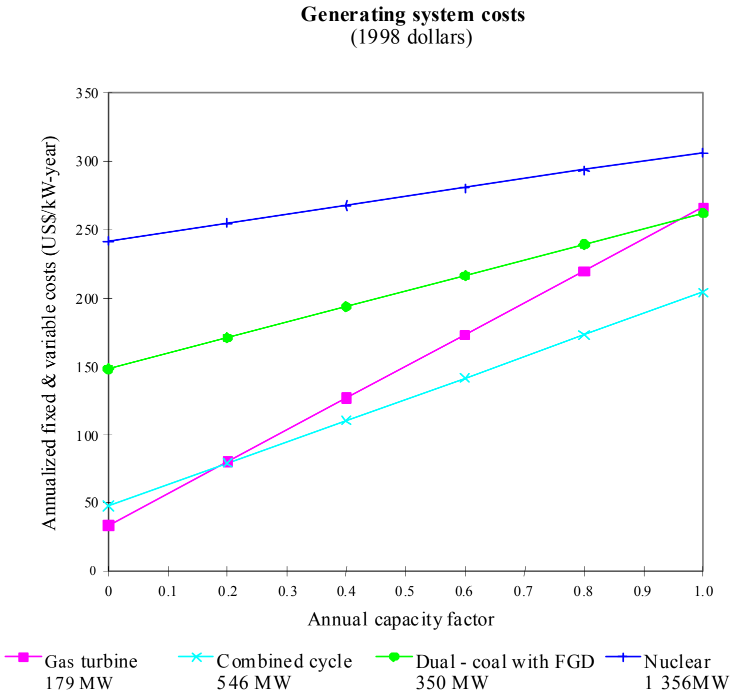

Figure 4.3. Generating system costs with an 8% discount rate.

There are several factors that explain why the growth rate of the electrical energy demand surpasses the growth rate of the GDP. One of them is that this indicator includes all the economic activities, some of which grow to a rate smaller than the rest of the economy and others growth in a more dynamic way; some of these are intensive in the use of electrical energy, as is the case of the metallurgical industry, glass industry and cement industry.

Also the population growth is translated into new users of electrical services; technological advances have lowered the price of the household-electric appliances and they have become more accessible to the general public. All this increases the demand for electricity, although the efficiency in the electrical consumption of the appliances has improved as a result of the technological advance and as a result of the development, publication and application of the national efficiency standards for end use appliances.

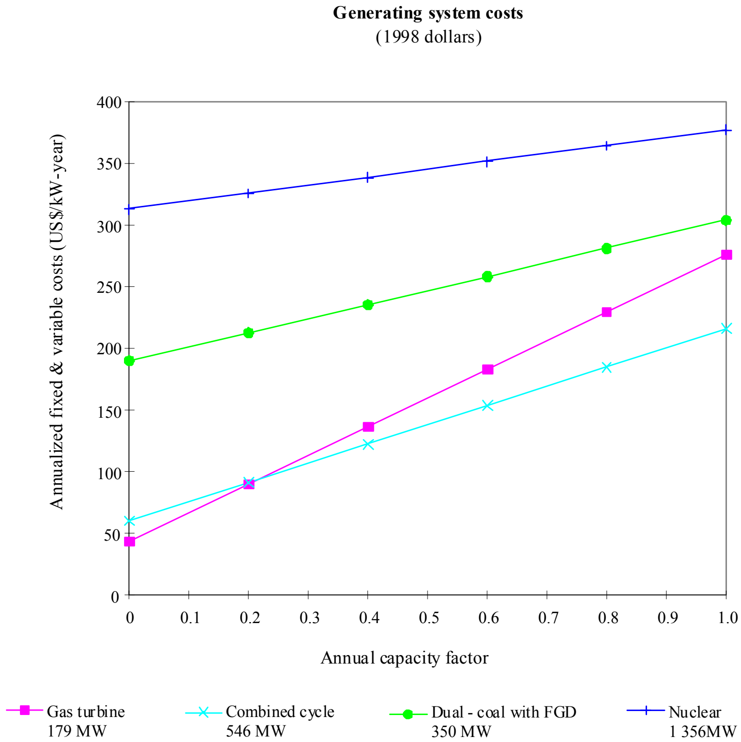

Figure 4.4. Generating system costs with a 12% discount rate.

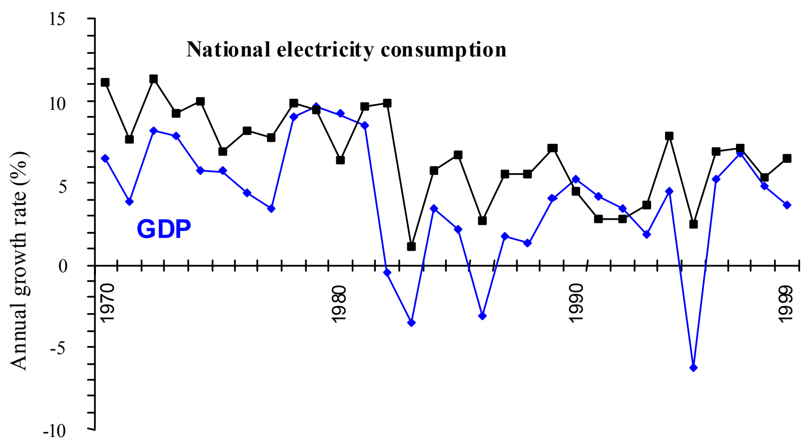

Figure 4.5. National electricity consumption and GDP growth rates, 1970–1999.

The historical evolution of the regional demand of electrical energy appears in Table 4.11, where it is observed that the regions of greater consumption of electricity during 1999 were the Western (31,724 GW·h), the Central (30,208 GW·h), the Northeast (25,629 GW·h) and the Eastern (22,983 GW·h).

Table 4.11. Total electricity sales by Region

Area	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
	GW·h	GW·h	GW·h	GW·h	GW·h	GW·h	GW·h	GW·h	GW·h	GW·h	GW·h
Northwest	6 796	7 244	7 359	7 510	7 641	8 176	8 561	9 357	9 872	10 020	10 541
Variation (%)	2.1	6.6	1.6	2.1	1.7	7.0	4.7	9.3	5.5	1.5	5.2
North	7 280	7 446	7 274	7 437	7 790	8 610	9 087	9 741	10 264	11 113	11 701
Variation (%)	11.6	2.3	-2.3	2.2	4.7	10.5	5.5	7.2	5.4	8.3	5.3
Northeast	13 479	13 947	14 760	15 720	16 274	17 801	18 675	20 490	22 209	23 746	25 629
Variation (%)	9.5	3.5	5.8	6.5	3.5	9.4	4.9	9.7	8.4	6.9	7.9
Western	16 966	18 759	19 572	19 969	21 376	23 522	24 389	26 017	27 896	29 724	31 724
Variation (%)	11.0	10.6	4.3	2.0	7.0	10.0	3.7	6.7	7.6	6.2	6.7
Central-CFE	2 484	1 174	1 296	1 250	1 400	1 610	1 824	2 265	2 510	2 527	2 645
Variation (%)	28.6	-52.7	10.4	-3.5	12.0	15.0	13.3	24.2	1.8	0.7	4.7
Central-LFC	19 578	20 527	21 128	22 569	22 955	23 914	23 465	24 055	25 461	26 499	27 563
Variation (%)	4.9	4.8	2.9	6.8	1.7	4.2	-1.9	2.5	5.8	4.1	4.0
Subtotal Central	22 062	21 701	22 424	23 819	24 355	25 524	25 289	26 320	27 971	29 026	30 208
Variation (%)	7.2	-1.6	3.3	6.2	2.3	4.8	-0.9	4.1	6.3	3.8	4.1
Eastern	15 584	16 227	16 304	15 709	16 166	17 383	18 514	19 902	21 198	22 337	22 983
Variation (%)	4.0	4.1	0.5	-3.6	2.9	7.5	6.5	7.5	6.5	5.4	2.9
Peninsular	2 073	2 295	2 541	2 668	2 869	3 169	3 233	3 264	3 652	3 961	4 169
Variation (%)	14.8	10.7	10.7	5.0	7.5	10.5	2.0	1.0	11.9	8.5	5.3
Baja California	3 640	3 826	3 849	4 065	4 129	4 588	4 870	5 606	6 184	6 347	7 020
Variation (%)	15.3	5.1	0.6	5.6	1.6	11.1	6.1	15.1	10.3	2.6	10.6
South Baja California	610	627	634	622	626	706	691	811	845	863	944
Variation (%)	7.4	2.8	1.1	-1.9	0.6	12.8	-2.1	17.4	4.2	2.1	9.4
Subtotal	**88 490**	**92 072**	**94 717**	**97 519**	**101 226**	**109 479**	**113 309**	**121 508**	**130 181**	**137 137**	**144 919**
Variation (%)	8.1	4.0	2.9	3.0	3.8	8.2	3.5	7.2	7.1	5.3	5.7
Small systems	47	51	50	51	51	54	57	66	73	71	77
Variation (%)	-2.1	8.5	-2.0	2.0	0.0	5.9	5.6	14.0	12.3	-2.7	8.4
National total	**88 537**	**92 123**	**94 767**	**97 570**	**101 277**	**109 533**	**113 366**	**121 573**	**130 254**	**137 208**	**144 996**
Variation (%)	8.1	4.1	2.9	3.0	3.8	8.2	3.5	7.2	7.1	5.3	5.7
Exports	1 932	1 946	2 019	2 041	2 015	1 843	1 861	1 179	344	76	131
Total with exports	**90 469**	**94 069**	**96 786**	**96 611**	**103 292**	**111 376**	**115 227**	**122 752**	**130 598**	**137 284**	**145 127**
Variation (%)	7.8	4.0	2.9	2.9	3.7	7.8	3.5	6.5	6.4	5.1	5.7

1 It does not includes the consumption of electrical energy generated by the permisionarios of self-supplying.

2 Isolated systems that supply to small zones or moved away populations of the national network.

3 The average rate of annual growth for period 1990-1999 calculated taking as a reference data value the value for year 1989.

For the sales figures for year 1993, an adjustment took place due to the reassignment of loads between the Western and the Central-LFC regions.

4.11. Historical system load factors and seasonal variation of peak load

The load of a system is constituted by a great number of individual loads of different classes (industrial, residential, commercial, etc.) and of small power with respect to the required total. The respective moments of connection and disconnection of these loads are random, but the required average power in a period given by the assembly of loads follows a certain pattern that depends on the rate of the human activities in the region supplied by the electrical system

Figure 4.6 shows typical average load curves for the areas of the north and the south of the country, corresponding to the working days and holidays for summer and the winter seasons of 1999. The relative magnitude of the hourly loads with respect to maximum annual demand of power is shown. It is possible to see that the load profiles depend on the geographic region, the season of the year and the working and holiday days. For example, it is observed that during the working days more electricity than in the holiday days is consumed. In the areas of the north of the country, during the summer the use of electrical energy is greater than during the winter and the peak of demand appears from 14 to 18 hours in the summer days. For the south areas we notice a slightly major consumption in the winter and the peak of the demand appears at the 20 hours in the winter days. The introduction of the hourly tariffs for the clients with larger demand has caused a change in its consumption patterns, which is reflected in the reduction of the growth rate of the peak's demand, with the consequent benefit of a better handling of the generation capacity.

4.12. System reserve and reliability

In the planning of the additions of capacity of any electrical system it is necessary to take into account the reserve's capacity that is required to guarantee reliability of the supply because:

- It is not feasible to store the electrical energy for later use, for this reason it is necessary to produce it at the moment it is required.
- The system's capacity is subject to reductions as a result of programmed exits of the plants for maintenance and fortuitous events such as faults; degradation and other causes (dry hydrologic years, etc.).

In order to satisfy the demand in suitable conditions of reliability, the capacity of the electrical system must be greater than the annual maximum demand. The reserve capacity is the difference between the capacity of the system and the maximum demand within certain period (demand tip). The reserve margin it is defined as the difference between the capacity and the maximum demand in percent of the maximum demand.

The reserve capacity of an electrical system depends on the different types of power stations that conforms it and their availability factors, of the capacity of the generating units in relation to the total, and of the conditions of the interconnection. The requirements of capacity of the weakly interconnected isolated systems or to each other are determined on an individual way, based on their own maximum demand and load curves.

When several regional systems are interconnected reliably, it is possible to reduce the reserve margin, because the resources of generation capacity can be shared in a more efficient form between the different regions; in addition, the capacity requirements can be determined by the coincident maximum demand, which is minor than the sum of the maximum demands of the regional systems, since these happen at different moments within the year (are not chronologically coincident).

There is not a unique criteria on the type of reserve margin that must be adopted in the planning of an electrical system, because in each case it depends on the accepted method for his determination, which can be probabilistic (probability of load drop), based on the cost of fault, or deterministic based on average values of availability of the generating power stations.

In 1998, the Governing body of CFE ordered the creation of a work group to analyze the situation of the supply, the demand and the margin of reserve. The work group was composed of personnel of the Ministry of Energy, Ministry of Revenue and Public Credit, Ministry of Control and Administrative Development, National Water Commission and the Federal Electricity Commission.

As a result of these meetings it was decided to adopt the deterministic criteria to establish the margin of reserve for the NES, due to its clear and simple interpretation.

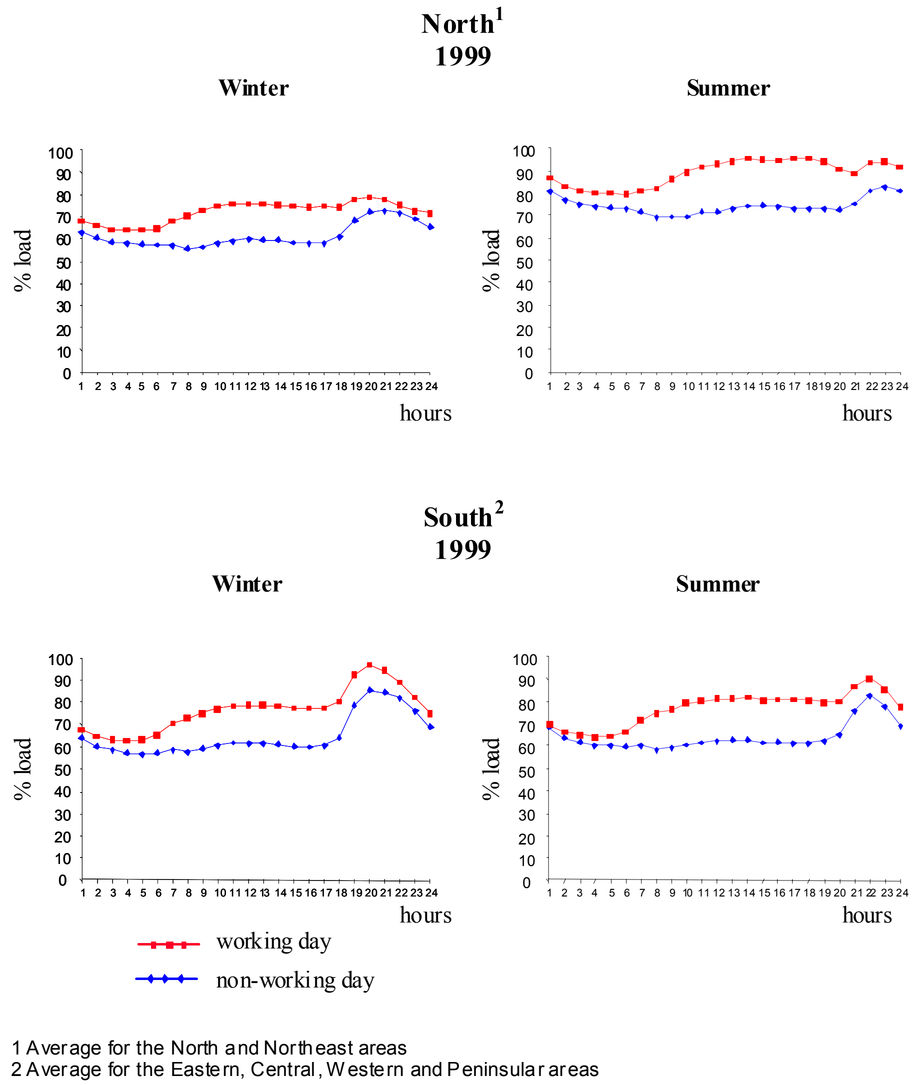

Figure 4.6. Typical load curves expressed in percentage of the annual maximum demand.

In the future and in the case of the Mexican electrical system, the reserve requirements can be influenced by the increase of the availability of the generating units and the sufficiency of the transmission networks. The concepts of reserve margin and operative reserve margin, as well as the minimum values adopted as indices associated to the expansion program, are defined in Figure 4.7.

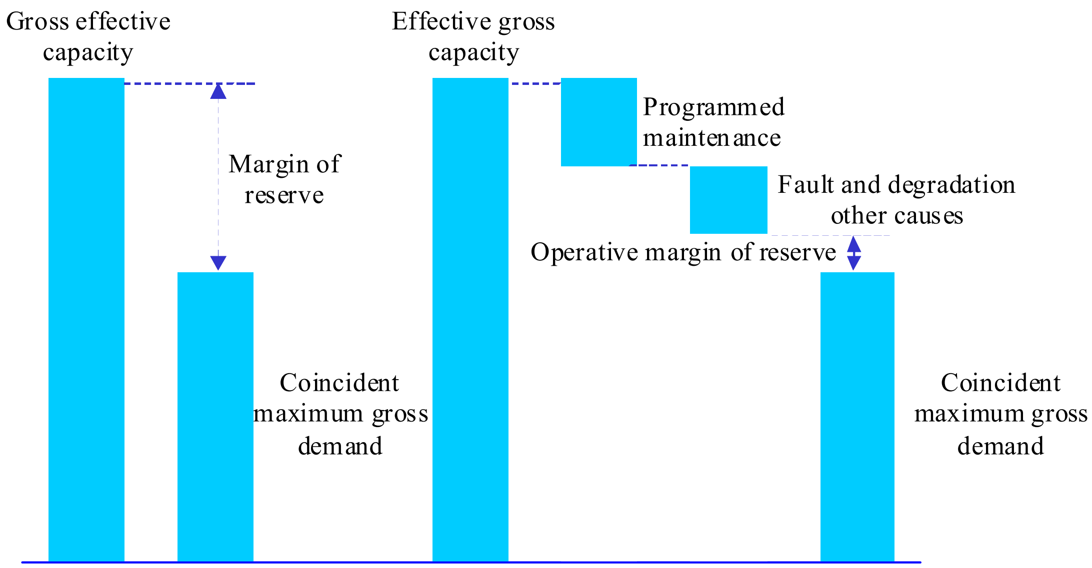

Figure 4.7. Reserve margin and operative reserve margin.

4.13. Electricity demand projections used in the study

4.13.1. Electricity demand projections

The annual values of necessary gross energy for the public service were calculated adding to the sales, the values considered for the losses of transmission and the own uses of the generation facilities and transmission. The figures corresponding to the annual maximum demand were calculated applying to the gross energy the factors of load considered for the different consumers from the region or corresponding area.

The demand of the Interconnected System (areas: North, Northeast, Western, Central, Eastern and Peninsular) in one specific hour of the year equals the sum of the demands of the areas in that same hour. For a given year, the maximum value of the hourly demands of the Interconnected System is the coincident maximum demand, which is minor than the sum of the annual maximum demands of the areas, since they happen at different moments.

The diversity factor is the relation between the sum of the annual maximum demands of the areas and the coincident maximum demand of the specific interconnected one. For a given year, the coincident maximum demand of the Interconnected System is calculated by dividing the sum of the maximum demands of the areas between the considered factors of diversity.

The total demand to be supplied by the electrical system is the demand of the public service plus the demand of the plants of self-supplying and co-generation that require services of transmission and endorsement. Table 3.12 shows the demand and peak load projections used in this study; all of them have an annual average growth rate of 5.6% along the period 1998–2024.

Table 4.12. Electricity demand projections for the Interconnected Electric System

Year	Peak load	Growth rate	Minimum load	Growth rate	Energy	Growth rate	Load factor
	MW	%	MW	%	GW·h	%	%
1998	21 236	-	9 672.8	-	145 436.5	-	78.18
1999	22 318	5.1	10 165.7	5.1	152 846.7	5.1	78.18
2000	23 540	5.5	10 722.3	5.5	161 215.6	5.5	78.18
2001	24 941	6.0	11 360.4	6.0	170 810.5	6.0	78.18
2002	26 354	5.7	12 004.0	5.7	180 487.6	5.7	78.18
2003	27 701	5.1	12 617.6	5.1	189 712.6	5.1	78.18
2004	29 182	5.3	13 292.2	5.3	199 855.3	5.3	78.18
2005	30 760	5.4	14 010.9	5.4	210 662.4	5.4	78.18
2006	32 507	5.7	14 807.0	5.7	221 946.9	5.7	77.94
2007	24 241	5.3	15 596.8	5.3	233 789.2	5.3	77.94
2008	36 075	5.4	16 432.2	5.4	246 311.3	5.4	77.94
2009	37 962	5.2	17 291.8	5.2	259 195.3	5.2	77.94
2010	39 876	5.0	18 163.6	5.0	272 263.6	5.0	77.94
2011	41 874	5.0	19 073.7	5.0	285 905.4	5.0	77.94
2012	43 929	4.9	20 009.7	4.9	299 936.5	4.9	77.94
2013	46 043	4.8	20 972.7	4.8	314 370.3	4.8	77.94
2014	48 218	4.7	21 963.4	4.7	329 220.7	4.7	77.94
2015	50 456	4.6	22 982.8	4.6	344 501.3	4.6	77.94
2016	52 710	4.5	24 009.5	4.5	359 891.0	4.5	77.94
2017	55 076	4.5	25 087.2	4.5	376 045.5	4.5	77.94
2018	57 511	4.4	26 196.4	4.4	392 671.1	4.4	77.94
2019	60 017	4.4	27 337.9	4.4	409 781.4	4.4	77.94
2020	62 596	4.3	28 512.6	4.3	427 390.2	4.3	77.94
2021	65 250	4.2	29 721.5	4.2	445 511.1	4.2	77.94
2022	67 982	4.2	30 965.9	4.2	464 164.5	4.2	77.94
2023	70 793	4.1	32 246.3	4.1	483 357.3	4.1	77.94
2024	73 686	4.1	33 564.1	4.1	503 110.0	4.1	77.94

Figure 4.8 shows the annual projected growth of the electricity demand in the period under consideration.

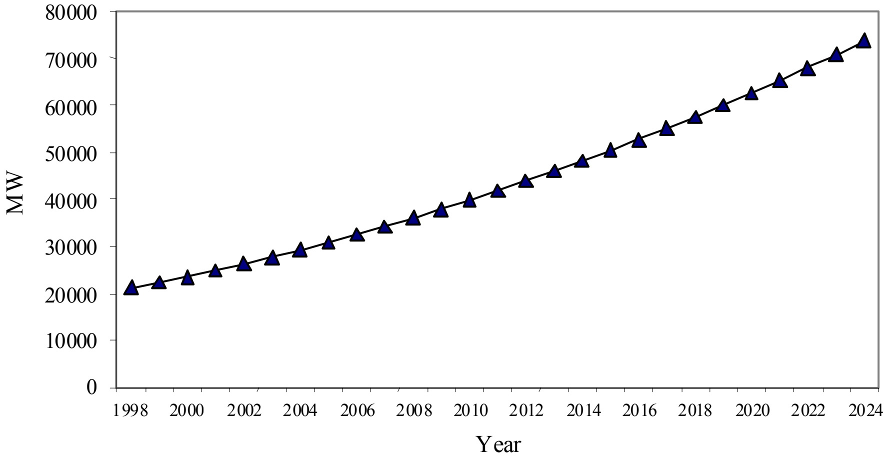

Figure 4.8. Projected growth in electricity demand.

As was mentioned in the Executive Summary of the present report, in 1998, the IAEA approved the request as a national TC project: MEX/0/012 for the 1999-2000 programme with the title "Comparative Assessment of Energy Sources for Electricity Supply until 2025". In 2000, the project was extended for 2 years (2001-2002) with a new title "Comparative Assessment of Energy Options and Strategies until 2025" with the objective to broaden the scope and analyze the entire energy system. The first phase of the project was performed using the DECADES software package.

The report presents the results of the analysis on the comparative assessment of energy options and strategies until 2025 in the entire energy system by using ENPEP (Balance) software package (Project's Phase II) while the results of the power system analysis (Project's Phase I) using the DECADES software and methodology are treated as a special chapter of the report. Regarding the Mexican Electric System, Phase I of the project consider as base year 1998 and the Mexican Interconnected Electric System, *i.e.* six interconnected areas while the Phase II of the project consider as base year 1999 and the whole Mexican Electric System, *i.e.* nine areas, the six interconnected and three isolated (Northwest, Baja California and South Baja California). Since these three isolated areas are not controlled by the National Dispatching Center its capacity and generation will have to treat as a separate part of the system. ENPEP software and methodology allows this option, however it will be necessary to have available the information for the entire system and the splitting of the generation, capacity, etc. into the interconnected system and each of the isolated areas.

4.14. Projections of the load curves

For the projection of the load curves, the 1998 load curve was taken as the load curve for the base year and used for all years. It means that there was not a real projection of the load curve, but an estimated average behavior of the curve. Figure 3.9 shows the load curves for the three quarters of a typical year.

4.14.1. Assumptions on the system's reserve and reliability criteria

For the present study the following economic and reliability parameters were used:

Discount rate	10%
ENS (cost of the Energy Not Served)	1.5 US$/kWh
LOLP (LOss-of-Load Probability)	3 days per year (0.822%)
System's Margin Reserve	10–30%

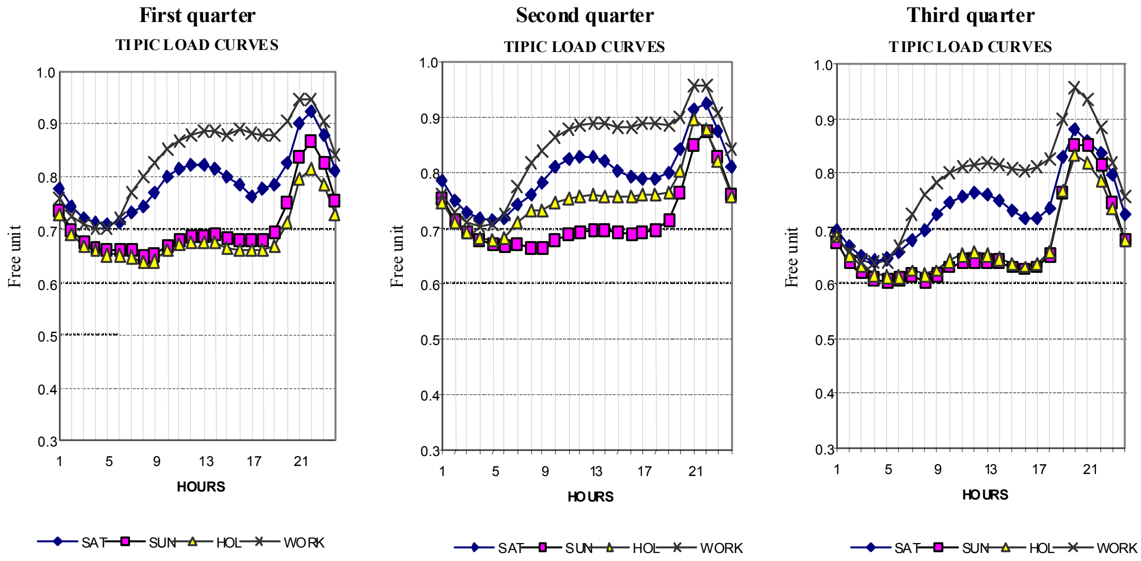

Figure 4.9. Typical load curves.

4.15. Input data for the system-level analysis

In the near future an increase in the use of oil products is expected, mainly natural gas, because of the low investment costs of the combined cycle plants and their high conversion efficiency, as well as for environmental aspects.

This expansion policy minimizes the dependency of imported sources of energy, for example, coal, if dual plants were installed. Also, in the middle term, some hydro projects are considered as expansion candidates, despite of their high investment costs, but with the purpose of an increasing level in the use of the hydro resources, to diverse the system generation expansion and to take into account environmental aspects.

4.15.1. General assumptions

The expansion of the electric system was carried out taking into account the considerations of the previous paragraph and the following general assumptions (Figure 4.10):

- The duration of the study period is 29 years, the period starts in 1999 and ends in 2027;
- The duration of the planning period is 26 years. The period starts in 1999 and ends in 2024. In this period some committed power generating plants are considered until the year 2003; and
- The period from 2025 to 2027 is considered for the "final effect" in the dynamic program in order to avoid distortions in the results.

The year is divided into three periods of four months each. The first and third periods correspond to the dry season. The second period corresponds to the raining season.

First period	March, April, May, June
Second period	July, August, September, October
Third period	November, December, January, February

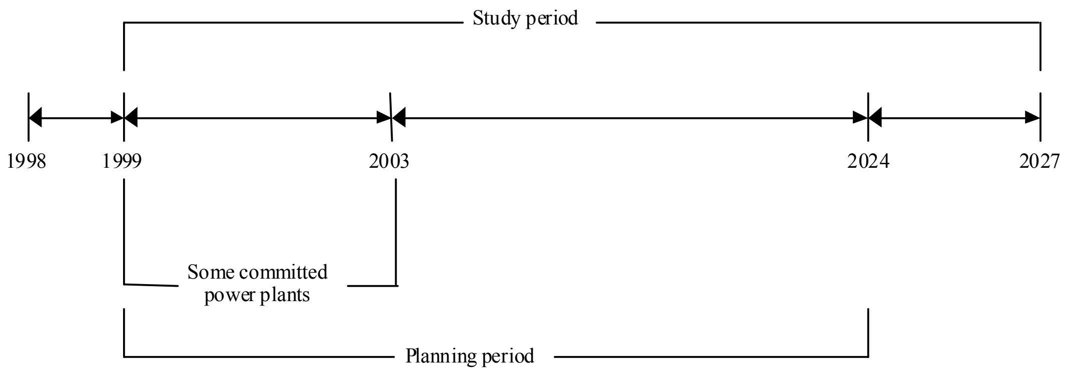

Figure 4.10. Study, planning and committed plants periods.

Three hydrological conditions are considered and their associated percentage wise probabilities are the following ones:

Dry hydrological condition	19.06%
Medium hydrological condition	58.67%
Humid hydrological condition	22.27%

These hydrological conditions are defined on the basis of the statistical-month generations of the nine greatest hydro-units in the country, which represent the 75% of the total hydro generation. The nine hydro units are: Angostura 900 MW, Chicoasén 1,500 MW, Malpaso 1,080 MW, Peñitas 420 MW, Caracol 600 MW, Infiernillo 1,000 MW, Villita 295 MW, Temascal 154 MW and Aguamilpa 960 MW.

- In accordance with the CFE studies, the Base Case discount rate is 10%. Nevertheless, sensitivity studies with discount rates of 8% and 12% were performed in order to reflect lower or higher cost of capital.
- Reliability is 3 days/year in the LOss of Load Probability (LOLP).

4.15.2. Characterization of existing and firmly committed power plants

The Table 3.13 shows the existing power generating thermal plants in 1998. They are grouped accordingly to their type of fuel, net capacity (minimum operating level and maximum generating capacity in MW), average heat rate (kcal/kWh), unit forced outage rate (%), number of days per year required for scheduled maintenance, unit spinning reserve as % of MW capacity, fuel costs (US¢/10^6 kcal), fixed component of non fuel operation and maintenance cost of each unit (US$/kW-month) and variable component of non fuel operation and maintenance cost (US$/MWh) of each unit.

This information was obtained from different CFE reports, among others there are: Unidades Generadoras en Operación, Disponibilidad e Indisponibilidad de Unidades Generadoras, Eficiencia Térmica Anual por Categoría and COPAR-Generación.

Table 4.13. Interconnected System: Existing thermal power generating units.

Interconnected System: Existing System at December 1998 Thermal power generating plants 1998 dollars											
Name	Fuel	Number	Net capacity		Net heat	Forced	Maintenance	Spinning	Fuel	Operation & maintenance cost (1)	
code	type	of units	Minimum	Maximum	rate	outage		reserve	cost	Fixed	Variable
			MW	MW	kcal/kWh	%	days/year	%	US¢/kw/month	US$/kW/month	US$/MWh
V350	Oil	10	165	330	2449	8.34	45	10.00	1117	0.938	0.120
V300	Oil	12	141	283	2562	8.34	45	10.00	1117	1.066	0.120
V250	Oil	3	118	236	2570	8.34	45	10.00	1117	1.194	0.130
V160	Oil	6	75	150	2599	8.23	45	10.00	1117	1.425	0.130
V150	Oil	7	71	141	2642	8.23	45	10.00	1117	1.478	0.130
V082	Oil	7	23	77	2983	10.41	45	10.00	1117	1.833	0.130
V075	Oil	3	21	70	2983	10.41	45	10.00	1117	2.162	0.130
V036	Oil	20	10	33	3571	11.71	45	10.00	1117	3.529	0.130
C350	Coal	4	162	323	2511	8.34	45	10.00	486	1.666	0.130
C300	Coal	4	138	277	2517	8.34	45	10.00	486	1.666	0.130
D350	Oil	6	154	308	2655	6.80	21	10.00	1117	2.212	1.150
G050	Geothermal	1	14	47	4481	9.01	18	10.00	0	20.040	0.040
G020	Geothermal	4	6	19	4481	9.01	18	10.00	0	20.040	0.040
CC240	Natural gas	2	116	233	2195	12.46	38	10.00	1112	1.620	0.360
CC220	Natural gas	3	107	213	2405	12.46	38	10.00	1112	1.620	0.360
CC200	Natural gas	4	97	194	2442	12.46	38	10.00	1112	1.620	0.360
CC174	Natural gas	3	85	171	1714	8.19	15	10.00	1112	1.620	0.360
TG122	Natural gas	1	30	121	2586	6.00	15	10.00	1112	0.410	0.100
TG42	Diesel	6	42	42	3714	6.00	0	0	1787	1.392	0.110
TG30	Diesel	16	30	30	4298	6.00	0	0	1787	1.392	0.110
TG14	Diesel	31	14	14	5408	6.00	0	0	1787	1.392	0.110
N655	Nuclear	2	551	656	2733	9.00	40	10.00	211	4.411	0.530
EO27	Wind	0	9	27		9.01	18	10.00	0	3.213	0.040

1) COPAR 1998

On the other hand, Table 3.14 shows the existing hydro plants in 1998. For each plant, the capacity and generation for the corresponding period and hydro condition is given. The Table 4.15 shows the firmly committed power generating plants in the period 1999–2003. These power plants are under construction, bidding process or under the plan of immediate action.

Table 4.14. Existing hydroelectric power generating units

Capacity in MW			
HPEQ	**897**		
	Dry humidity	Medium humidity	High humidity
MAMJ	551	647	667
JASO	564	662	683
NDJF	557	655	675
HPE2	**216**		
	Dry humidity	Medium humidity	High humidity
MAMJ	149	174	180
JASO	151	177	183
NDJF	149	175	181
GRIJ	**3900**		
	Dry humidity	Medium humidity	High humidity
MAMJ	2 697	3 485	3 595
JASO	3 086	3 625	3 740
NDJF	2 689	3 158	3 258
BALS	**1884**		
	Dry humidity	Medium humidity	High humidity
MAMJ	1 154	1 355	1 398
JASO	1 380	1 621	1 672
NDJF	1 441	1 692	1 746
TEMA	**154**		
	Dry humidity	Medium humidity	High humidity
MAMJ	83	97	100
JASO	110	129	133
NDJF	104	122	126
APRI	**240**		
	Dry humidity	Medium humidity	High humidity
MAMJ	157	184	190
JASO	191	225	232
NDJF	191	225	232
AMIL	**960**		
	Dry humidity	Medium humidity	High humidity
MAMJ	765	899	927
JASO	765	899	927
NDJF	627	737	760
ZIMA	**292**		
	Dry humidity	Medium humidity	High humidity
MAMJ	191	224	231
JASO	232	272	281
NDJF	199	234	241
TEMA2	**200**		
	Dry humidity	Medium humidity	High humidity
MAMJ	130	153	158
JASO	159	187	198
NDJF	159	187	198
TOTALS	**8743**		
	Dry humidity	Medium humidity	High humidity
MAMJ	6 145	7 218	7 446
JASO	6 638	7 797	8 044
NDJF	6 117	7 185	7 412
Annual average	**6 300**	**7 400**	**7 634**

Source: Hydroelectric Project Management, CFE, Mexico

Generation in GW·h			
HPEQ			
	Dry humidity	Medium humidity	High humidity
MAMJ	1 033	990	971
JASO	1 486	1 331	1 578
NDJF	1 141	1 075	1 120
Annual	3 660	3 396	3 669
HPE2			
	Dry humidity	Medium humidity	High humidity
MAMJ	105	91	109
JASO	248	200	263
NDJF	89	73	79
Annual	442	364	451
GRIJ			
	Dry humidity	Medium humidity	High humidity
MAMJ	3 797	4 126	4 274
JASO	1 464	3 078	5 675
NDJF	2 709	4 331	4 897
Annual	7 970	11 535	14 846
BALS			
	Dry humidity	Medium humidity	High humidity
MAMJ	2 088	1 982	2 071
JASO	1 957	2 512	3 396
NDJF	1 001	1 206	1 466
Annual	5 046	5 700	6 933
TEMA			
	Dry humidity	Medium humidity	High humidity
MAMJ	227	268	288
JASO	255	238	339
NDJF	250	239	262
Annual	732	745	889
APRI			
	Dry humidity	Medium humidity	High humidity
MAMJ	43	51	58
JASO	297	348	400
NDJF	50	59	68
Annual	390	458	526
AMIL			
	Dry humidity	Medium humidity	High humidity
MAMJ	451	369	338
JASO	1 220	1 538	1 488
NDJF	306	348	319
Annual	1 977	2 255	2 145
ZIMA			
	Dry humidity	Medium humidity	High humidity
MAMJ	328	387	440
JASO	308	363	412
NDJF	450	531	604
Annual	1 086	1 281	1 456
TEMA2			
	Dry humidity	Medium humidity	High humidity
MAMJ	165	171	175
JASO	135	172	255
NDJF	201	210	224
Annual	501	553	654
TOTALS			
	Dry humidity	Medium humidity	High humidity
MAMJ	8 237	8 435	8 724
JASO	7 370	9 780	13 806
NDJF	6 197	8 072	9 039
	21 804	**26 287**	**31 569**

Source: Hydroelectric Project Management, CFE, Mexico

4.15.3. Evolution of the "fixed system" over the study period

As was mentioned, Table 4.13 shows the fixed system in the year 1998. Along the study, the fixed system is basically affected by the retirements of those units that have reached their useful life. In order to take into account these retirements, Table 4.16 display the retirement program for these units. The units retired are mostly thermal (oil, diesel and gas). Nevertheless, also some small hydro units are retired in the year 1998, which is the first year for the Phase I of this study. For this reason, the adjustment of these hydro plants was externally performed in the HPEQ and HPE2 plants of hydro type A.

In the year 2002, CFE plans to construct a 100 MW geothermal power plant. Due to the fact that is the unique plant of this type in the CFE expansion program, it was decided to include it in the fixed system (as a project of two geothermal units of 50 MW each) with the purpose of avoiding the creation of an additional category in VARSYS of the WASP methodology.

Table 4.15. Committed power generating plants

	Type	1999	2000	2001	2002	2003
		MW	MW	MW	NW	MW
Under construction						
Mérida III (units 1 and 2)	CC		499.0			
Monterrey II	CC		489.9			
Chihuahua II	CC			417.8		
Río Bravo II	CC			511.4		
Saltillo	CC			255.7		
Tuxpan II	CC			511.4		
Bajío (El Sauz)	CC			511.4		
Under bidding projects						
Monterrey III	CC				450.0	
Altamira II	CC				450.0	
Campeche	CC				225.0	
Plan of immediate action						
Río Bravo	TG	154.2				
Huinala	TG	141.0				

4.16. Characterization of the power plants for the expansion alternatives

To select the power generating plants considered as expansion alternatives, the "COPAR-Generation" plants were used. Initially, the "Screening Curves" for each technology were performed in order to know which ones are the most attractive for the expansion (Figure 4.11). From the figure, it becomes clear that for capacity factors lower than 40% the gas turbine units are the most attractive ones. For capacity factors greater than 40%, the most attractive plants are the combined cycle.

Table 4.16. Power plants retirement program

Oil Units

Name	Unit	Capacity MW	WASP retirement	Year of retirement
Francisco Villa	U1	33		2001
Francisco Villa	U2	33		2001
Francisco Villa	U3	33		2001
Nachi-cocóm	U1	24.5		2002
Nachi-cocóm	U2	24.5		2002
San Jerónimo	U3	37.5	2003	2002
San Jerónimo	U4	37.5	2003	2002
Río Bravo	U1	37.5	2004	2003
Río Bravo	U2	37.5	2004	2003
La Laguna	U4	39	2004	2003
Poza Rica	U1	39		2005
Poza Rica	U2	39		2005
Poza Rica	U3	39		2005
Monterrey	U1	75	2007	2006
Monterrey	U2	75	2007	2006
Monterrey	U3	75	2007	2006
Monterrey	U4	80	2008	2007
Monterrey	U5	80	2008	2007
Monterrey	U6	80	2008	2007
Lerma (Campeche)	U1	37.5		2007
Lerma (Campeche)	U2	37.5		2007
Lerma (Campeche)	U3	37.5		2007
Lerma (Campeche)	U4	37.5		2007
Valle de México	U1	150		2010
Valle de México	U2	150		2011
Valle de México	U3	150		2012
Altamira	U1	150		2015
Altamira	U2	150		2015
Salamanca	U1	158		2016
Salamanca	U2	158		2016
Tula	U1	300		2017
Tula	U2	300		2017

Turbine units

Name	Unit	Capacity MW	WASP retirement	Year of retirement
Xul-ha	U1	14		2002
Cozumel móvil	U1	12.5		2002
Chihuahua	U1	14	2003	2002
Chihuahua	U2	14	2003	2002
Esperanzas	U1	12	2003	2002
Fundidora	U1	12	2003	2002
Las Cruces	U1	14		2002
Las Cruces	U2	14		2002
Las Cruces	U3	15		2002
Universidad	U1	12	2003	2002
Universidad	U2	12	2003	2002
Cancún	U1	14		2003
Cancún	U2	14		2003
Arroyo Coyote	U1	12	2004	2003
Tecnológico	U1	26	2004	2003
Chihuahua	U3	18	2005	2004
Chihuahua	U4	18	2005	2004
Industrial	U1	18	2005	2004
Parque	U3	13	2005	2004
Chankanaab	U4	25		2006
Chávez	U1	14	2007	2006
Chávez	U2	14	2007	2006
La Laguna	U1	14	2007	2006
LaLaguna	U2	14	2007	2006
Leona	U1	12	2007	2006
Arroyo Coyote	U2	12	2007	2006
Parque	U2	18	2008	2007
Parque	U4	28	2008	2007
Parque	U5	28	2008	2007
Monclova	U1	18		2008
Monclova	U2	30		2008
Cancún	U3	30		2009
Cancún	U5	44		2009
Nach cocóm	U3	30		2010
La Laguna	U3	14		2011
La Laguna	U4	14		2011
Mérida II	U3	30		2011
Nizuc	U1	44		2016
Nizuc	U2	44		2016
Leona	U2	12		2017
Cd. del Carmen	U1	14		2017

Combined cycle units

Name	Unit	Capacity MW	Year of retirement
Gómez Palacio	U1	59	2008
Gómez Palacio	U2	59	2008
Gómez Palacio	U3	82	2008
El Sauz	U1	50	2013
El Sauz	U2	50	2013
El Sauz	U3	50	2013
El Sauz	U4	68	2013
Dos Bocas	U1	63	2015
Dos Bocas	U2	63	2015
Dos Bocas	U5	100	2015
Dos Bocas	U3	63	2015
Dos Bocas	U4	63	2015
Dos Bocas	U6	100	2015

Geothermal units

Name	Unit	Capacity MW	WASP retirement	Year of retirement
Los Azufres	U3	5		2012
Los Azufres	U4	5		2012
Los Azufres	U5	5		2012
Los Azufres	U6	5		2012

Hydro units (Type A)

Name	Unit	Capacity MW	WASP retirement	Year of retirement
Tingambato	U1	45		1998
Tingambato	U2	45		1998
Tingambato	U3	45		1998
El Durazno	U1	10		1998
El Durazno	U2	10		1998
Ixtapantongo	U1	27		1998
Ixtapantongo	U2	27		1998
Ixtapantongo	U3	50		1998
Santa Barbara	U1	25		1998
Santa Barbara	U2	25		1998
Santa Barbara	U3	25		1998

In order to perform expansion studies, which consider diverse technologies, nuclear and dual plants were considered also as expansion candidates in VARSYS. Table 4.17 shows the characteristics of the thermal generating plants considered as expansion alternatives. For the future hydro plants, CFE has performed studies for several projects. Special priority is given to the projects shown in Table 4.18. Due to their high investment costs, these projects will not be included in the expansion if they were offered in a free way. Nevertheless, due to the consideration that they are projects that bring additional benefits to the regions where the plants will be built, they are included as fixed in the CONGEN module in the years of commercial operation defined by CFE.

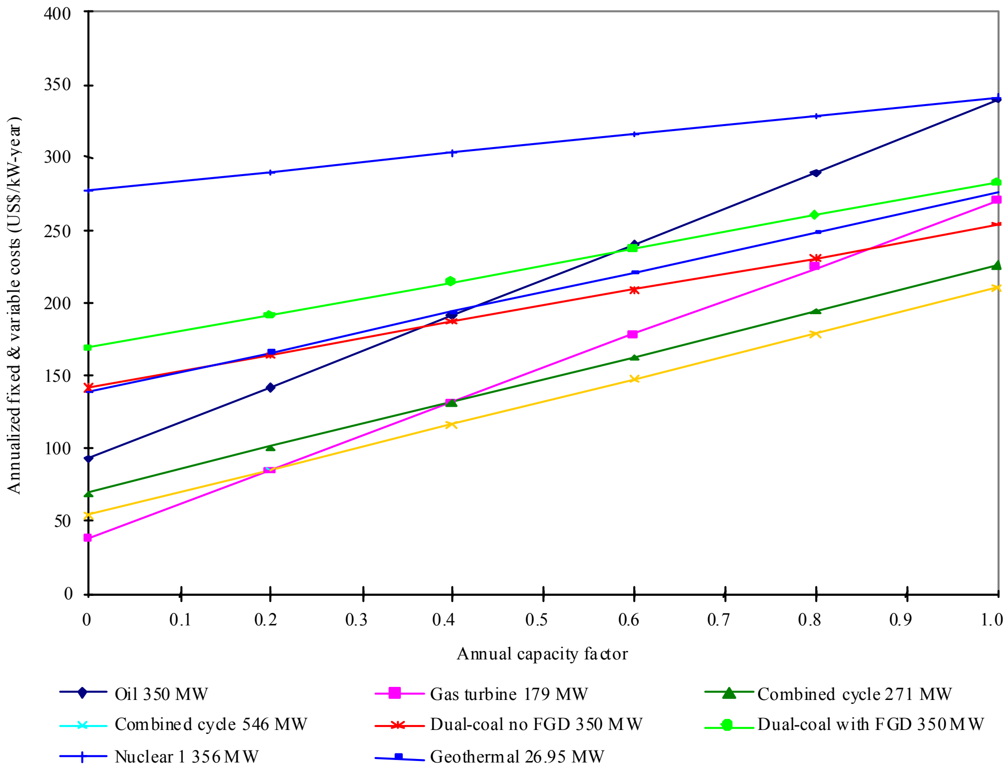

Figure 4.11. Generating system costs (US$ 1998).

4.16.1. Parameters for the simulation of the system operation

Tunnel width

In CONGEN, a type 1 INDEX = 2 card, followed by a type 2 card indicates the minimum number of projects of each VARSYS plant that can be contained in the configuration for a specific year. A type 1 INDEX = 3, followed by a type 3 card, specifies the maximum number of expansion projects permitted in addition to the minimum number required (given on the type 2 card). The type 3 card shows the so-called "tunnel width" for the year. This is usually a number between 0 and 2.

Minimum and maximum reserve margins

Reserve margin is a measure of the generating capacity available over and above the amount required to meet the system load requirements. It is the difference between the total available generating system capacity and the annual peak system load, divided by the peak system load. In order not to eliminate too many configurations in CONGEN that might conduct to a better solution, the minimum and maximum reserve margins were settled to 10% and 30%, respectively.

LOLP constraint

LOLP (LOss-of-Load Probability) is a reliability index that indicates the probability that some portion of the load will not be satisfied by the available generating capacity. It is the proportion of days per year or hours per year when insufficient generating capacity is available to serve all the daily or hourly loads. LOLP is usually expressed, as a ratio of times, for example, 2 days per year equals a probability of 0.005479 (2/365). According to CFE policies, a target LOLP level was set to 3 days per year; this means a probability of 0.8219%.

Table 4.17. Thermal power generating units considered as expansion alternatives

Interconnected System: Expansion Alternatives

Thermal power generating plants

1998 dollars

Name	Fuel	Net capacity		Net heat	Forced	Maintenance	Spinning	Fuel	Operation & maintenance cost (1)		Capital cost (1)
code (2)	type	Minimum	Maximum	rate	outage		reserve	cost	Fixed	Variable	
		MW	MW	kcal/kWh	%	days/year	%	US¢/10^6 kcal	US$/kW/month	US$/MWh	US$/kW
N1356	Nuclear	1 051	1 314	2 570.2	6.60	40	10	211	3.122	1.720	2 485.40
D350FGD	Coal	155	310	2 597.4	7.10	36	10	486	2.280	1.180	1 467.90
CC546	Natural gas	264	527	1 762.8	10.00	26	10	1 112	1.348	0.310	427.44
TG179	Natural gas	44	175	2 624.4	6.00	26	0	1 112	0.355	0.078	346.03

1) COPAR 1998

2) Gross Capacity (MW)

Table 4.18. Future hydro plants

Project name	Name code	Type	Capacity	Year of commercial operation
			MW	
San Rafael	RAFA	A	24	2002
Ampliación Chicoasén	ACHI	A	900	2003
El Cajón	CAJO	A	640	2006
Copainalá	COPA	B	210	2008
La Parota	PARO	B	765	2008

Energy not served cost

The energy not served is a reliability index that measures the expected amount of energy which will not be supplied per year owing to generating capacity deficiencies and/or shortages in basic energy supplies, expressed in units of kWh. The associated cost for the ENS was set by CFE to 1.5 US$/kWh.

Selection of the loading order

The loading order is calculated by MERSIM rearranging the basic economic L.O. of the thermal plants combined with FIXSYS and VARSYS. The MERSIM module will automatically dispatch base and peak blocks of the thermal plants in order to meet the spinning reserve (SPNRES) requirements of the system. SPNRES is given by the equation:

$$\text{SPNRES} = \text{SPNAL} \times \text{CAP} + \text{PEAK} \times \text{PKMW}$$

SPNAL	=	1 (instruction b of card type 2 for our case)
CAP	=	largest unit capacity block already loaded
PEAKF	=	multiplier of PKMW = 1 (for our case)
PKMW	=	period peak load

4.16.2. Use of emission abatement technologies

Since the power plants in Mexico are in compliance with the environmental law NOM-085-ECOL-1994 is not necessary to add abatement technologies in the existing plants. On the other hand, the alternatives for expansion include abatement technologies, specifically:

- Dual plant includes one electrostatic precipitator and one wet FGD scrubber (Chiyoda-CT121) with efficiencies of 99.5% for particulates and 90% for SO_2.

- The new combined cycle and the gas turbines have low NOX burners that guarantee NOX emissions lower than 110 *ppm* (0.281 kg NOX/106 kcal).

4.17. System-level analysis of generation system expansion

4.18. Base case analysis

4.18.1. Approach to reach the optimal solution

The process of generation planning for the Interconnected System shows that, in order to satisfy the growing electricity demand (5.5% growth rate), it is necessary to select the best technologies for the generation system expansion with a suitable level of reliability and minimum cost. Longer construction periods, cost and availability of fuels and expensive pollution control equipment must also be taken into consideration when a planner is deciding the number, type, and size of the generating units to be installed.

DECPAC module (WASP-III Plus version) of DECADES has been used to carry out the analysis of the base case and several different alternative plans for the future expansion of the power system over 27 years; the planning period is from 1998 to 2024. For the present study, Table 4.4 shows the thermal plant candidates that have been considered for future electric system expansion.

The combined cycle technology is very competitive because it uses a clean fuel (natural gas) and also has low investment costs, short construction periods and high thermal efficiency with respect to other technologies. As a result of these characteristics, it is the most attractive and competitive technology for the generation system expansion as it was already discussed and shown in Section 4.5 (Figures 4.2, 4.3 and 4.4) and Section 4.8 (Figure 4.11) by screening curves analyses.

It is important to indicate that there is no limitation on the natural gas supply in the base case and therefore the program can install the number of new units that the system needs in every year over the study period.

Another thermal technology that is considered as candidate for expansion is the gas turbine (179 MW). It uses natural gas or diesel fuel in alternative mode so that the fuel can be switched in an automatic way in every moment. The advantage of these units is their very short starting times so they are able to satisfy loads in the peak hours. Gas turbines of advanced technology are also considered. They can work in the base load and on the industrial co-generation.

In addition, a dual power plant (350 MW) with FGD system included and dual burners are considered. This plant burns coal and fuel oil in the alternative mode.

The last thermal candidate is the nuclear power plant (1,356 MW), which is an advanced boiling water reactor that usually is called ABWR and consumes imported enriched uranium.

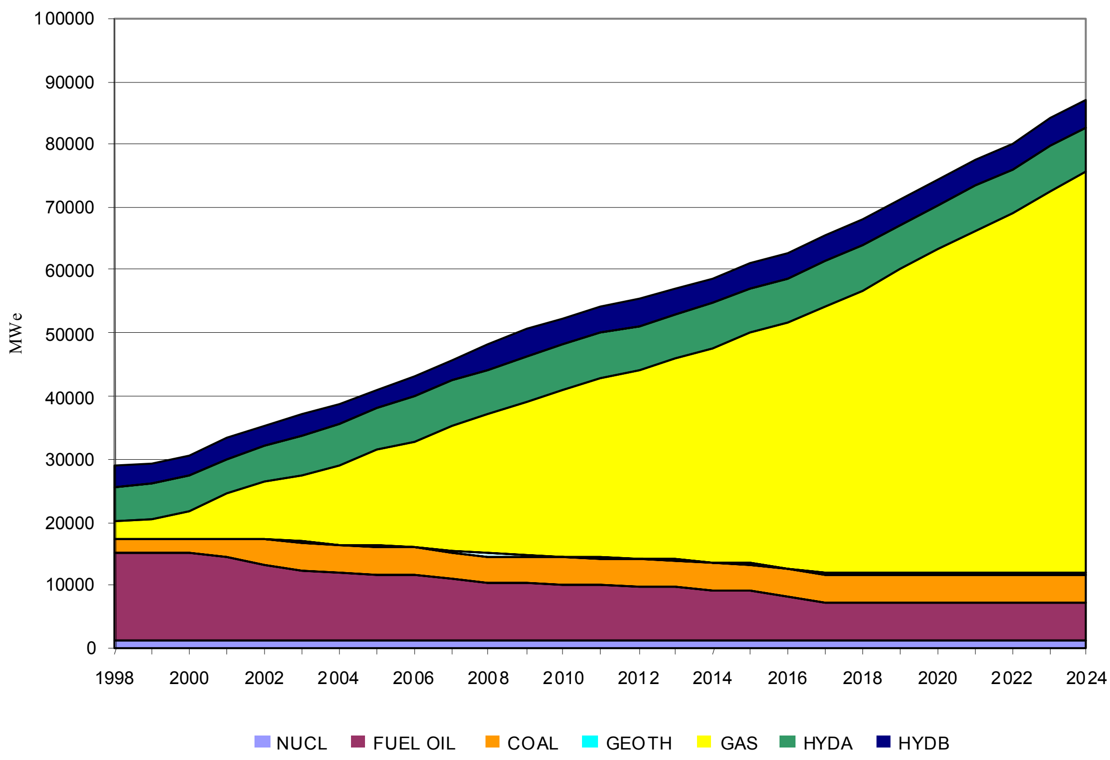

Figure 4.12. Total capacity for the interconnected system.

On the other hand, there is a large list of hydroelectric projects (31) as candidates (Table 4.9). The projects have specific characteristics because each site has different topographical and geological conditions. As a result there is a large variety of sizes, designs and construction methods. Some of the projects considered to be installed in the medium term (Table 4.18) are El Cajón (640 MW), La Parota (765 MW) and Copainalá (210 MW).

Some of the economic parameters to be considered in the present case were discussed in Section 3.7.3 and are crucial in the selection of future power plants. The base year is 1998 and it is assumed that the analysis is done in US dollars 1998 constant prices

4.18.2. Analysis of the structure of the power system

In the base case study the system develops on natural gas mainly through combined-cycle units and some gas turbines. Rapid unlimited expansion of natural gas increases the total capacity of the Interconnected System three-fold (29 GWe, to 87 GWe) and the capacity of gas-fired plants grows 26 times (2.5 GWe to 65 GWe) until 2024.

The total additional capacity is 68.8 GWe; the new units are: 118 combined cycle of 546 MWe (4-7 new units are set into operation annually), 6 gas turbines of 179 MWe and 2539 MWe of committed hydro projects: San Rafael (24 MWe), Ampliación Chicoasén (900 MWe), El Cajón (640 MWe), Copainalá (210 MWe) and La Parota (765 MWe).

The total capacity for the Interconnected System is shown in Figure 4.12 and the new capacities required by the system are given in Figure 4.13. Even that in the Figure 4.12 it appears the geothermal capacity, one must remember that for the expansion the geothermal units were added to the fixed thermal system as two 50 MW units. Also, as was mentioned, this consideration allows us to not create an additional category in VARSYS.

4.18.3. Analysis of the power system costs

Thermal power plants cost-data

As mentioned in Section 3.4.3, the investment cost of the expansion candidates is very important in order to select the best technologies in the formulation of the least-cost expansion plan.

Fuel prices and future escalations

The suitable selection of future projects should consider the monetary flow in each technology, from the construction period until the power plant is retired. During the operation period, the most important flow component is the cost of the fuel.

Discount rate

The discount rate plays a crucial role in the selection of future power plants for formulating power capacity expansion plans through economic optimization. The choice of an appropriate value for discount rate is the most complex issue in power expansion planning.

The real discount rate may be taken as equal to the opportunity cost of money in real terms in an economy or equal to the real cost of borrowing the investment funds. The real discount rate used in developed countries varies from 8% to 12%. The discount rate used in the present study for all types of costs is assumed to be 10%

Cost of energy not served

The expected energy not served (ENS) is the probabilistically determined amount of electrical demand per year that is not supplied owing to generating capacity deficiencies and/or shortages in basic energy supplies, such as hydroelectric energy. The ENS is calculated in

DECPAC through the probabilistic simulation process, which accounts for all the combination of random forced outages of generating units experienced by the generating system. ENS is used in the objective function just as an operating cost. Therefore, it is very important to select a proper value of ENS cost. In the present study, the ENS cost has been assumed as 1.5US$/kWh.

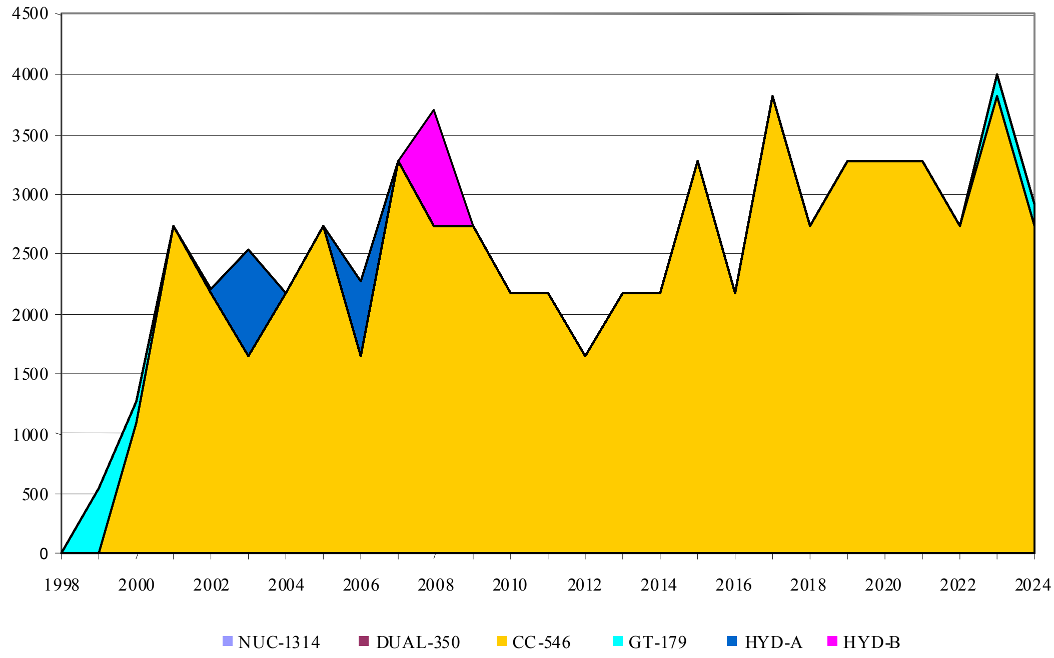

Figure 4.13. New capacities (MW) for the Interconnected System.

Investment requirements

Table 4.19 gives in constant prices the investments, the system operation costs (O&M and fuel costs) and the total annual costs in million of US dollars over the study period. Annual system costs grow proportionally to the increase in the total system capacity, mostly due to increasing of the fuel costs. The system in this condition becomes vulnerable to the possibility of gas price increases.

4.18.4. Formulation of the base case findings

The base case considers no supply limitation on fuels, no limit on annual inputs of new units and a reserve margin between 10 and 30% among other assumptions. This is the reference case. The formulation of the least cost base case had been performed in order to compare different alternative expansion plans.

The present analysis of the power generation capacity expansion has shown that the system develops on natural gas; a number of 4 to7 new combined cycle units are put into operation annually. The optimal solution until 2024 shows that as a result of the expansion, the system will be requiring 118 combined cycle units of 546 MW, 6 gas turbines units of 179 MW and 5 hydroelectric projects (2,539 MW). This means a total of 65,502 MW based on natural gas.

Table 4.19. Annual costs

Year	Investments million US$	Operation cost million US$	Total million US$
1998	25.43	3 316.10	3 368.53
1999	262.05	3 909.10	4 171.15
2000	651.44	4 101.20	4 752.64
2001	994.79	3 788.00	4 782.79
2002	848.33	3 795.50	4 643.83
2003	886.70	3 941.00	4 827.70
2004	1 000.98	4 123.40	5 124.38
2005	1 524.47	4 300.40	5 824.87
2006	2 012.90	4 523.30	6 536.20
2007	1 362.86	4 730.10	6 092.95
2008	650.18	4 941.20	5 591.38
2009	828.24	5 210.20	6 038.44
2010	828.24	5 485.20	6 313.44
2011	828.24	5 771.80	6 600.04
2012	893.25	6 074.20	6 975.45
2013	1 035.30	6 366.70	7 402.00
2014	1 100.31	6 675.40	7 775.71
2015	1 177.35	6 975.00	8 152.35
2016	1 100.31	7 314.00	8 414.31
2017	1 242.36	7 648.70	8 891.06
2018	1 177.35	8 012.20	9 189.55
2019	1 100.31	8 398.10	9 498.41
2020	1 242.36	8 788.10	10 030.46
2021	1 242.36	9 193.50	10 435.86
2022	1 259.83	9 612.40	10 872.23
2023	1 298.02	10 045.80	11 343.82
2024	890.49	10 492.50	11 382.99

The heavy dependence on natural gas could be a serious problem in the long term due to uncertainty in several factors:

- In spite of the existing gas reserves in Mexico, there is an uncertainty on the domestic natural gas production in the long term, as well as on the infrastructure required to handle the gas;
- The growing national demand of natural gas in the different sectors;
- The demand growth is bigger than the supply and as a consequence there is a mayor dependence on gas imports, the uncertainly in gas imports is very high in the long term;
- The variability of international gas prices; and,
- The high demand of gas-fired technologies in the international market could be a limitation in the near future, because the new units will be imported.

It is important to mention that the 5 hydroelectric projects included in the expansion plan are committed plants. This means that no other hydro project is considered due to a very high investment costs.

On the other hand, the analysis of costs shows that the cumulative investments in present worth for capacity additions reached US$ 9,548 million and the cumulative system operation costs US$ 44,871 million (O&M and fuel costs) over the planning period. As a result, the total cost has been estimated in US$ 54,419 million.

In addition the annual system costs grow proportionally to the increase in the total system capacity, mostly due the increasing fuel costs. In these circumstances the system would be very vulnerable to the possibility of gas price increases.

During the operation of the power system it is assumed a reserve margin between 10 and 30%, the results showed that the system has a reserve around 33% in the first 10 years (medium term) and then it decreases up to 23% during the next 9 years and it reaches 18% in the last years of the period.

Another operation results are the reliability of the power system. In this case the LOLP in the medium term is very small, it is around 0.06 days/year; the LOLP reaches a value of 2.72 day/year during the last 6 years of the planning period, which is an acceptable value.

The analysis of the power system expansion has shown that the future electricity capacity is likely to be based on natural gas. Therefore, it is useful to perform an analysis with different alternative expansion plans in order to diversify the power system, considering all possible energy supply sources in the country and in this way obtain a robust expansion plan.

4.19. Scenario structure and analysis of expansion alternatives

4.19.1. Structure of the scenario alternatives

In order to study the impact of several possible causes on the expansion of the power sector it was considered convenient to develop a set of alternatives for the expansion of the sector. In addition to the Base Case, 13 alternatives were developed taking into account the following aspects or possibilities:

(1) Higher demand growth (6.5% demand growth rate instead 5% demand growth rate);

(2) Nuclear options (low nuclear cost and forced introduction);

(3) Escalation of fossil fuels (slightly higher fossil prices, notably higher gas prices and increase of the gas price in the medium term);

(4) Limitation in the introduction of new gas fired units (annual introduction of CC units is limited to 3 units/year and annual gas supply is limited starting 2010 (the gas limitation equals the gas supply in 2010);

(5) Variation of the discount rate (8% and 12% instead 10%); and,

(6) Changes in the target reliability (the reserve margins and/or the cost of energy not served (ENS) are defined to obtain a LOLP of 1 day per year, 5 days per year and a decreased reserve margin (by a decrease in the ENS value) for the early years of the period (this reflects the possible policy direction with respect to the reserve margin).

Table 3.20 shows the final list of expansion alternatives plans of the Interconnected System for this study. Besides, the description of the specific alternative it includes, for the Interconnected System, the set of expansion candidates for each alternative.

(a) Alternative A_1: Impact of higher demand growth

Due to the uncertainty of the load growth, it was considered useful to analyze an alternative scenario for the demand; a higher demand growth rate of 6.5% instead of 5.5% considered in the Base Case.

(b) Analysis of the nuclear option

Two cases of sensitivity have been carried out for the nuclear option:

- **Alternative B_1:** Considers low nuclear costs in which the investment cost of new nuclear power plant is assumed to be 48% lower than in the Base Case investment cost allowing new nuclear power plants to appear in the optimal solution.

- **Alternative B_2:** Is a case of a forced nuclear introduction that includes one forced nuclear power plant of 1,356 MW in order to see the possible non-economic advantages of this additional nuclear power plant, for example lower emissions or a more diversified power system, and its impact on the system cost.

(c) Impact of the escalation of fossil fuel prices

With the purpose of analyze the effect on the escalation of fossil fuel prices in power expansion planning; three different cases have been performed:

- **Alternative C_1:** Case of slightly higher fossil fuel prices. This case includes a slightly higher alternative projection for the escalation of fossil fuel prices (natural gas and the others).

- **Alternative C_2:** Case of notably higher gas prices. Due to a recent increase of gas prices it has been assumed a higher projection for the prices of this fuel, 4 US$/tcf instead of 2.9 US$/tcf in the base case.

- **Alternative C3**: Case of a medium-term increase in the gas price. This case starts with a gas price of 2.9 US$/tcf as in the base case, next it considers a peak of 12 US$/tcf in 2010 and then a decline to 4 US$/tcf in 2024.

(d) Limitations on the introduction of new gas-fired units

In order to evaluate the impact of reducing the number of new gas fired units due to technical reasons or gas supply constrains, two sensitivity analyses have been carried out:

- **Alternative D1:** Case of limitation on the number of CC-546 units; in this case the annual inputs of new combined cycle units of 546 MW are limited to 3 units per year instead of 4 to7 units as in the Base Case. The limitation starts in 2010.

- **Alternative D2**: Case of limited gas supply; natural gas imports are not firmly established after 2010, for this reason it is assumed that the annual gas supply is limited starting in 2010, the limit equals the gas supply in 2010.

(e) Variation of the discount rate

Two cases with variation of the discount rate have been performed in order to see the impact on capital availability.

- **Alternative E1**: Case of increased discount rate; it is assumed a discount rate of 12% instead of 10% as in the Base Case, reflecting a higher cost of capital.
- **Alternative E2**: Case of decreased discount rate; it is assumed 8% instead 10% as in the Base Case, reflecting a lower cost of capital.

(f) Changes of the reliability

With the objective of analyzing different reliability criteria on the power system, three sensitivity analyses have been carried out.

- **Alternative F1**: Case of increased power system reliability; the cost of ENS is redefined to obtain a LOLP of one day per year (0.27%) instead of 3 days per year as in the Base Case.

- **Alternative F2**: Case of decreased power system reliability; in this case the cost of ENS is redefined to obtain a LOLP of 5 days per year (1.37%) instead of 3 days per year in the base case. The case will show the impact of the system becoming less reliable (e.g. as a result of deregulation)

- **Alternative F3**: Case of decreased reserve margin; the case is configured to obtain a lower reserve margin in the study by a decrease in the cost of ENS. This reflects the possible policy direction with respect to the reserve margin.

4.20. Analysis of the expansion alternatives

4.20.1. Impact of lower investment costs for new nuclear power plants

For Alternative B_1 it has been assumed that the investment cost of a new nuclear power plant is 1,292 US$/kW instead of 2,485 US$/kW as in the Base Case. In this condition new nuclear power plants are competitive with the rest of the candidate technologies for expansion. In order to analyze the impact of new nuclear power plants on the power system the Alternative B_1 has been considered.

Table 4.20. Final alternatives for the Interconnected System

Case ID	Alternative	N1356	D350	CC546	TG179	HYD-A	HYD-B	Comments
106	Base Case	0	0	118	6	3	2	**Features:** 5% growth rate, conservative nuclear cost, moderate price escalation for fossil fuels, no supply limit for natural gas, 10% discount rate, reliability (LOLP) 3 days/year, reserve margin changing from 30% to 10%, wet FGD on new coal units
A. Impact of higher demand growth								
65	A1	0	0	157	27	3	2	**High growth demand**: A higher demand growth than in the Base Case is assumed (6.5% instead of 5%)
B. Nuclear option								
63	B1	5	0	105	9	3	2	**Low nuclear costs**: The investment cost of new nuclear power plants is assumed to be 48% lower than in the base case, allowing 5 new nuclear power plants to appear in the optimal solution
74	B2	1	0	115	9	3	2	**Forced nuclear introduction**: Includes 1 forced nuclear power plant of 1 356 MWe with the objective to see possible non-economic advantages of an additional nuclear power plant (lower emissions, a more diversified power system) and its impact on the system cost
C. Escalation of fossil fuel prices								
71	C1	0	0	119	4	3	2	**Slightly higher fossil fuel prices**: includes an alternative projection for the escalation of fossil fuel prices (natural gas and others)
78	C2	0	0	110	30	3	2	**Notably higher gas prices**: includes a recent projection for the gas prices (around 4 US$/tcf instead of 2.9 US$/tcf as in the Base Case)
82	C3	0	159	26	4	3	2	**Medium-term increase in the gas price**: assumes the peak of 12 US$/tcf in 2010 (from 2.9 in 1998) and then a decline to 4 US$/tcf in 2024
D. Limitations in the introduction of new gas fired units								
68	D1	0	57	85	4	3	2	**Limitation on the number of CC-546 units**: Annual inputs of CC units on natural gas are limited to 3 units/year (instead of 4 to 7 units as in the base case)
70	D2	0	122	45	4	3	2	**Limited gas supply**: The annual gas supply is limited starting 2010; the limit equals the gas supply in 2010
E. Variation in the discount rate								
58	E1	0	0	118	5	3	2	**Increased discount rate**: 12% discount rate instead of 10% discount rate as in the Base Case (reflecting a higher cost of capital)
31	E2	0	0	118	8	3	2	**Decreased discount rate**: 8% discount rate instead of 10% discount rate as in the Base Case (reflecting a lower cost of capital)
F. Changes in the target reliability								
73	F1	0	0	119	15	3	2	**Increased power system reliability**: The reserve margins and/or the cost of ENS are defined to obtain the LOLP of 1 day per year (instead of 3 as in the Base Case)
66	F2	0	0	116	4	3	2	**Decreased power system reliability**: The reserve margins and/or the cost of ENS are defined to obtain the LOLP of 5 days/year. The case would show the impact of a system becoming less reliable (e.g. as a result of deregulation)
77	F3	0	0	113	4	3	2	**Decreased reserve margin in early years**: The case is configured to obtain a lower reserve margin in the study (by a decrease in the cost of ENS). This reflects the possible policy direction with respect to the reserve margin

It may be noted that in this case five new nuclear power plants of 1,356 MW appeared, with 13 combined cycle plants less than in the Base Case and three additional gas turbine plants than in the Base Case. The coal, hydroelectric and geothermal capacities are the same as those in the Base Case. With the new nuclear capacity of 6,780 MW the share of nuclear power capacity it will be increased from 1.5% in the Base Case to 9% while the share of gas based capacity will decrease from 73% in the Base Case to 66% in this alternative plan. The future installed capacity for Alternative B_1 is shown in Figure 3.14.

On the other hand, the comparison of costs in present value for the Base Case and the Alternative B_1 shows that, because the investment cost for new nuclear power plants is 48% lower than in the Base Case, the total cumulative costs are very similar. Table 4.21 shows the cumulative investment and operation costs for these cases. Compared to the Base Case the cumulative investment cost is US$ 837 million higher and the cumulative operation cost is US$ 313 million lower.

This alternative plan has been evaluated with the objective to look at possible non-economic advantages of additional nuclear power plants. The advantages would be lower emissions and a more diversified power system.

Table 4.22 shows, for the Base Case, Alternative B_1 and the years 1998, 2010 and 2024, the annual environmental emissions from power generation. For the Base Case, it may be noted that the annual emissions of CO_2 and NO_X will increase, over the study period, by 138.5% and 53%, respectively, while the emissions of SO_X and particulate will decrease by 78% and 83%, respectively.

On the other hand, the annual emissions of CO_2 and NO_X in Alternative B_1 will increase by 116% and 42%, respectively, over the study period, while the emissions of SO_X and particulate will decrease by 76% and 82%, respectively, over the same period. For a detailed discussion of the results of Alternative B_2 see Appendix VII.

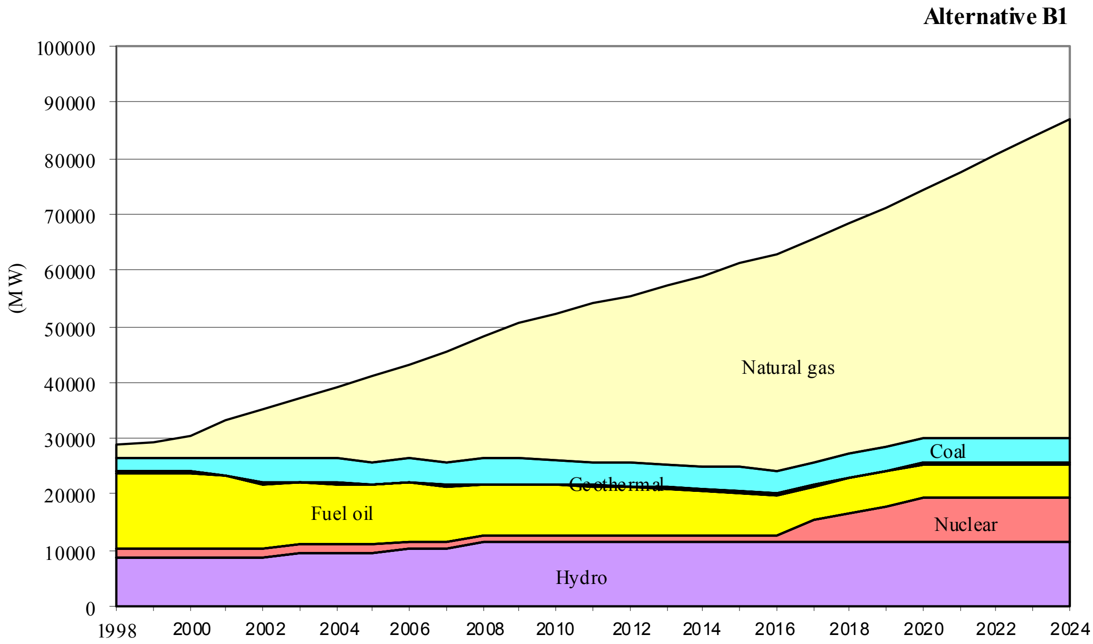

Figure 4.14 Projected installed capacity (Alternative B_1).

For Alternative B_1, in the year 2024, the SO_X and particulate emissions are higher than in the Base Case, however, for the same year, the emissions of CO_2 and NO_X, are lower than in the Base Case.

Table 4.21 Cumulative investment and operation costs

Alternative	Investment	Operation	Total
	million US$ (1998)	million US$ (1998)	million US$ (1998)
Base Case	9 548	44 871	54 419
Alternative B1	10 385	44 558	54 943

4.20.2. Impact of a escalation of natural gas prices

In view of the present energy policy of high penetration of natural gas in all energy and economic activities, it was considered useful to analyze alternative plans for the expansion of the power sector by taking different future projections of the natural gas prices with the purpose of evaluating their impacts on the electricity generation system.

The following three alternative expansion plans were analyzed, looking at their investment and fuel costs, capacity expansion and environmental impacts:

- **Alternative C_1:** Case of slightly higher fossil fuel prices
- **Alternative C_2:** Case of notably higher gas prices
- **Alternative C_3:** Case of a medium term increase in the gas price

Table 4.22 Annual environmental emissions from the power generation

	1998		2010		2024	
	Base Case	Alternative B1	Base Case	Alternative B1	Base Case	Alternative B1
	million ton	million ton	million ton	million ton	million ton	million ton
UCO_2	81 892.78	81 892.78	109 266.80	109 266.80	195 519.76	177 025.81
	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton
CSOx	1 537.94	1 537.94	533.78	533.78	344.00	356.58
USOx	1 537.94	1 537.94	533.78	533.78	344.00	356.58
	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton
CNOx	221.31	221.31	242.27	242.27	338.01	315.16
UNOx	221.31	221.31	242.27	242.27	338.01	315.16
	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton
CParticulate	93.88	93.88	27.58	27.58	16.27	17.02
UParticulate	93.88	93.88	27.58	27.58	16.27	17.02

The Alternative C_1 includes an alternative projection for the escalation of fuel oil, coal, uranium and natural gas. The initial fuel prices in this case are the same as those in the Base

Case except for the gas price which is 2.96 US$/tcf instead of 2.88 US$/tcf. The future escalation for the fuel prices is given in Table 4.23.

Table 4.23 Escalation of fuel prices

Year	Nuclear	Fuel oil	Coal	Geothermal	Gas
2000	1.0149	1.1461	0.9839	1.0000	0.9392
2005	1.0545	1.2566	0.9753	1.0000	0.9545
2010	1.0941	1.3648	0.9624	1.0000	1.0203
2015	1.1337	1.4445	0.9599	1.0000	1.0946
2020	1.1782	1.4579	0.9599	1.0000	1.1892
2024	1.2129	1.4685	0.9599	1.0000	1.2635

This case considers the same assumptions on the supply side as those for the Base Case except for the difference in the scenario of fuel prices. In this alternative the additional capacity is almost the same as that in the Base Case. This case assumes the construction of one additional combined cycle unit and two gas turbines less by 2024 than in the Base Case. The share of electricity generation is practically the same as in the Base Case. The projected installed capacity is shown in Figure 4.15.

Alternative C_2, assumes that the gas price is 4.02 US$/tcf in the base year instead of 2.88 US$/tcf as in the Base Case. Practically, the natural gas price remains around 4 US$/tcf over the planning period. The remaining assumptions are the same as in the Base Case.

The escalation for gas prices in this alternative is shown in Table 4.24. It may be noted that the gas fired capacity is about 65,430 MW (110 combined-cycle units and 30 gas turbine units) which is essentially identical, in terms of total capacity, as that in the Base Case. The unique differences in this alternative expansion plan are eight combined cycle 546 MW units less and 24 GT-179 MW units more than in the Base Case. The share of gas fired capacity and the other capacities are the same as those in the Base Case. The projected installed capacity is shown in Figure 4.16.

One of the major uncertainties to be considered in the power system expansion planning is the future evolution of fuel prices. For this reason Alternative C_3 assumes that the gas price is increased from 2.88 US$/tcf in 1998 up to a peak of 12 US$/tcf in 2010 and then it declines to 4 US$/tcf in 2024.

Figure 4.17 shows the escalation of the gas price for this alternative plan. Due to this higher price scenario for gas it may be noted that the additional coal fired capacity is incremented to 55,650 MW as compared to no coal capacity in the Base Case, whereas the additional gas fired capacity is only 14,912 MW as compared to about 65,500 MW in the Base Case. This alternative assumes that 159 dual units of 350 MW based on coal, 26 combined cycle units of 546 MW and four gas turbines units of 179 MW will be constructed, whereas hydroelectric capacity remains the same as in the Base Case.

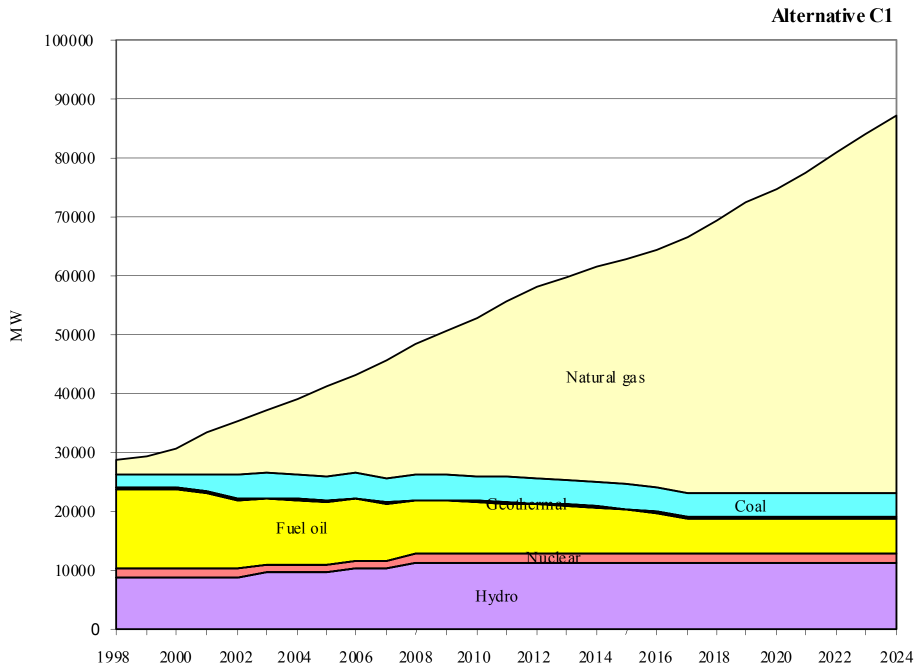

Figure4.15 Projected installed capacity (Alternative C_1).

Table 4.24 Scenario of natural gas prices

Year	Price	Escalation
	US$/tcf	
1998	4.02	1.0000
2000	4.02	1.0000
2005	3.88	0.9640
2010	3.70	0.9209
2015	3.70	0.9209
2020	3.83	0.9520
2024	3.92	0.9760

Figure 4.18 shows the future installed capacity for this case. The impact of the gas price and its future projection is high because the share of gas fired capacity has significantly decreased from 73% in the Base Case to 17%, while the share of coal fired capacity grew from 0% in the Base Case to 61% in this alternative. Due to the efficiency of dual plants about 5 060 MW of additional capacity is required in the optimal solution compared with that in the Base Case.

The comparison in present value of the investment requirements for power generation of the Base Case and Alternatives C_1, C_2 and C_3 is given in Table 4.25.

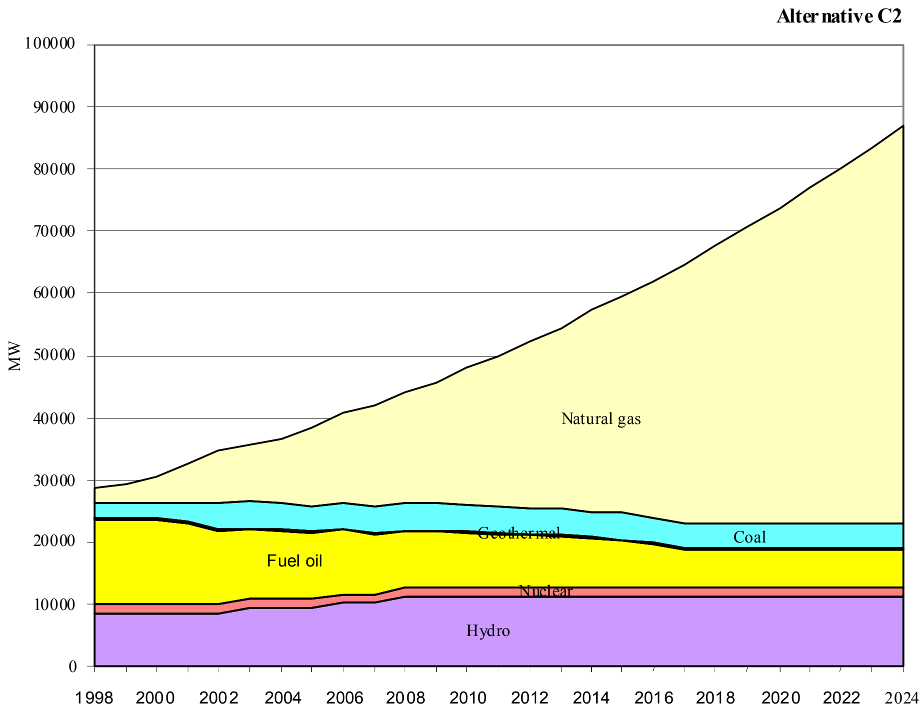

Figure 4.16 Projected installed capacity (Alternative C_2).

Compared to the Base Case, the cumulative investment cost in Alternative C_1 is US$ 150 million higher and the operation cost is US$ 4,244 million higher. The total cost for Alternative C_1 is US$ 58,813 million, which is 8% more than the total cost for the Base Case.

In the case of Alternative C_2 the cumulative investment cost decrease a little bit due to the lower capital costs for gas turbines compared to those for combined cycle units. The cumulative investment cost in this alternative is 7% lower than in the Base Case. It may be noted that compared to the Base Case the cumulative operation cost is 21% higher. This represents an increment of 16% in the total cost with respect to the Base Case mainly because of the fuel costs.

In this sensitivity analysis Alternative C_3 assumes a higher scenario for gas prices and for this reason the optimal solution is totally different with respect to new capacities and investment requirements. The cumulative investment costs grew from US$ 9,548 million in the Base Case up to US$ 27,692 million in this alternative. Compared to the Base Case the cumulative total cost for Alternative C_3 is 46% higher which represents extra requirements of US$ 25,195 million.

Table 4.26 gives, for the Base Case and the Alternatives C_1, C_2 and C_3, the annual environmental emissions from power generation in the years 1998, 2010 and 2024. It may be noted that the annual emissions of CO_2 and NO_X in Base the Case will increase by 138% and 53%, respectively, over the study period, while the emissions of SO_X and particulate will decrease by 78% and 83%, respectively, over the same period.

For Alternative C_1, the annual emissions of CO_2 and NO_X will increase by 138% and 52%, respectively, over the study period, while the emissions of SO_X and particulate will decrease by 78% and 84%, respectively, over the same period.

Table 4.25. Comparison in present value of the investment requirements for power generation

Year	Gas price US$/1000 cf	Escalation rate fraction
1998	2.88	
1999	3.64	1.2639
2000	4.40	1.5278
2001	5.16	1.7917
2202	5.92	2.0556
2003	6.68	2.3194
2004	7.44	2.5833
2005	8.20	2.8472
2006	8.96	3.1111
2007	9.72	3.3750
3008	10.48	3.6389
2009	11.24	3.9028
2010	12.00	4.1667
2011	11.40	3.9583
2012	10.80	3.7500
2013	10.20	3.5417
2014	9.60	3.3333
2015	9.00	3.1250
2016	8.40	2.9167
2017	7.80	2.7083
2018	7.20	2.5000
2019	6.60	2.2917
2020	6.00	2.0833
2021	5.50	1.9097
2022	5.00	1.7361
2023	4.50	1.5625
2024	4.00	1.3889

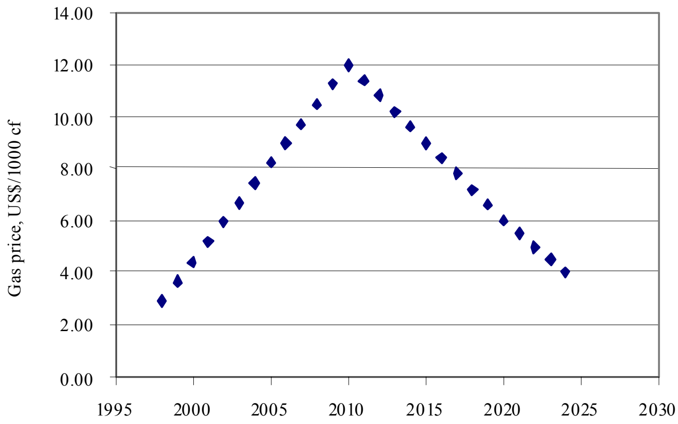

Figure 4.17 Scenario of gas prices.

For Alternative C_2, the annual emissions of CO_2 and NO_X will increase by 143% and 68%, respectively, over the study period, while the emissions of SO_X and particulate will decrease by 51% and 55%, respectively, over the same period. Finally, for Alternative C_3, the annual emissions of CO_2 and NO_X will increase by 293.6% and 81.44%, respectively, over the study period, while the emissions of SO_X and particulate will decrease by 59.04% and 37.94%, respectively, over the same period.

4.20.3. Impact of a natural gas supply limitation

In view of various uncertainties about future evolution of gas supply in Mexico, it was considered convenient and necessary to explore alternative plans for the expansion of the electricity generation system considering gas supply limitations. With this purpose, in addition to the base case, the following two alternative expansion plans have been carried out:

- **Alternative D_1:** Case of limitation on the number of combined cycle units
- **Alternative D_2:** Case of limited gas supply

Table 4.26 Cumulative investment and operation costs

Alternative	Investment	Operation	Total
	million US$ (1998)	million US$ (1998)	million US$ (1998)
Base Case	9 548	44 871	54 419
Alternative C_1	9 698	49 115	58 813
Alternative C_2	8 894	54 258	63 152
Alternative C_3	27 692	51 922	79 614

In Alternative D_1, starting year 2009, the annual inputs of new combined-cycle of 545 MW are limited to 3 units per year instead of 4 to 7 units in the Base Case. The Base Case assumes the construction of about 65,500 MW based on natural gas by the year 2024 whereas the Alternative D_1 assumes that 19,950 MW based on coal will be constructed (57 Dual units) and

47,126 MW based on gas (85 combined cycle units and 4 gas turbine units). The building up programs for hydro capacity, nuclear power capacity and geothermal capacity in this alternative are essentially identical to those in the Base Case.

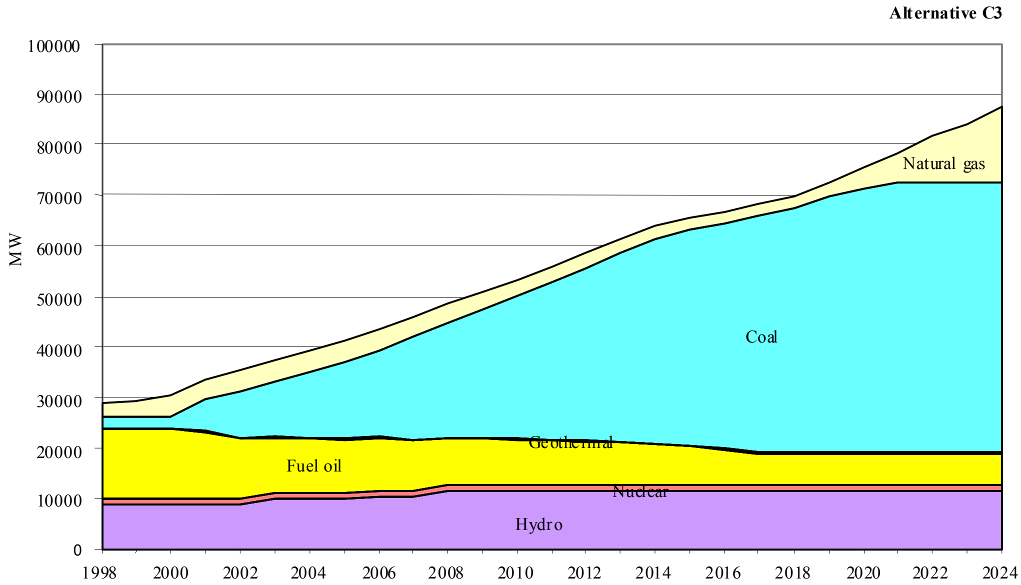

Figure 4.18 Projected installed capacity (Alternative C_3).

The future electricity generation for Alternative D_1 is shown in Figure 4.19. It may be noted that in this case the share of electricity generation based on coal is 25% in the terminal year compared to zero percent in the Base Case, whereas the share of gas fired capacity has decreased from 73% in the Base Case to 53% in this alternative. It is important to mention that alternative D_1 requires maintaining the same level of reserve and reliability as in the Base Case. This is due to the efficiency of dual power plants, which is lower than in combined cycle plants.

In Alternative D_2, it has been assumed that due to natural gas imports are not firmly established by this year. The gas supply is only for gas-fired plants installed up to 2010, and then there are limitations on the installation of new gas fired plants. In these conditions the gas-fired additions in the Base Case have been replaced by coal fired plants. The results show that will be constructed and the capacity additions based on natural gas remain in 24,570 MW from 2010 up to 2024.

The projected installed capacity for alternative D_2 for the future years is given in Figure 3.20. It may be noted that the hydroelectric capacity grows 770 MW by 2021 due to the installation of three hydroelectric projects (Atexcaco 120 MW, San Juan Tetelcingo 610 MW and Nuevo Tuxpango of 40 MW). Nuclear and geothermal capacities remain the same as in the Base Case. The share of electricity generation based on natural gas has significantly decreased in this case up to 29% instead of 93% as in the Base Case, the share of electricity generation based on coal plants grew from zero percent in the Base Case to 40% while the share of hydroelectric capacity has increased from 13% to 14% in this alternative expansion plan.

Table 4.27 shows the investment requirements over the whole planning period for the Base Case and Alternatives D_1 and D_2. The cumulative investments and cumulative system

Table 43.27 Annual environmental emissions from power generation

	1998			
	Base Case	**Alternative C_1**	**Alternative C_2**	**Alternative C_3**
	million ton	million ton	million ton	million ton
UCO_2	81 892.78	81 892.78	84 368.19	81 892.78
	thousand ton	thousand ton	thousand ton	thousand ton
CSOx	1 537.94	1 537.94	1 708.69	1 537.94
USOx	1 537.94	1 537.94	1 708.69	1 537.94
	thousand ton	thousand ton	thousand ton	thousand ton
CNOx	221.31	221.31	213.89	221.31
UNOx	221.31	221.31	213.89	221.31
	thousand ton	thousand ton	thousand ton	thousand ton
CParticulate	93.88	93.88	104.19	93.88
UParticulate	93.88	93.88	104.19	93.88
	2010			
	Base Case	**Alternative C_1**	**Alternative C_2**	**Alternative C_3**
	million ton	million ton	million ton	million ton
UCO_2	109 266.80	108 375.18	122 804.34	169 898.19
	thousand ton	thousand ton	thousand ton	thousand ton
CSOx	533.78	496.38	1 215.79	601.59
USOx	533.78	496.38	1 215.79	601.59
	thousand ton	thousand ton	thousand ton	thousand ton
CNOx	242.27	238.23	266.55	654.10
UNOx	242.27	238.23	266.55	654.10
	thousand ton	thousand ton	thousand ton	thousand ton
CParticulate	27.58	25.32	68.82	43.80
UParticulate	27.58	25.32	68.82	43.80
	2024			
	Base Case	**Alternative C_1**	**Alternative C_2**	**Alternative C_3**
	million ton	million ton	million ton	million ton
UCO_2	195 519.76	195 140.30	205 326.89	322 597.00
	thousand ton	thousand ton	thousand ton	thousand ton
CSOx	344.00	326.41	845.04	630.00
USOx	344.00	326.41	845.04	630.00
	thousand ton	thousand ton	thousand ton	thousand ton
CNOx	338.01	336.48	361.12	1 192.42
UNOx	338.01	336.48	361.12	1 192.42
	thousand ton	thousand ton	thousand ton	thousand ton
CParticulate	16.27	15.21	46.44	58.26
UParticulate	16.27	15.21	46.44	58.26

operation costs (O&M and fuel costs) in present worth are shown for the three alternative expansion plans. In the Base Case, the cumulative investments for capacity additions have been estimated in US$ 9,548 million and the cumulative system operation costs in US$ 44,871 million.

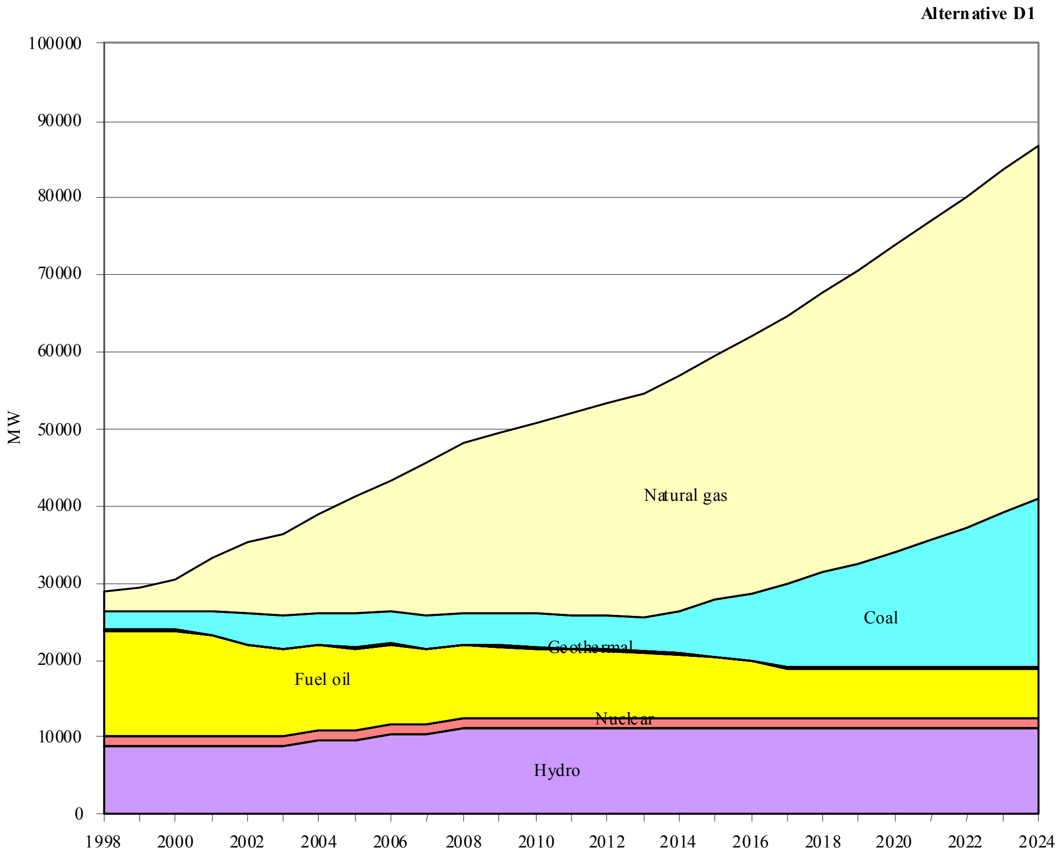

Figure 4.19 Projected installed capacity (Alternative D_1).

Compared to the Base Case, the cumulative investments in Alternatives D_1 and D_2 are US$ 2,409 million and US$ 5,939 million higher, respectively; this is due to the fact that capital costs of dual power plants are higher compared to those for combined cycle technology. On the other hand, the system operation costs in Alternative D_1 and D_2 are lower compared to those in the Base Case. This difference is due to the low fuel costs of the coal power plants.

The Table 4.28 shows, for the Base Case and Alternatives D_1 and D_2, the annual environmental emissions from power generation for the years 1998, 2010 and 2024. It may be noted that the annual emissions of CO_2 and NO_X in the Base Case will increase by 138% and 53%, respectively, over the study period, while the emissions of SO_X and particulate will decrease by 78% and 83%, respectively, over the same period.

For Alternative D_1, the annual emissions of CO_2 and NO_X will increase by 194% and 192%, respectively, over the study period, while the emissions of SO_X and particulate will decrease by 72% and 67%, respectively, over the same period.

Finally, for Alternative D_2, the annual emissions of CO_2 and NO_X will increase by 258% and 351%, respectively, over the study period, while the emissions of SO_X and particulate will decrease by 62% and 47%, respectively, over the same period.

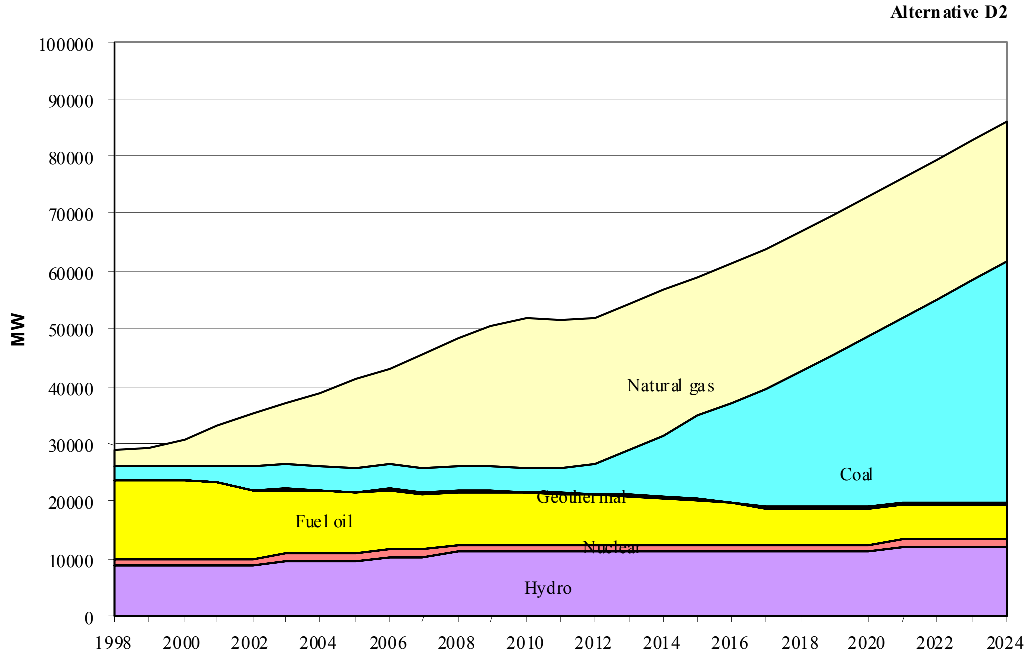

Figure 4.20 Projected installed capacity (Alternative D_2).

4.20.4. Impact of a variation of the discount rate

In this case, the runs were done with two additional values for the discount rate, 12% and 8%, instead the 10% of the Base Case. From the general point of view, for a discount rate of 12% the capital cost is higher than the capital cost for the Base Case and a value of 8% for the discount rate will reflect a lower capital cost, also with respect to the Base Case. As we can see from Table 4.20, the other difference lies in the number of gas turbine units, five for Alternative E_1 and eight for Alternative E_2.

For a value of 12% for the discount rate, Alternative E_1, the results reflect lower capital availability. Higher discount rates reduce the effect of the benefits that are far away in time and hence penalize plants with higher initial capital costs but with lower or no fuelling costs, *e.g.* hydroelectric and nuclear plants. The choice of an appropriate value for discount rate is the most complex issue in power system expansion planning. It may be noted in this alternative the final capacity is almost the same as in the Base Case.

Table 4.28 Cumulative investment and operation costs

Alternative	Investment	Operation	Total
	million US$ (1998)	million US$ (1998)	million US$ (1998)
Base Case	9 548	44 871	54 419
Alternative D_1	11 957	44 544	56 501
Alternative D_2	15 487	43 761	59 248

The solution for Alternative E_1 is different to the solution for the Base Case, in the sense that it is required one less gas turbine of 179 MW for this alternative. The system will require 118 combined cycle units of 546 MW (the same number as in the Base Case), five gas turbine units of 179 MW (one less than in the Base Case) and five hydroelectric projects (the same number as in the Base Case). For the Alternative E_2, the difference lies in the number of gas turbine units, eight in Alternative E_2 instead of six as in the Base Case.

Table 4.29 Annual environmental emissions from power generation

	1998			2010			2024		
	Base Case	**Alternative D_1**	**Alternative D_2**	**Base Case**	**Alternative D_1**	**Alternative D_2**	**Base Case**	**Alternative D_1**	**Alternative D_2**
	million ton	million ton	million ton	million ton	million ton	million ton	million ton	million ton	million ton
UCO_2	81 892.78	81 892.78	81 892.78	109 266.80	112 976.68	110 350.06	195 519.76	241 286.61	293 370.14
	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton
CSOx	1 537.94	1 537.94	1 537.94	533.78	704.90	580.90	344.00	444.32	590.39
USOx	1 537.94	1 537.94	1 537.94	533.78	704.90	580.90	344.00	444.32	590.39
	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton
CNOx	221.31	221.31	221.31	242.27	253.52	246.34	338.01	646.08	998.76
UNOx	221.31	221.31	221.31	242.27	253.52	246.34	338.01	646.08	998.76
	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton
CParticulate	93.88	93.88	93.88	27.58	37.91	30.42	16.27	31.25	50.22
UParticulate	93.88	93.88	93.88	27.58	37.91	30.42	16.27	31.25	50.22

On the other hand, due to higher discount rate the cumulative investment and operation costs are very different compared to the ones in the Base Case. Table 4.30 shows the cumulative and operation costs, for Alternative E_1, compared with the Reference Case. It may be noted that the cumulative investment cost is 16% lower and the cumulative operation cost is 16.5% lower than in the Base Case.

Table 4.30 Cumulative investment and operation costs

Alternative	**Investment**	**Operation**	**Total**
	million US$ (1998)	million US$ (1998)	million US$ (1998)
Base Case	9 548	44 871	54 419
Alternative E_1	8 001	37 490	45 491

For the Base Case and the Alternative E_1, Table 4.31 shows the annual environmental emission from power generation in the years 1998, 2010 and 2024. It may be noted that the annual emissions of CO_2 and NO_X in the Base Case will increase by 138% and 53%, respectively, over the study period, while the emissions of SO_X and particulate will decrease by 78% and 83%, respectively over the same period.

Table 4.31 Annual environmental emissions from power generation

	1998		2010		2024	
	Base case	**Alternative E_1**	**Base case**	**Alternative E_1**	**base case**	**Alternative E_1**
	million ton	million ton	million ton	million ton	million ton	million ton
UCO_2	81 982.78	81 982.78	109 266.80	110 350.06	195 519.76	195 516.70
	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton
CSOx	1 537.94	1 537.94	533.78	533.78	344.00	356.58
USOx	1 537.94	1 538.50	533.78	581.01	344.00	344.03
	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton
CNOx	221.31	221.31	242.27	242.27	338.01	315.16
UNOx	221.31	221.31	242.27	246.34	338.01	338.02
	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton	thousand ton
CParticulate	93.88	93.88	27.58	27.58	16.27	17.02
UParticulate	93.88	93.88	27.58	30.42	16.27	16.27

For the Alternative E_1, the annual emissions of CO_2 and NO_X will increase by 116% and 42%, respectively, over the study period, while the emissions of SO_X and particulate will decrease by 76% and 82%, respectively, over the same period.

In the year 2024, the emissions of SO_X and particulate are higher as compared with the emissions for the Base Case, however, the emissions of CO_2 and NO_X, are lower than in the Base Case.

Finally, for a discussion of the results of the alternative of 8% discount rate (Alternative E_2) and the alternatives of increased reliability (Alternative F_1), decreased reliability (Alternative F_2) and decreased reserve margin (Alternative F_3) see Appendix G.

5. TOTAL ENERGY SYSTEM ANALYSIS

For the second phase of the project entitled: "Comparative Assessment of Energy Options and Strategies until 2025”, the total energy system in Mexico was analyzed by using ENPEP model. This chapter and following chapter concentrate on this study. This chapter focuses on the scope of the ENPEP study, giving the various scenarios and their assumptions as well as the configuration of the total energy network in Mexico.

5.1. Scope of total energy system analysis

The specific objectives of the study were:

- To identify domestic supply sufficiency for major energy resources, the long term need for energy imports, and the potential for energy exports;
- To study energy infrastructure development to support the growing energy use in Mexico;
- To analyze, in view of the projected high reliance of the power system and other demand sectors on natural gas, the development of the gas sector in detail in order to identify possible supply constraints, price implications and relevant policy measures:
- To identify the potential role of renewable energy sources in the Mexican energy system;
- To quantify environmental emissions of the whole energy sector associated with the expected growth of energy consumption and possible emission mitigation measures;
- To provide, by considering several alternative scenarios, a set of possible scenarios as input to national decision-making in the energy sector.

Therefore the modeling scope includes the energy supply sectors (oil, gas, coal, nuclear and renewable energy sources), energy conversion sectors (coal processing, oil refining, gas processing, power generation, etc.), energy transportation and distribution (distribution of oil, gas, and refinery products, coal distribution, electricity transmission and distribution, etc.), energy use at the demand side (modeled at the level of final or useful energy as appropriate) and emissions.

The studies comprise four case analyses based on the different scenarios — baseline scenario and three alternative scenarios. The entire energy system network is configured in a way that the various alternative scenarios analyses could be carried out.

The reference case — baseline scenario — corresponds to the unlimited supply of natural gas, either domestic or imported natural gas or both. The main assumptions for this scenario are:

- Utilize domestic resources to the extent possible
- Maintain energy diversity and avoid dependency on a single source
- Increase the use of natural gas, considering unlimited supply of natural gas; not just in the availability of this energy source but also for availability of the infrastructure for the transportation and distribution of the energy source;
- Consider utilization of advanced environmentally friendly technologies in the energy supply system;

- Study period: 1999 to 2025;
- The data for the base year will the data corresponding to the year 1999;
- An annual GDP average growth rate of 4.5% for the period from 2002 to 2011 and a 3.5% for the period 20012 to 2025;
- A population scenario with annual average growth rates of 1.33% for the period 2000 to 2010, 1.02% for the period 2011 to 2020 and a 0.82% for the last five years of the projection horizon;
- The annual demand growth rates for the sectors and sub-sectors will be determined under the two previous assumptions and the historical energy intensities through the energy projections obtained with the MODEMA model.
- The expansion of the power system (interconnected and isolated areas) will correspond to the unlimited gas scenario developed in phase I of the project;
- Real discount rate: 10%; and,
- All cost data will be expressed in constant 1999 U.S. dollars.

Alternative scenario 1 (Nuclear scenario): For this alternative scenario all the assumptions are identical to the ones established for the reference case, the only difference lies in the power sector through the inclusion of one unit of advance nuclear power plant with a capacity of 1,314 MW in 2012.

Alternative scenario 2 (Gas limitation scenario): As in the previous scenario all the assumptions are the same as in the reference case, except for the gas limitation, which is equivalent to a maximum of 3 combined cycle units per year. The complement of the expansion capacity is filled with 57 coal plants that use imported coal. Additionally, 3 more gas turbines are included in the expansion of the power sector.

Alternative scenario 3 (Renewable energy scenario): The renewables scenario focused on the introduction of additional wind and solar PV for power generation. Other renewables, e.g. mini-hydro and the application of renewables in the end-use sectors should be analyzed in future model runs. The model was configured such that solar and wind technologies compete with grid electricity on a national level, including the isolated system. Cost information was obtained from NREL and DOE-EIA. The technology assumptions are given in the following table:

	Wind Farm	**Solar**
Capacity	50 MW	5 MW
Average capacity factor	26.2%	20%
Efficiency	65%	15%
Fixed O&M cost	26.94 $/kW-year	10.2 $/kW-year
Initial capital cost	1,154 $/kW	4,781 $/kW
Experience factor	0.88	0.82

The experience factors for solar and wind essentially represents the cost reduction with each doubling of installed capacity. The resulting cost reductions for solar (from 4,781 to 1,773 $/kW) and wind (from 1,154 to 536 $/kW) over time are shown in Figures 5.1 and 5.2.

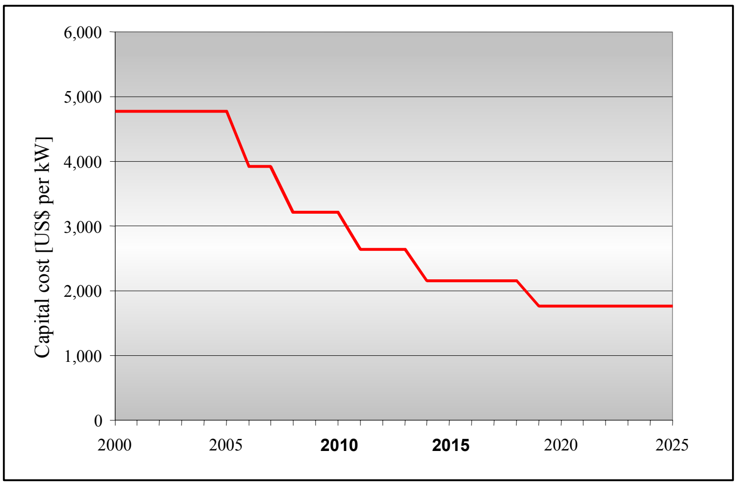

Figure 5.1 Solar photovoltaic capital cost curve (experience factor = 0.82).

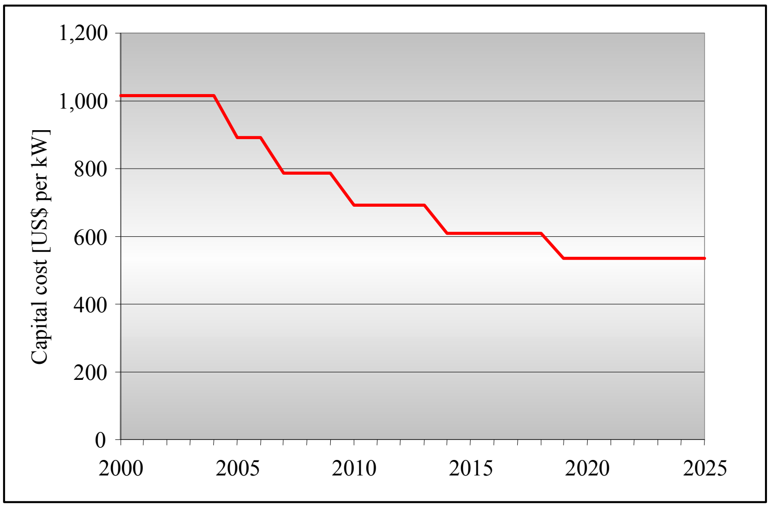

Figure 5.2 Wind capital cost curve (experience factor = 0.88).

5.2. Energy network configuration

For the analysis of the total energy system in Mexico, the entire energy network of the considered sectors was defined and developed in ENPEP's graphical user interface, as presented in Figure 5.3. Each sector was then defined at a level of detail that matches the available data for the sector and is appropriate for the types of issues to be analyzed.

Table 5.1 shows an explanation of the supply and demand sectors, demand sub-sectors, fuels and electricity distribution abbreviations in Figure 5.3. The Residential, Commercial and Public sector as well as the Transport and Agricultural sectors were split into the different demand sub-sectors and uses.

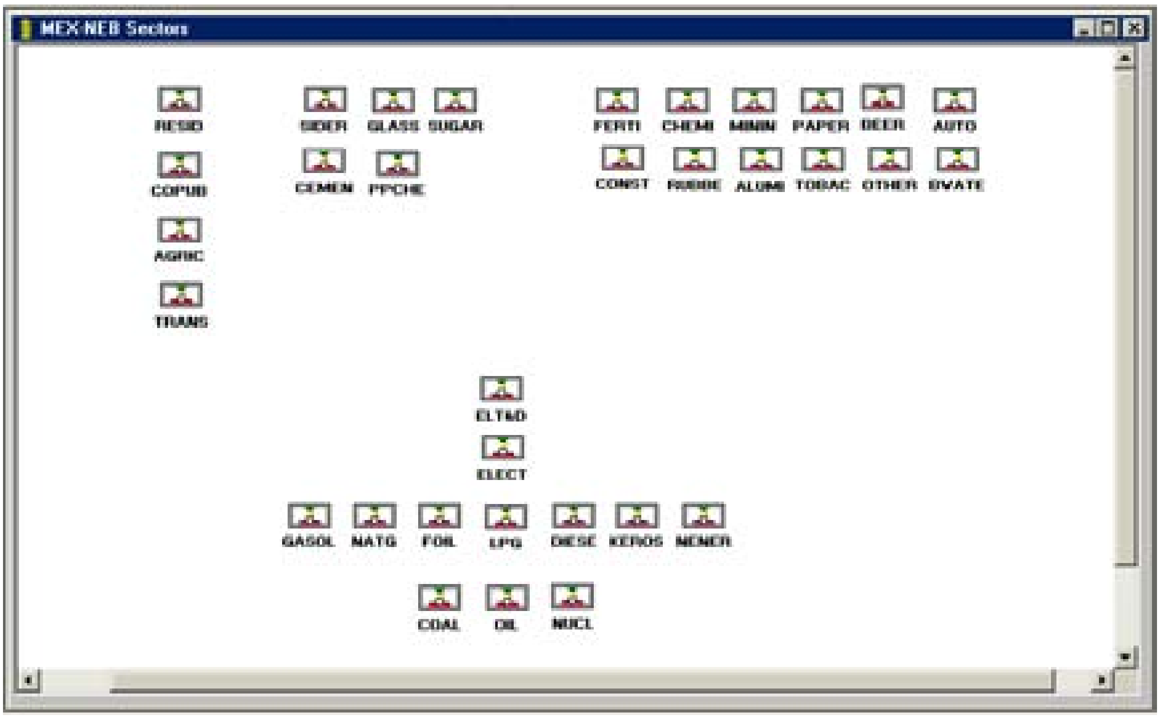

Figure 5.3 Mexican energy networks for the present study.

The individual sector networks are constructed using a set of ENPEP "building blocks" or nodes to model all energy flows, energy conversions, transmission/distribution, and pricing interventions from resource extraction or importation to consumption. The nodes that are used to construct the Mexican sectoral networks are shown in Figure 5.4, including a brief explanation on the main purpose of each of the nodes. The figure also provides information at which nodes the user can enter emission factors. In the Mexican network, emission factors for GHGs and other pollutants are specified for the following node types:

- Demand nodes
- Conversion process nodes

The renewable resources supply sectors are included in the sector networks for the power sector (hydro, geothermal and wind), the industrial sector (sugar cane bagasse), the residential sector (firewood and solar), the agricultural sector (wind, biomass and solar), as well as in the commercial and public sector (biomass and solar).

The import resource is displayed in each of the oil and gas sectors, coal sector and power sector. The imports sector contains imports of refined products (gasoline, kerosene, fuel oil, diesel and petroleum coke), imports of gas products (liquefied petroleum gas (LPG) and natural gas) as well as coke, thermal coal, nuclear fuel and electricity. Every one of these imports will be discussed in the specific sector.

Since Mexico is an energy exporter, the exports sector is displayed in each of the network sectors. Oil and gas sector includes exports of crude oil, natural gas and oil and gas products (gasoline, kerosene, diesel, fuel oil, non-energy products, natural gads and LPG). Coal sector includes exports of coal and coke and power sector includes exports of electricity.

Several economic activities make use of energy resources and fuels as raw material for their activities; specifically, the industrial sub-sector of PEMEX petrochemicals make use of non-associated natural gas, LPG, gasoline, kerosene, natural gas and non-energy products (lubricants, greases, asphalts, ethane, propane-propylene, butane-butadiene, sulfur, paraffines, etc.) and the others industrial sub-sector. Others make use of sugar cane bagasse, petroleum coke, LPG and the mentioned non-energy products. In order to take into account these uses of the energy resources; it was introduced the distribution node NENER and connected to these two industrial sub-sectors.

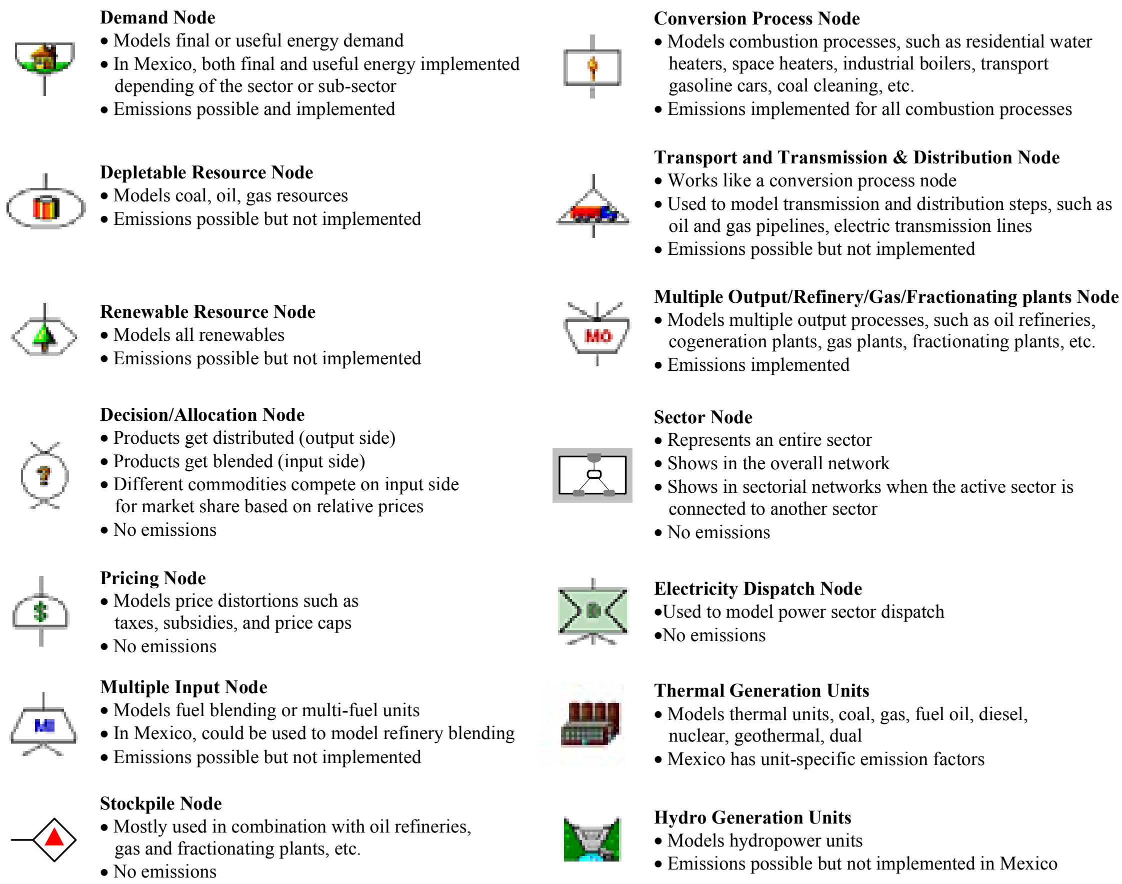

Figure 5.4 ENPEP node types used in the Mexican network.

5.2.1. Conversion, transmission and distribution sectors

In the Mexican energy sector three sectors are in charge of the conversion, transmission and distribution of energy. These sectors are the oil and gas sector, the power sector and the coal sector. As mentioned earlier, oil and gas supply sector includes oil refining, gas processing and gas liquids fractionation, as well as the oil and gas products distribution, including imports of gas and oil derivatives and exports of crude oil, natural gas and oil derivatives. On the other hand, power sector includes generation and distribution of electricity, as well as imports and exports of this energy source. Finally, coal sector includes processing and distribution of thermal and coking coal as well as imports and exports of coal and coke (see Chapter 5 for a complete discussion of the energy chains in the study).

5.2.2. Oil refining, gas processing and distribution sectors

A significant part of the crude oil production is associated with “associated gas”, the first assumption was to transform oil and gas production into energy units (PJ) and determine the ratio of oil and gas in the total energy amount. In order to determine this ratio, it was analyzed the fraction of gas associated to the crude oil along the period 1965–2000.

Table 5.1 Sectors, sub-sectors, fuels and electricity abbreviation nodes

Supply sector	**Demand sector and sub-sector**	**Fuels and electricity distribution**
COAL: Coal supply	RESID: Residential sector	GASOL: Gasoline distribution
OIL: Oil and natural gas supply	COPUB: Commercial and Public sector	NATG: Natural gas distribution
NUCL: Nuclear supply	AGRIC: Agriculture sector	FOIL: Fuel oil distribution
ELECT: Electricity supply	TRANS: Transport sector	LPG: LPG distribution
	SIDER: Iron and steel sub sector	DIESE: Diesel distribution
	GLASS: Glass sub-sector	KEROS: Kerosene distribution
	SUGAR: Sugar sub-sector	NENER: Non energy products distribution
	CEMEN: Cement sub-sector	ELT&D: Electricity distribution
	PPCHE: PEMEX Petrochemical sub-sector	
	FERTI: Fertilizers sub-sector	
	CHEMI: Chemicals sub-sector	
	MININ: Mining sub-sector	
	PAPER: Paper and cellulose sub-sector	
	BEER: Beer and malt sub-sector	
	AUTO: Automotive sub-sector	
	CONST: Construction sub-sector	
	RUBBE: Rubber sub-sector	
	BWATE; Bottled soft waters sub-sector	
	ALUMI: Aluminum sub-sector	
	TOBAC: Tobacco sub-sector	
	OTHER: Other sub-sectors	

From this analysis it was concluded that a ratio of 81.35% crude oil and 18.65% associated gas would be incorporated, through a dummy multiple output node, to the structure of the oil and gas supply sector (Figure 5.5). Clearly, in the future this relation could change and, as the consequence, it will be convenient to determine the future evolution of this ratio. The current structure of the sector allows introducing a ratio for every single year, so this modification to the present structure of the sector will depend on the available information for the future production of crude oil and associated gas.

The non-associated gas and condensates are included as separated streams. Non-associated gas is send to the gas processing plants node and, according to the current structure of the national refining and fractionating system the condensates stream is split into to streams, one is send to the National Refining System (NRS) node and the other to the fractionating system node (Figure 5.5).

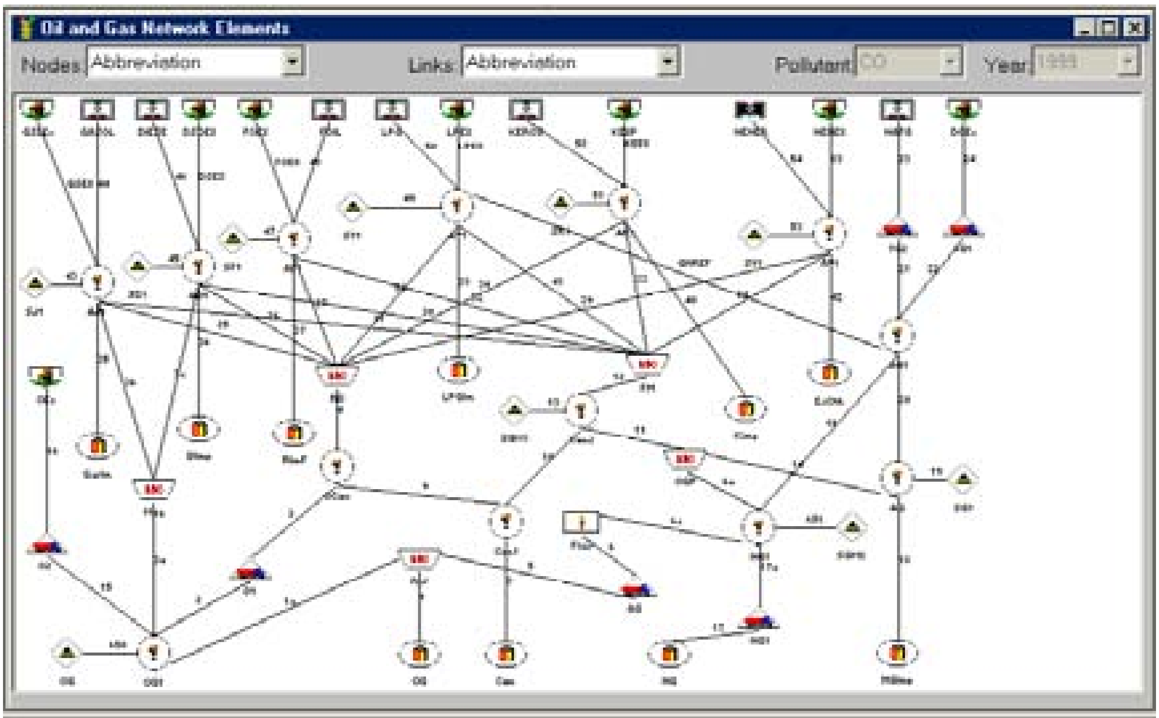

Figure 5.5 Oil, gas and condensates network.

The domestic production of crude oil is split into three streams, the first stream is send to the NRS node, the second to the Maquila's node and the third one to the exports node. The NRS node consists of a single refinery with a total capacity of 1.56 million barrels per day representing the existing 6 refining utilities. In the Maquila's node, part of the demand of oil products, not produced in the country, due to the present refining capacity and lack of investment in the expansion of this refining capacity, is covered.

Due to programming limitations of the multiple output nodes, at the present, the node representing the NRS node in the oil and gas sector, only take into account six oil products. Therefore, it was decided to take into account the following refinery products: gasoline, diesel, fuel oil, LPG, kerosene and non-energy products. The natural gas production from the NRS was added to the LPG production and split in the corresponding fraction for end use.

A very recent programming modification allows multiple output nodes with up to 15 output products and a future improvement of the Mexican oil and gas sector would be to take advantage of this modification, depending on the availability of the information, upstream and downstream, in the sector. Refinery products are sent to the allocation nodes, which are de responsible for their allocation to the internal distribution nodes and to the exports nodes. A multiple output node, with two outputs, represents gas plants with gas liquids and natural gas as outputs. Gas liquids are send to fractionating plants and natural gas to the corresponding allocation node for allocation to the internal distribution nodes and to the exports nodes. Fractionating plants are, also, represented by a multiple output node and their output products are sent to the corresponding allocation nodes for allocation to the internal distribution nodes and to the exports nodes.

Resource nodes representing excess demands for oil products, natural gas and other products are also included. These resource nodes are connected to the allocation nodes, with their corresponding stockpile for the first year, and, as was mentioned, the allocation nodes allocate the oil and gas products to the internal distribution nodes and to the country's exportations of oil products, natural gas and non-energy products.

The oil product distribution sectors comprise seven products, including gasoline, fuel oil, diesel, kerosene, non-energy products, liquefied petroleum gas (LPG) and natural gas as included in the oil and gas network (Figure 5.6). Gasoline production comes from the refining and fractionating nodes, as well from the maquila, exports and imports nodes in the oil and gas network.

Figure 5.6 shows the gasoline distribution network. Gasoline is split, through an allocation node, into two final uses, *i.e.,* as energy source and as raw material. Final end use sectors are the transport sector and two industrial sub-sectors. The transport sector uses gasoline for road and air transportation. On the other hand, PEMEX Petrochemicals (PPCHE) and some industrial branches (OTHER) use gasoline as a raw material in their activities.

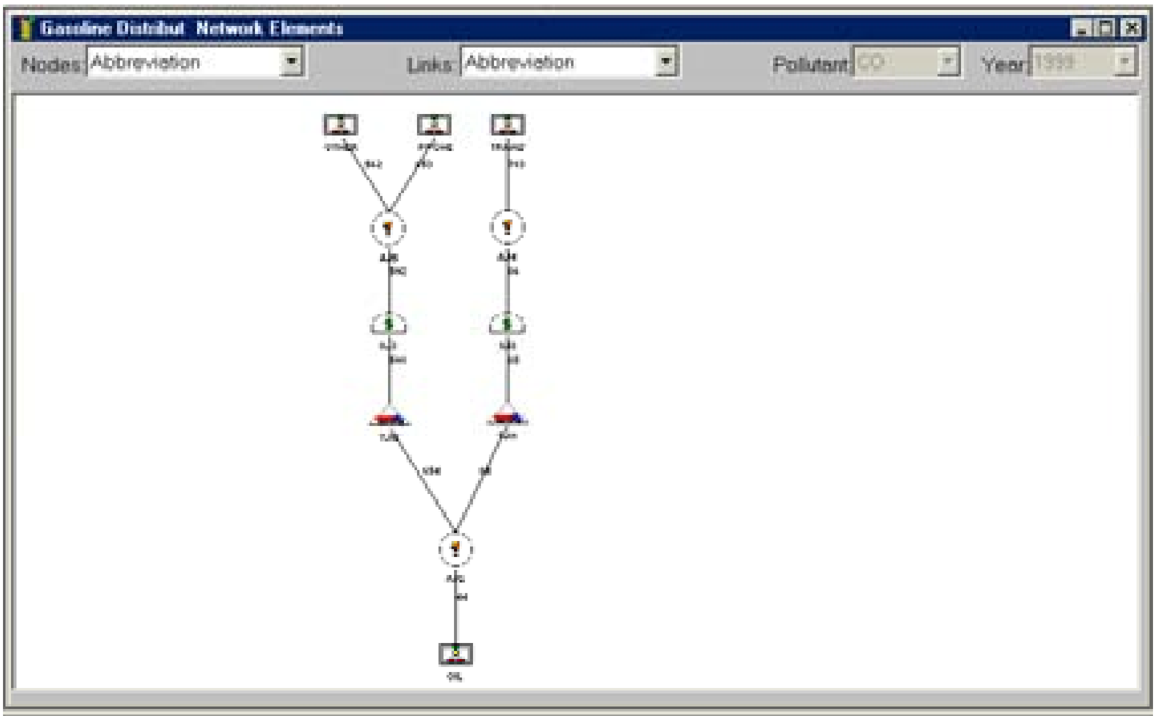

Figure 5.6 Gasoline distribution network.

Fuel oil is an output product from the refining, fractionating, exports and imports nodes. Figure 5.7 shows the fuel oil distribution network. Fuel oil is split into some of the end use sectors (power sector, sea transportation, and industry (except in the automotive, construction and aluminum sub-sectors). The rest of the end use sectors (commercial, residential, public and agricultural) do not make use of this energy fuel. Diesel is an output product of the refining, fractionating, maquila, and exports and imports nodes. Figure 5.8 shows the diesel distribution network. Diesel is consumed in almost all the sector and sub-sectors of the Mexican energy system. The exceptions to these aspects are the residential sector; the industrial sub-sectors of cement and aluminum and the air and electric transportation sub-sectors. Diesel is not use as a raw material input in any of the sectors and sub-sectors.

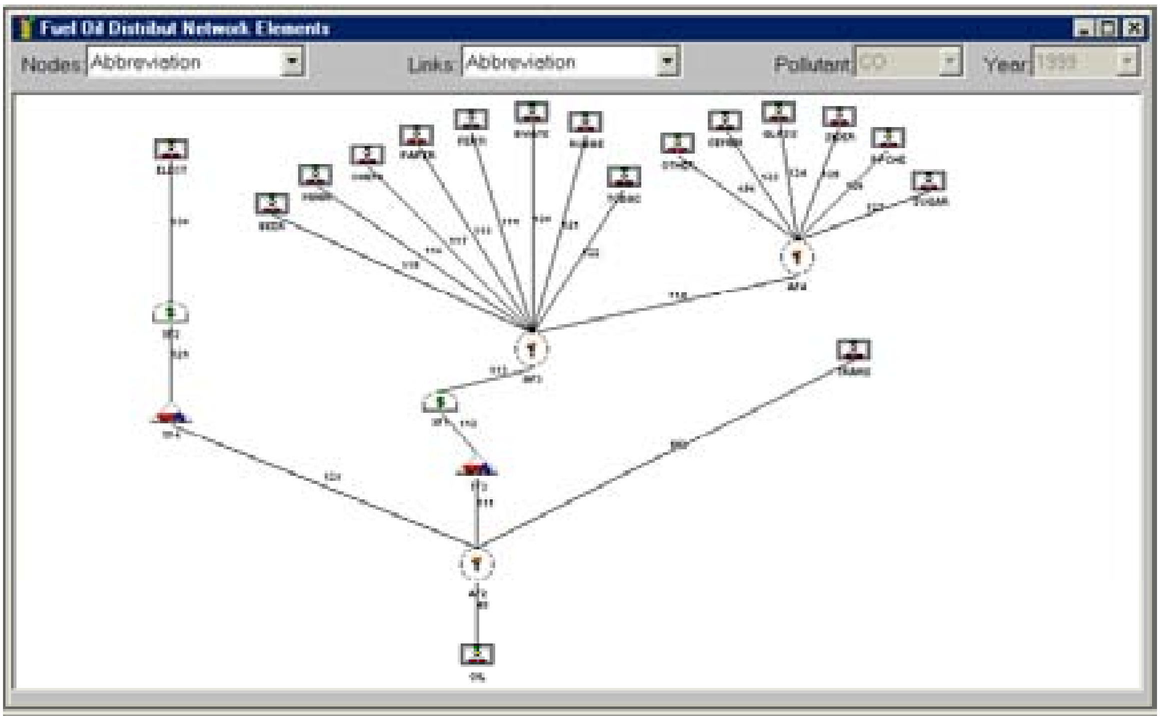

Figure 5.7 Fuel oil distribution network.

Kerosene is an output product of the refining, fractionating, exports and imports nodes. Figure 5.9 shows the kerosene distribution network. Kerosene is consumed in some of the sector and sub-sectors of the Mexican energy system. The sectors in which there is not kerosene consumption are: the commercial and public sectors; all the industrial sub-sectors with the exception of the OTHER and PEMEX Petrochemicals (PPCHE) sub-sectors and all the transport sub-sectors with the exception of the air transportation sub-sector. Kerosene is used as a raw material input in the OTHER and PEMEX Petrochemicals sub-sectors.

Another kind of oil product is the non-energy products that consist of greases, lubricants, asphalts, paraffines, etc. The final amount of these products is a result of the refining, fractionating, exports and imports nodes (Figure 5.5). Figure 5.10 shows the non-energy products network. According to the National Energy Balance these products are consumed, as a raw material, in the PEMEX Petrochemicals (PPCHE) and OTHER sub-sectors. It is well known that non-energy products are consumed as a raw material in almost all the sectors and sub-sectors the National Balance does not provide any splitting between the sectors and sub-sectors, except for the two sub-sectors already mentioned.

Liquefied petroleum gas (LPG) is an output product of the refining, fractionating, exports and imports nodes. Figure 5.11 shows the LPG distribution network. LPG is consumed in almost all the sectors and sub-sectors of the Mexican energy system. However, LPG consumption is highly located at the residential sector, over 80% of the total LPG consumption in the country and 43% of the total energy consumption in the residential sector. The sectors and sub-sectors in which there is not LPG consumption are: the public sub-sector; the industrial sub-sectors of PEMEX petrochemicals, fertilizers and construction and all the transport sub-sectors with the exception of the road transport. LPG is used as a raw material input in the OTHER and PEMEX Petrochemicals sub-sectors.

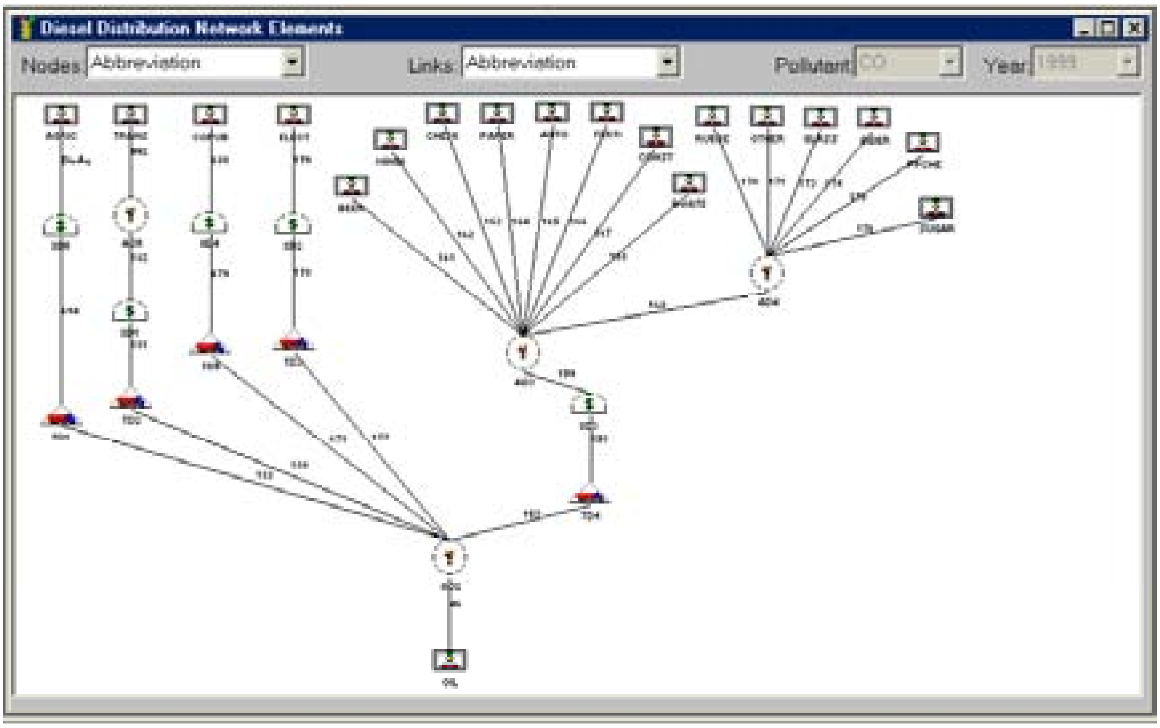

Figure 5.8 Diesel distribution network.

Finally, natural gas is an output product of the refineries and gas plants processing, exports and imports nodes. Figure 5.12 shows the natural gas distribution network. Natural gas is consumed by almost all the sectors and sub-sectors of the Mexican energy system. Presently, the Mexican government has an important natural gas penetration policy in most of the sectors (power sector, industrial, transport, residential and commercial); however, the success of this policy will depend on a real development of the gas production and its transportation and distribution structure. The sectors in which there is not natural gas consumption are: the public sector; the industrial sub-sectors of construction and sugar; all the transport sub-sectors with the exception of the road transportation sub-sector and the agricultural sector. Natural gas is used as a raw material input in the OTHER and PEMEX Petrochemicals sub-sectors.

5.2.3. Coal and coke production, processing and distribution sectors

Figure 5.13 shows the production, processing and distribution sectors of coal for thermal uses and coke in the Mexican energy system. There are two thermal and coking coal resource streams: domestic (thermal and coking coal) and imported thermal coal. Domestic thermal and coking coal is split, at an allocation node, into three streams: the main stream, 43.87% of the total domestic production, consists of thermal coal that does not require any treatment and goes directly to the end use (to the power sector generation and, perhaps, in the future, to the industrial sector); at the second stream, 21.08% of the thermal coal production is washed and send to final use; and, for the third stream, the metallurgical coal (35.05% of the total coal production) is washed and together with the imported coking coal is send to the coking process node. A small part of the domestic production of metallurgical coal, after the washing process, is exported.

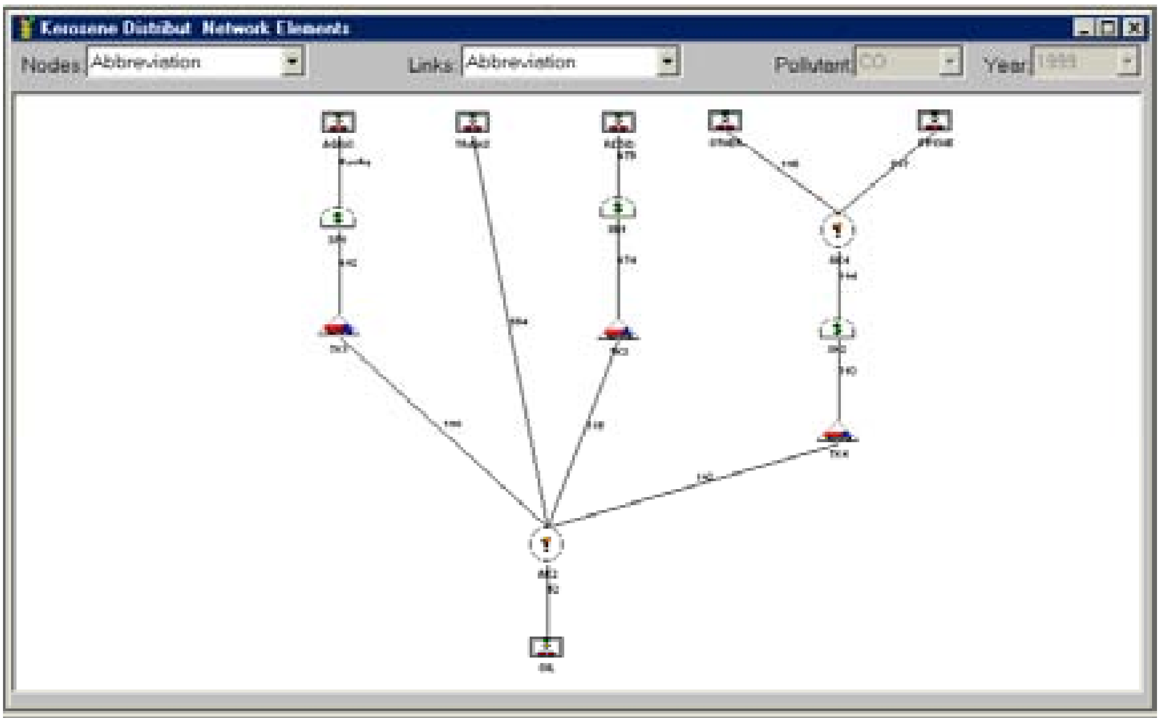

Figure 5.9 Kerosene distribution network.

At this point, is important to mention the following: the data for coal production, reported at the National Energy Balance, correspond to the metallurgical and thermal coal production after the washing process. Therefore, the comparison between the data in the National Energy Balance and the BALANCE structure and results for this resource, energy fuel and raw material has to be carried out after the washing process for both, metallurgical and thermal coal.

For coke there are three resource streams: imported coke and imported and domestic coking coal. Imported coke goes directly to end use industrial activities; whereas imported metallurgical coal is send to the coking process and from there to the end use in several industrial activities (industries such as iron and steel, cement, glass and mining) and to exportation.

5.2.4. Nuclear production, processing and distribution sectors

Figure 5.14, shows the nuclear distribution network based on domestic and imported uranium resources. The nuclear network includes uranium conversion, enrichment and fabrication process and final use in electricity generation as well as uranium exports. Mexico has some level of uranium resources but is not exploiting this energy resource. In terms of production, there is a sub-product of an equivalent of 47 tons of U_3O_8 of the molybdenum small industrial pilot plant. At present, the Mexican nuclear distribution network is reduced to the enriched uranium imports and its use in the power generation facility of Laguna Verde.

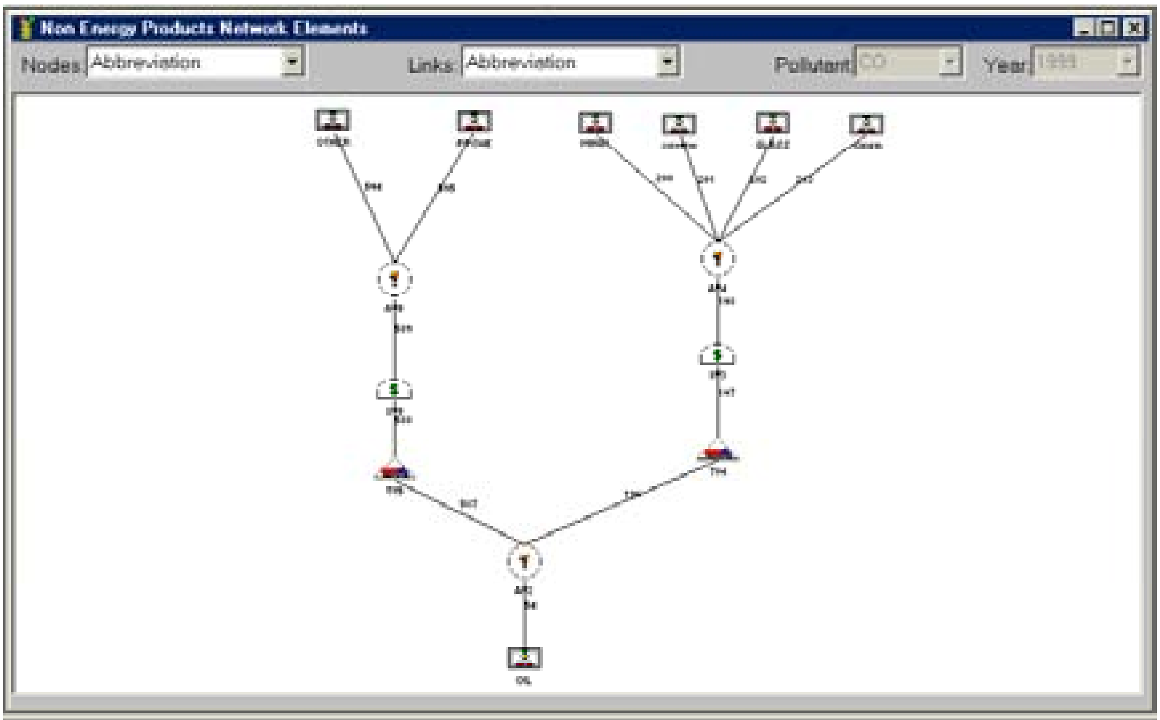

Figure 5.10 Non-energy products distribution network.

5.2.5. Electric power sector

Figure 5.15 shows the structure of the electric power sector for the Mexican Integrated Power System. As BALANCE does not perform a system expansion, in a typical ENPEP application, the expansion plan was determined by WASP (/DECADES) and DECADES then transferred to BALANCE. Using the BALANCE dispatch node and the thermal and hydro-unit nodes, BALANCE then dispatches the system unit-by-unit, and calculates unit-level generation, fuel consumption, and production cost for all existing and new units. As the BALANCE dispatch is using a somewhat different approach than the WASP dispatch, minor discrepancies may occur that are usually of no concern given the long time frame of the analysis. The existing capacity in 1999 in the National Power System was 35.7 GW, of which 27.97% was hydro capacity and 73.03% thermal capacity. After some additions and retirements, in 2001 total capacity of the National Power System was 38.5 GW, of which 25% was hydro and 75% thermal. Besides the additions and retirements during 2000 and 2001 there were additions under the modality of external energy producer, 484 MW in 2000 and 972.4 MW in 2001.

On the basis of the last prospective study for the Mexican power sector[20], during 2002, some thermal units will be added representing an addition of 2,577 MM to the existing capacity. On the other hand, some thermal, hydro, geothermal units that are already under construction or committed will be added along the period 2003-2008. These additions, under the modalities of construction, adjudicated, in bidding process and entering into the bidding process, represent a total addition of 11,651 MW for the period 2003-2008. For the period 2002-2008, total committed capacity is 14,228 MW, 80% with the combined cycle technology and 13% on the basis of renewable sources and the projects under the modality of construction are already in commercial operation and represent 16% of the committed capacity.

[20] Prospectiva del Sector Eléctrico 2002-2011, SENER, México, 2002.

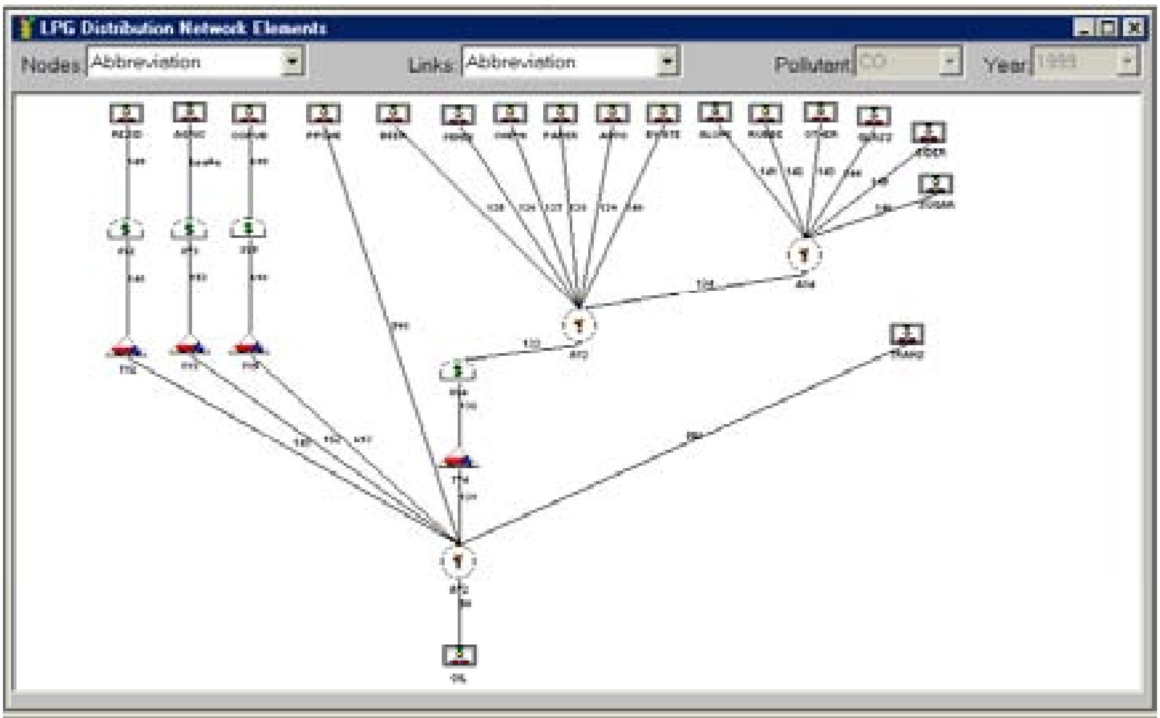

Figure 5.11 Liquefied petroleum gas (LPG) distribution network.

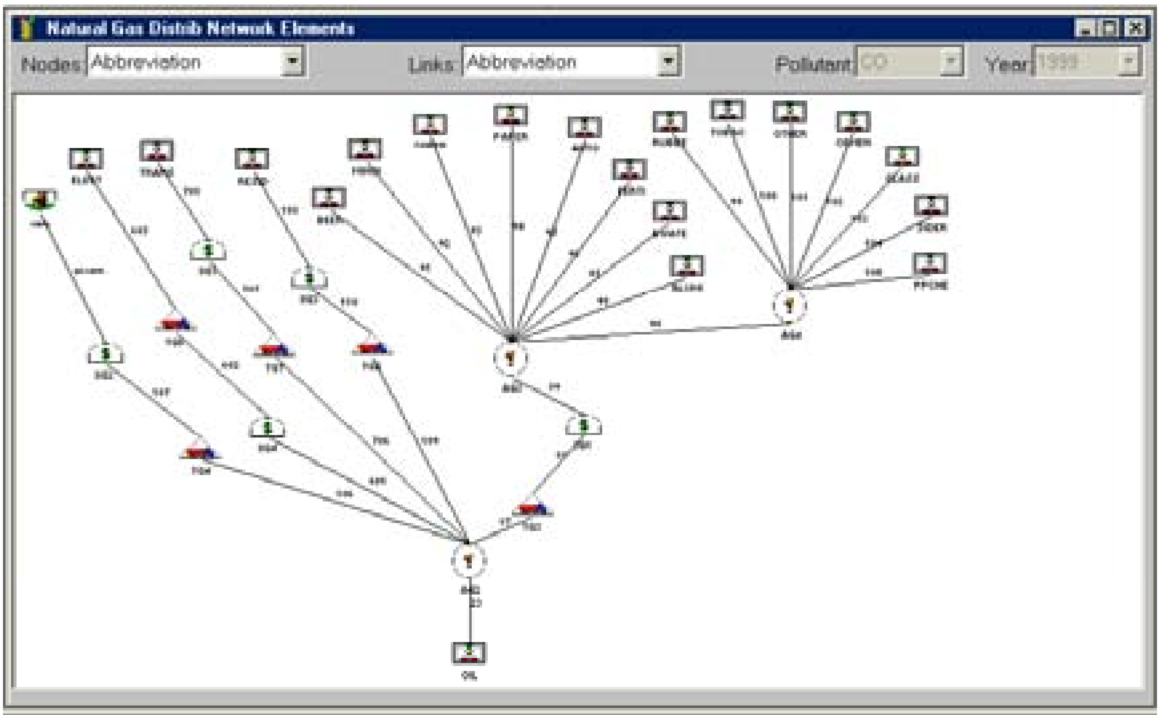

Figure 5.12 Natural gas distribution network.

The lower part of Figure 5.15 shows the coal (COAL), fuel oil (FOIL), diesel (DIESE), nuclear (NUCL) and natural gas (NATG) energy supplies for electricity generation; on the lower-right-hand-side part the geothermal resource for electricity generation and at the left-hand-side the hydro sector for electricity generation (HYDRO). For more detail of the network:

- Coal is split into the dual units node (FMIX, with 6 units) and the coal units node (COAL, with eight units);

- Fuel oil is split into three generation nodes: dual units node (FMIX, with six units), fuel oil units node (FOSTE, with 23 units) and the third portion is send to the electricity transmission and distribution node (ELT&D) for use in the generation units at the isolated regions;

- Diesel is split into the diesel gas turbines units node (DSLTG, with 21 units) and the electricity transmission and distribution node (ELT&D) for use in the generation units at the isolated regions;

- Nuclear is split into the nuclear units node (NUCL, with two existing nuclear units);

- Natural gas is split into four generation nodes: gas turbine units node (GASTU, with six units), independent power producers units node (IPPS, with five units), combined cycle units node (CC-TG, with 130 units, 12 existing in 1999 and 118 for the projection period) and the four portion is send to the electricity transmission and distribution node (ELT&D) for use in the generation units at the isolated regions.

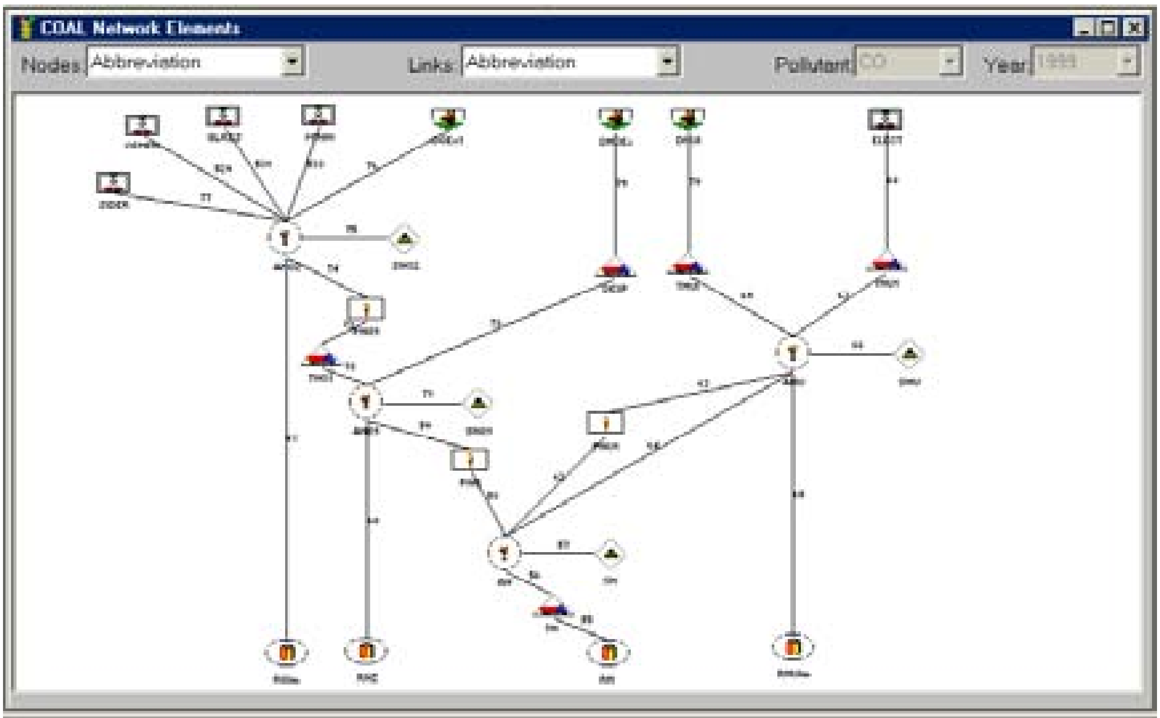

Figure 5.13 Coal and coke distribution network.

- The geothermal energy resource is split into two portions, the first portion is used at the geothermal units node (GEOTH, with five existing units and two to enter in operation by 2002; these two new units are the ones considered in the projection horizon but incorporated to the fixed system to avoid the creation of an additional category in the VARSYS module of WASP) located at the interconnected system and the second portion is send to the electricity transmission and distribution node (ELT&D) for use in the geothermal units located at the isolated regions.

- Hydro is split into the hydro units node (HYDRO, with 23 existing hydro units and five new expansion projects).

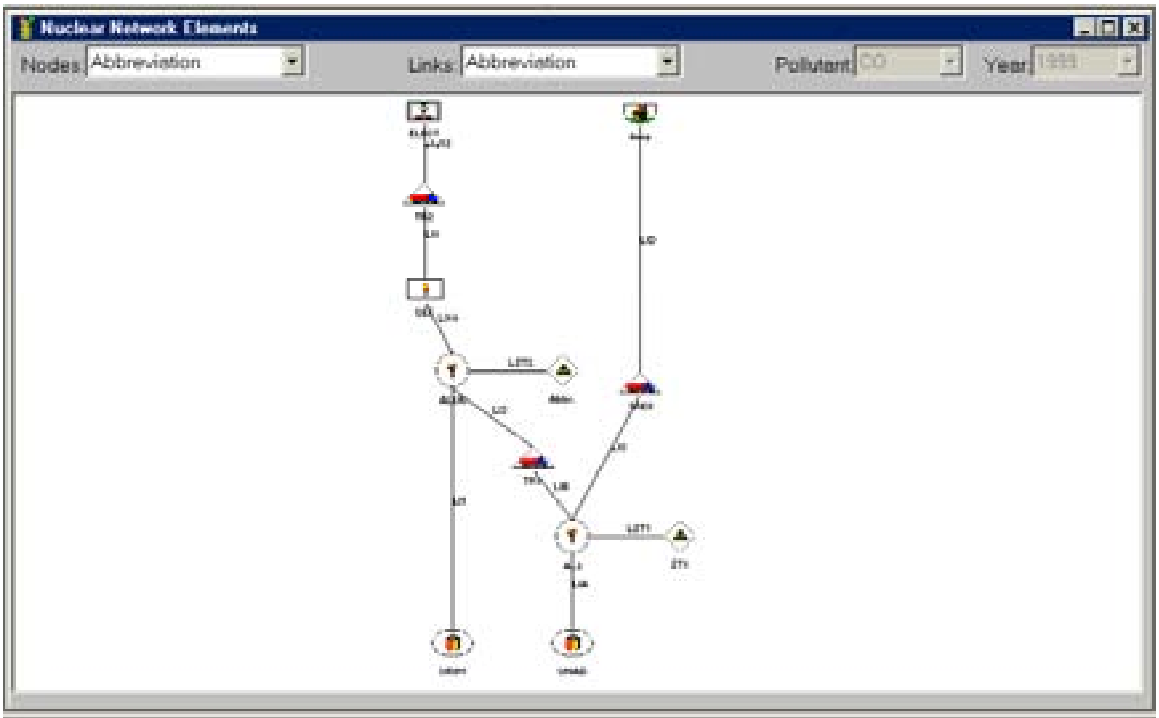

Figure 5.14 Nuclear distribution network.

It is important to mention that the main portion of the geothermal development for electricity generation is located at the isolated region of Baja California and that a very small portion of this geothermal development is located in two of the interconnected regions. In the discussion of Chapter 2 it was indicated that the capacity expansion include two geothermal units of 50 MW each and that they were included in the fixed system avoiding an additional category in the VARSYS module of the WASP model.

As was mentioned in Chapter 4, the Mexican power system is divided into nine regions in terms of generation regions, six of them are interconnected and three are isolated. Since, we are using the BALANCE dispatch for the interconnected system (Figure 5.15) and this dispatch is using a somewhat different approach than the WASP dispatch, minor differences could be expected.

On the other hand, the isolated[21] regions are not connected to the rest of the system and, as a consequence, they can’t be connected to the BALANCE electric dispatch node, therefore the modeling of the isolated regions followed a slightly different approach. Figure 5.16 shows the electricity transmission and distribution sector and in the lower left-hand-side of the figure appears the modeling of these isolated regions using a combination of allocation, conversion process and resource nodes.

For the modeling of these isolated regions, Table 5.2 shows the split of the electrical capacity into the Interconnected System and the isolated regions. The comparison of Table 5.2 and Table 5.22 shows that, for the years 1997 to 1999, the total capacity in the system is the same

[21] The isolated generation regions are Baja California, Baja California Sur and Northwest regions, in the years 2001 and 2002 there were some efforts to reinforce the interconnection of the Interconnected System (six regions) with the Northwest region, therefore, it appears that the two Baja California regions are the only ones isolated.

and that, for the years 2000 and 2001, there is a difference due to the additions indicated at the notes in the table's footnote.

On the other hand, the isolated[22] regions are not connected to the rest of the system and, as a consequence, they can't be connected to the BALANCE electric dispatch node, therefore the modeling of the isolated regions followed a slightly different approach. Figure 5.16 shows the electricity transmission and distribution sector and in the lower left-hand-side of the figure appears the modeling of these isolated regions using a combination of allocation, conversion process and resource nodes.

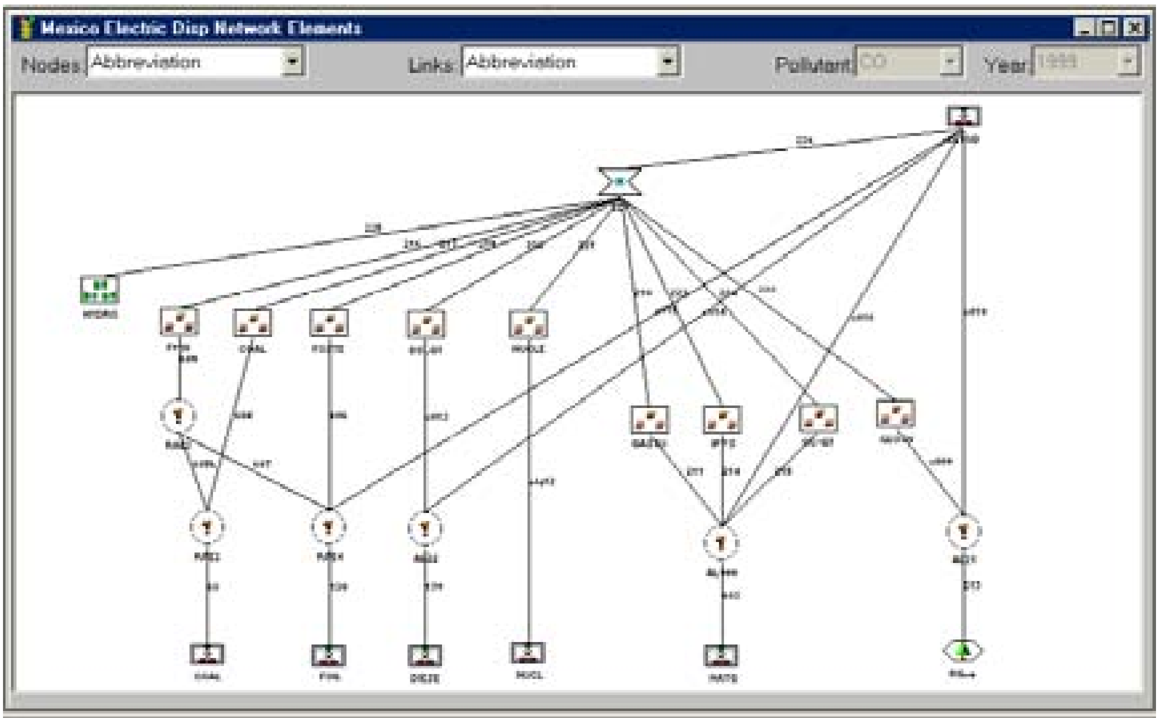

Figure 5.15 Electric power sector (interconnected system).

For the modeling of these isolated regions, Table 5.2 shows the split of the electrical capacity into the Interconnected System and the isolated regions. The comparison of Table 5.2 and Table 5.22 shows that, for the years 1997 to 1999, the total capacity in the system is the same and that, for the years 2000 and 2001, there is a difference due to the additions indicated at the notes in the table's footnote.

The modeling approach for the isolated regions was to consider the fulfillment of the generation demand along the projection period rather than the expansion of capacity in those regions. Therefore, through the use of the processes, links and allocation nodes shown in the lower left-hand-side part of Figure 5.16 the renewable energy sources (hydro and geothermal) and the fossil energy sources (fuel oil, natural gas and diesel) are transformed into electricity and the generation demands for each of the isolated regions along the projection years are satisfied.

[22] The isolated generation regions are Baja California, Baja California Sur and Northwest regions, in the years 2001 and 2002 there were some efforts to reinforce the interconnection of the Interconnected System (six regions) with the Northwest region, therefore, it appears that the two Baja California regions are the only ones isolated.

Besides the inclusion of three additional resource nodes: solar (Rsol), minihydro (Mhyd) and Wind (Rwind), processes and allocations. Of these three resource streams, only the corresponding one to the wind resource was feed with data. The other two are ready for the necessary information, if available, and they correspond, respectively, to the possibilities of solar energy capture and its transformation into electricity and to the use of small hydro resources for electricity generation.

The rest of the nodes include, a resource node for electricity imports (ELimp), transport nodes, price nodes, sector and sub-sector nodes for the final demands of electricity.

5.3. Demand side sectors

The demand sectors represent the energy consumers. This is where the model projects fuel substitution trends based on relative prices and other factors. In an ideal application, the user can draw on detailed sectoral information regarding the energy services needed by a particular sector (direct heat, industrial steam, residential water heating, etc.), a breakdown of fuel consumptions by energy service, the technologies used to provide the service (boilers, furnaces, etc.), and technology performance parameters (e.g. process efficiency). This information is typically obtained by conducting detailed sector surveys for industry, transport, households and others.

As input to the BALANCE model, the aggregate demand growth rates for final energy were analyzed using MODEMA model. According to MODEMA methodology, the input data consist on the evolution scenarios for the Gross Domestic Product (GDP) and the population, as well as the statistical fitting to the historical series for the energy indicators (energy intensities and the per capita consumption) along the projection horizon. For the sectors and sub-sectors fuel mix, MODEMA takes into account fixed fuel consumption structures for the whole period or user's specification. For the present study, from the MODEMA's results, only the aggregate demand growth rates for final energy were used for all the sectors and sub-sectors in the present study.

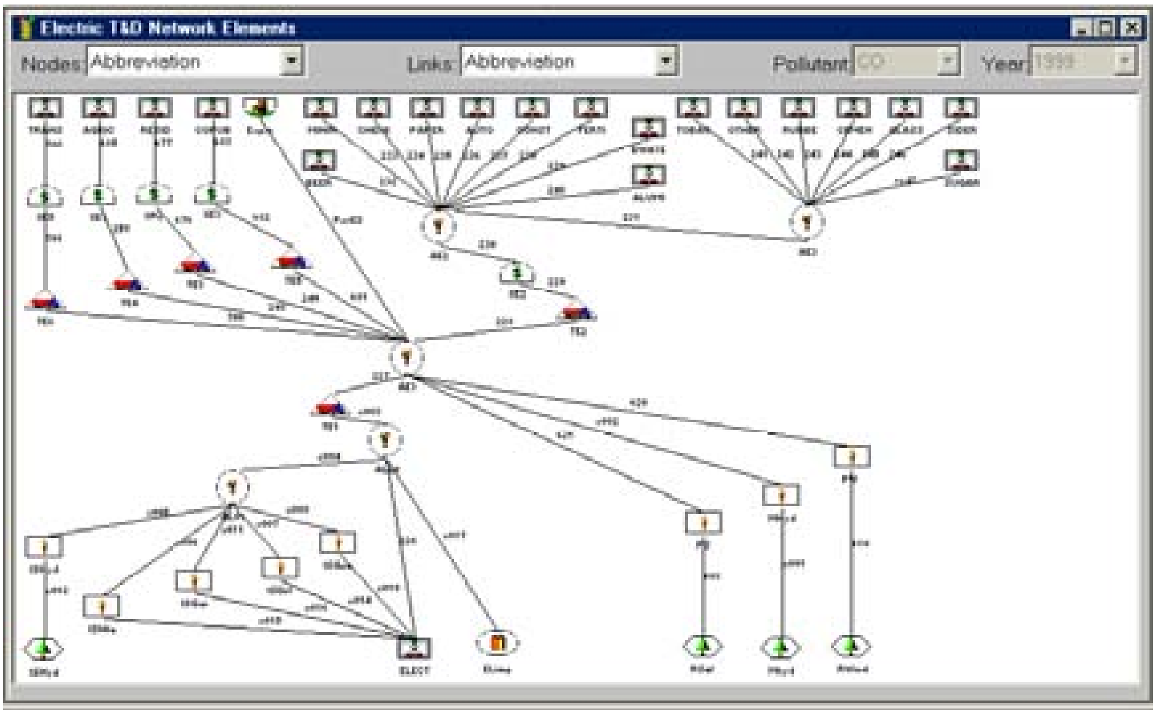

Figure 5.16 Electricity transmission and distribution network (generation from interconnected and isolated regions).

Table 5.2 Splitting of the electrical capacity into the Interconnected System and the isolated regions

Installed capacity in the interconnected system and isolated regions (MW) 1997

Area	Hydro	Steam	Combined cycle	Turbo gas turbine	Internal combustion	Dual	Coal	Geothermal	Nuclear	Wind	Total
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Interconnected system	9 093.24	11 388.00	1 941.66	1 267.50	0.77	2 100.00	2 600.00	129.90	1 309.06	1.58	29 831.71
Northwest	941.20	2 162.00		130.00							3 233.20
Baja California		732.50		277.58	120.09			620.00			1 750.17
	10 034.44	14 282.50	1 941.66	1 675.08	120.86	2 100.00	2 600.00	749.90	1 309.06	1.58	34 815.08

Installed capacity in the interconnected system and isolated regions (MW) 1998

Area	Hydro	Steam	Combined cycle	Turbo gas	Internal combustion	Dual	Coal	Geothermal	Nuclear	Wind	Total
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Interconnected system	8 759.24	11 388.00	2 463.42	1 389.50	0.77	2 100.00	2 600.00	129.90	1 309.06	1.58	30 141.47
Northwest	941.20	2 162.00		231.89							3 335.09
Baja California		732.50		307.58	118.89			620.00			1 778.97
	9 700.44	14 282.50	2 463.42	1 928.97	119.66	2 100.00	2 600.00	749.90	1 309.06	1.58	35 255.53

Installed capacity in the interconnected system and isolated regions (MW) 1999

Area	Hydro	Steam	Combined cycle	Turbo gas	Internal combustion	Dual	Coal	Geothermal	Nuclear	Wind	Total
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Interconnected system	8 677.95	11 388.00	2 463.42	1 633.31	0.77	2 100.00	2 600.00	129.90	1 368.00	1.58	30 362.93
Northwest	941.20	2 162.00		272.89							3 376.09
Baja California		732.50		457.58	116.89			620.00		0.60	1 927.57
	9 619.15	14 282.50	2 463.42	2 363.78	117.66	2 100.00	2 600.00	749.90	1 368.00	2.18	35 666.59

Installed capacity in the interconnected system and isolated regions (MW) 2000

Area	Hydro	Steam	Combined cycle	Turbo gas	Internal combustion	Dual	Coal	Geothermal	Nuclear	Wind	Total
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Interconnected system	8 677.95	11 388.00	3 881.62	1 589.31	0.77	2 100.00	2 600.00	134.90	1 364.88	1.58	31 739.01
Northwest	941.20	2 162.00		281.39							3 384.59
Baja California		732.50		489.08	114.89			720.00		0.60	2 057.07
	9 619.15	14 282.50	3 881.62	2 359.78	115.66	2 100.00	2 600.00	854.90	1 364.88	2.18	37 180.67

Installed capacity in the interconnected system and isolated regions (MW) 2001

Area	Hydro	Steam	Combined cycle	Turbo gas	Internal combustion	Dual	Coal	Geothermal	Nuclear	Wind	Total
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Interconnected system	8 677.95	11 388.00	5 689.92	1 612.81	1.57	2 100.00	2 600.00	107.90	1 364.88	1.58	33 544.61
Northwest	941.20	2 162.00	457.86	281.39							3 842.45
Baja California		732.50	496.00	486.48	141.57			730.00		0.60	2 587.15
	9 619.15	14 282.50	6 643.78	2 380.68	143.14	2 100.00	2 600.00	837.90	1 364.88	2.18	39 974.20

Notes: For year 2000 the Peninsular region includes the addition of the combined cycle plant Mérida III with a capacity of 484 MW.

For year 2001 the Interconnected system includes the addition of two combined cycle plants: Northeast region (Nueva Rosita, 247.5 MW) and the Oriental region (Tuxpan II, 495 MW) and the isolated Northwest region the addition of the combined cycle of Hermosillo with a capacity of 228.93 MW.

Table 5.3 shows the growth rates structure, in terms of Great Divisions and Divisions, for the GDP scenario along the projection horizon. The projection horizon was divided into two parts, the first one from 2002 to 2011 with an annual average growth rate of 4.5% and the second one from 2012 to 2025 with and annual average growth rate of 3.5%. The Secretaría de Energía provided the first part, while the working team, considering the GDP annual average growth rate for the last 25 years, determined the second.

Table 5.4 shows the considered evolution scenario for the country's population. This population scenario corresponds to the medium projection of the Consejo Nacional de Población (CONAPO).

The annual demand growth rates for final energy, for the sectors and sub-sectors considered in the study, are shown in Tables 5.5, 5.6, 5.7 and 5.8. The demand growth rates are inputs for the demand nodes. The fuel choices in each sector and sub-sector come from the National Energy Balances. The team members based on their insights and information on the individual sectors and sub-sectors determined fuel substitution possibilities, that is, the network structure for each sector and sub-sector.

In the case of Mexico, no information was available on the specification of the energy services and technologies; however, some of the industrial sub-sectors were split into specific energy services by considering international data for process efficiencies. The remaining industrial demand sectors are, therefore, implemented at a final energy level. That is, energy services are not considered for these sub-sectors, and the fuel competition is based mostly on fuel prices. For all industrial sub-sectors a breakdown of fuel consumptions was carried out. For the transport sector the breakdown was performed in terms of the five sub-sectors discussed in the Summary, section 5.3. For the road sub-sector, the energy services approach is considered through the process efficiencies and the hybrid option. For the remaining transport sub-sectors the demand is implemented at a final energy level.

5.3.1. Industrial demand sector

The Mexican industrial sector is highly energy intensive and efficiency of main conversion processes used in this sector is still below that of other industrialized countries so it is expected that industrial energy consumption will increase importantly. In order to estimate future industrial energy demand in the model, the study was conducted with 17 industrial sub-sectors (Table 5.1) as it is presented in the National Energy Balance (PEMEX petrochemicals, iron and steel, cement, sugar, glass, chemicals, malt and beer, automotive, paper and cellulose, rubber, tobacco, aluminum, bottled waters, fertilizers, mining and others).

Apart from electricity growth rates which are calculated taking into account assumptions of the WASP run, the rest fuel growth rates for industrial sub-sectors comes from the MODEMA model assuming fixed structures for the whole period for every one of them. This growth rates also take into account specific policies as environmental restrictions aiming to reduce drastically the consumption of fuel oil in the industrial sector for the year 2006. While no significant policies aimed to promote renewable energy penetration are visualized in this sector, cogeneration development is carefully taken into account in the design of the industrial sector network.

Considering the limitations on information on the specification of the energy services and technologies, the energy consumption in this sector has been analyzed in detail only for five individual industrial branches. These sub-sectors are iron and steel, PEMEX-petrochemicals, sugar, glass and cement. In those sub-sectors fuel consumption is represented considering the needs of heat, steam and electricity and the different technologies used to provide these services. Self-generation and co-generation, as well as fuel substitution, were also considered in those sub-sectors.

Table 5.3 Great Division and Division Gross domestic product structure (1997–2025)

	1997	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
GD1	0.16	3.03	2.03	3.35	2.54	0.70	1.81	1.31	3.17	0.56	0.51	5.43	3.05	3.63	3.21
INDUST	9.25	6.32	4.20	6.56	-3.51	1.87	5.21	5.97	6.51	6.63	4.95	4.91	6.48	6.75	6.23
GD2	4.47	2.74	-2.09	4.03	-0.56	2.30	2.41	3.01	3.36	2.78	3.21	3.03	2.95	3.23	3.31
GD3	9.94	7.37	4.18	7.07	-3.90	1.43	4.98	5.71	6.31	6.52	4.98	4.78	6.10	6.32	5.72
DI	3.24	6.60	4.01	3.57	1.79	2.40	2.40	2.61	3.47	4.26	3.51	3.63	3.55	3.63	3.21
DII	10.45	3.85	3.05	5.30	-10.13	-3.80	3.51	3.91	5.17	4.66	4.11	4.33	5.15	5.23	4.81
DIII	6.74	4.41	0.46	1.05	-4.46	-2.20	1.81	2.31	2.27	2.96	2.61	2.43	2.45	2.53	2.11
DIV	12.69	5.95	4.94	2.62	-4.05	-1.60	3.71	4.01	3.97	4.86	3.61	2.93	2.65	1.73	1.31
DV	6.82	6.06	2.36	3.13	-4.28	1.10	3.90	4.31	5.06	4.78	4.01	3.33	4.15	4.33	4.11
DVI	5.93	5.20	1.80	5.85	-4.24	3.50	7.20	8.61	8.86	8.06	5.71	5.43	9.05	10.03	9.71
DVII	11.13	4.00	0.39	3.58	-5.66	-1.40	5.81	5.81	5.97	5.66	4.31	4.03	6.35	6.43	6.01
DVIII	19.06	11.48	6.88	13.90	-6.22	2.80	7.80	8.91	9.26	9.46	6.81	6.53	8.55	8.73	7.61
DIX	10.46	7.88	5.66	12.16	-0.65	1.60	3.81	5.51	5.17	5.06	3.61	3.43	4.85	5.03	4.61
GD4	9.28	4.22	4.99	5.00	-4.51	3.70	7.30	8.31	8.56	8.56	5.31	5.83	9.45	9.83	9.41
GD5	5.21	1.85	7.91	6.20	1.71	2.46	4.95	5.47	5.94	5.65	4.78	5.22	5.46	5.59	5.10
GD5.1	4.89	1.93	10.69	6.20	1.53	2.02	4.96	5.57	5.93	5.94	4.84	4.97	5.30	5.41	5.00
GD5.2	6.22	5.39	-6.21	6.20	3.10	2.87	7.14	8.16	7.80	7.95	6.60	6.44	7.00	7.28	5.88
Gd5.3	6.14	0.02	2.40	6.20	2.00	4.30	4.01	3.91	5.17	3.26	3.61	5.83	5.45	5.63	5.21
SERV	6.55	4.69	3.80	7.35	1.14	1.86	3.98	4.60	4.81	5.09	4.44	4.42	4.51	4.65	4.43
GD6	10.70	5.64	3.45	11.07	-1.29	0.50	4.40	4.91	4.56	4.78	4.91	4.23	3.85	3.93	3.51
GD7	9.93	6.67	7.79	12.68	2.81	3.00	4.91	6.01	6.67	7.26	5.41	6.23	8.35	8.23	7.81
GD8	3.73	4.61	3.87	4.49	4.09	4.40	4.90	5.51	5.76	6.08	4.81	4.53	4.35	4.43	4.01
GD9	3.35	2.87	2.10	2.96	0.51	0.60	2.20	2.61	3.06	3.08	2.91	3.23	2.65	2.93	3.21
SBI	10.63	5.57	5.86	6.25	6.23	5.40	4.01	4.61	4.87	4.76	4.21	4.43	4.75	4.93	4.51
VAB	6.78	5.02	3.75	6.92	-0.26	1.69	4.20	4.80	5.20	5.30	4.40	4.61	5.01	5.21	4.91
IMP	6.70	5.10	3.75	6.92	-0.28	1.69	4.20	4.80	5.20	5.30	4.40	4.60	5.00	5.20	4.90
GDP	6.77	5.03	3.75	6.92	-0.26	1.69	4.20	4.80	5.20	5.30	4.40	4.61	5.01	5.21	4.91

	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
GD1	2.34	2.47	2.59	2.71	2.82	2.93	3.03	3.13	3.22	3.31	3.39	3.47	3.54	3.61
INDUST	3.94	3.97	3.99	4.01	4.03	4.04	4.05	4.07	4.07	4.08	4.09	4.09	4.10	4.10
GD2	2.33	2.36	2.39	2.43	2.46	2.49	2.52	2.55	2.58	2.61	2.63	2.66	2.69	2.71
GD3	3.82	3.83	3.84	3.84	3.85	3.86	3.86	3.87	3.87	3.87	3.87	3.87	3.87	3.87
DI	2.74	2.71	2.68	2.65	2.62	2.59	2.57	2.54	2.52	2.50	2.48	2.47	2.45	2.44
DII	2.74	2.85	2.96	3.06	3.16	3.25	3.33	3.41	3.49	3.56	3.62	3.68	3.74	3.79
DIII	1.42	1.41	1.39	1.38	1.37	1.35	1.34	1.33	1.31	1.30	1.29	1.28	1.27	1.26
DIV	2.23	2.18	2.13	2.09	2.04	2.00	1.96	1.92	1.88	1.84	1.80	1.77	1.73	1.70
DV	2.89	2.92	2.94	2.96	2.98	3.01	3.03	3.04	3.06	3.08	3.10	3.12	3.13	3.15
DVI	4.79	4.89	4.98	5.05	5.11	5.17	5.21	5.24	5.27	5.29	5.30	5.30	5.30	5.30
DVII	3.45	3.54	3.63	3.72	3.80	3.87	3.93	3.99	4.05	4.10	4.14	4.18	4.22	4.25
DVIII	4.96	4.92	4.88	4.84	4.81	4.77	4.73	4.70	4.67	4.63	4.60	4.57	4.54	4.51
DIX	3.67	3.70	3.72	3.74	3.76	3.78	3.80	3.81	3.83	3.84	3.85	3.86	3.87	3.87
GD4	4.75	4.81	4.85	4.88	4.91	4.93	4.95	4.96	4.97	4.97	4.97	4.97	4.96	4.95
GD5	4.00	4.08	4.16	4.23	4.29	4.35	4.40	4.44	4.48	4.51	4.54	4.56	4.58	4.59
GD5.1	4.09	4.20	4.30	4.39	4.47	4.54	4.60	4.66	4.70	4.74	4.78	4.81	4.83	4.84
GD5.2	4.44	4.64	4.83	4.99	5.13	5.26	5.36	5.45	5.52	5.58	5.63	5.66	5.69	5.70
Gd5.3	3.34	3.23	3.13	3.04	2.95	2.87	2.79	2.71	2.64	2.58	2.51	2.45	2.40	2.34
SERV	3.39	3.36	3.34	3.32	3.29	3.27	3.26	3.24	3.22	3.21	3.20	3.18	3.17	3.16
GD6	3.20	3.12	3.04	2.97	2.90	2.84	2.78	2.72	2.67	2.62	2.57	2.52	2.48	2.44
GD7	4.75	4.78	4.81	4.83	4.84	4.85	4.86	4.86	4.86	4.86	4.85	4.84	4.83	4.82
GD8	3.59	3.51	3.44	3.37	3.30	3.24	3.18	3.13	3.08	3.03	2.99	2.95	2.91	2.87
GD9	2.26	2.28	2.30	2.31	2.33	2.35	2.37	2.38	2.40	2.42	2.44	2.46	2.47	2.49
SBI	3.66	3.56	3.46	3.37	3.29	3.22	3.14	3.08	3.01	2.95	2.90	2.84	2.79	2.75
VAB	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50
IMP	3.50	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.48
GDP	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50	3.50

GD1	Agriculture, silviculture and fishery	GD5	Electricity, dry gas and water
INDUST	Industrial sector	GD5.1	Electricity
GD2	Mining	GD5.2	Dry gas
GD3	Manufacturing industry	Gd5.3	Potable water
DI	Food products, drinks and tobacco	SERV	Services sector
DII	Textiles, clothes and leather products	GD6	Commerce, restaurants and hotels
DIII	Wood industry and wood products	GD7	Transport, storage and communications
DIV	Paper, paper products, printing and editing	GD8	Financial services, insurance, real state and leasing
DV	Chemicals, oil, plastic and rubber	GD9	Social, personal and community services
DVI	Non metallic mineral products (excludes oil and coal prods)	SBI	Banking services
DVII	Basic metallic industries	VAB	Gross aggregated value
DVIII	Metallic products, machinery and equipment	IMP	Taxes to the products, net subsides
DIX	Other manufacturing industries	GDP	Gross Domestic Product
GD4	Construction		

Table 5.4 Population scenarios

Year	Population			Population structure		Population growth rates		
	total	urban	rural	urban	rural	five years		ten years
						urban	rural	total
				%	%	%	%	%
1970	50 596 206	29 816 209	20 779 997	58.93	41.07	4.30	1.42	
1971	52 173 258	31 098 118	21 075 140	59.61	40.39			
1972	53 809 617	32 435 141	21 374 476	60.28	39.72			
1973	55 507 710	33 829 648	21 678 062	60.95	39.05			
1974	57 270 071	35 284 110	21 985 961	61.61	38.39			
1975	59 099 337	36 801 104	22 298 233	62.27	37.73	3.76	0.89	
1976	60 681 662	38 185 833	22 495 829	62.93	37.07			
1977	62 317 842	39 622 666	22 695 176	63.58	36.42			
1978	64 009 853	41 113 563	22 896 290	64.23	35.77			
1979	65 759 745	42 660 559	23 099 186	64.87	35.13			
1980	67 569 644	44 265 764	23 303 880	65.51	34.49	3.18	0.34	2.94
1981	69 055 786	45 672 986	23 382 800	66.14	33.86			
1982	70 586 932	47 124 945	23 461 987	66.76	33.24			
1983	72 164 504	48 623 062	23 541 442	67.38	32.62			
1984	73 789 971	50 168 804	23 621 167	67.99	32.01			
1985	75 464 847	51 763 686	23 701 161	68.59	31.41	2.81	0.05	
1986	76 932 837	53 219 611	23 713 226	69.18	30.82			
1987	78 441 783	54 716 486	23 725 297	69.75	30.25			
1988	79 992 836	56 255 462	23 737 374	70.33	29.67			
1989	81 587 182	57 837 724	23 749 458	70.89	29.11			
1990	83 226 037	59 464 490	23 761 547	71.45	28.55	2.38	0.40	2.11
1991	84 739 842	60 882 620	23 857 222	71.85	28.15			
1992	86 287 852	62 334 571	23 953 281	72.24	27.76			
1993	87 870 876	63 821 147	24 049 728	72.63	27.37			
1994	89 489 740	65 343 177	24 146 563	73.02	26.98			
1995	91 145 292	66 901 504	24 243 788	73.40	26.60	2.20	0.03	
1996	92 626 129	68 375 103	24 251 026	73.82	26.18			
1997	94 139 426	69 881 161	24 258 266	74.23	25.77			
1998	95 685 899	71 420 391	24 265 508	74.64	25.36			
1999	97 266 277	72 993 525	24 272 752	75.05	24.95			
2000	98 881 308	74 601 310	24 279 998	75.45	24.55	1.91	-0.11	1.74
2001	100 279 102	76 024 755	24 254 348	75.81	24.19			
2002	101 704 084	77 475 360	24 228 724	76.18	23.82			
2003	103 156 772	78 953 643	24 203 128	76.54	23.46			
2004	104 637 693	80 460 134	24 177 559	76.89	23.11			
2005	106 147 386	81 995 369	24 152 017	77.25	22.75	1.65	-0.20	
2006	107 450 553	83 346 823	24 103 730	77.57	22.43			
2007	108 776 091	84 720 552	24 055 539	77.89	22.11			
2008	110 124 367	86 116 922	24 007 445	78.20	21.80			
2009	111 495 755	87 536 308	23 959 447	78.51	21.49			
2010	112 890 633	88 979 088	23 911 545	78.82	21.18	1.43	-0.24	1.33
2011	114 110 767	90 255 516	23 855 252	79.09	20.91			
2012	115 349 345	91 550 254	23 799 091	79.37	20.63			
2013	116 606 628	92 863 565	23 743 063	79.64	20.36			
2014	117 882 883	94 195 717	23 687 167	79.91	20.09			
2015	119 178 380	95 546 978	23 631 402	80.17	19.83	1.24	-0.25	
2016	120 307 773	96 734 647	23 573 126	80.41	19.59			
2017	121 452 074	97 937 080	23 514 994	80.64	19.36			
2018	122 611 463	99 154 458	23 457 005	80.87	19.13			
2019	123 786 129	100 386 970	23 399 159	81.10	18.90			
2020	124 976 257	101 634 801	23 341 456	81.32	18.68	1.06	-0.26	1.02
2021	125 996 708	102 715 459	23 281 249	81.52	18.48			
2022	127 028 805	103 807 608	23 221 196	81.72	18.28			
2023	128 072 669	104 911 369	23 161 299	81.92	18.08			
2024	129 128 423	106 026 867	23 101 557	82.11	17.89			
2025	130 196 193	107 154 225	23 041 968	82.30	17.70			0.82

Emissions considered in these sub-sectors were CO_2, CH_4, N_2O, CO, NMVOC, NO_X, PM, and SO_2 These are taken into account in the model at the conversion node level for all fuels used to produce steam, heat and electricity (from cogeneration and self-generation). Due to the lack of information about actual processes, international standard efficiencies were used to represent conversion nodes in these sub-sectors.

This choice has been made considering the following criteria:

- The total fuel consumption;
- The natural gas consumption;
- The potential self-generation and co-generation development; and,
- The expected technological improvements that could lead to energy substitution.

In 1999 the five sub-sectors selected accounted for 50% of the total industrial fuel consumption and for 58% of the total industrial consumption of natural gas. In the same year almost 90% cogeneration and self-generation plants were located in these sub-sectors. We may also notice that iron and steel, glass, and cement sectors are the most technologically advanced in energy terms with good possibilities for fuel substitution and efficiency improvements.

In the cement sector (Figure 5.17) heat production is shifting from fuel oil consumption to alternative fuels such as used lubricants, used tires, etc. and some non-energy products and coke with important improvements in energy efficiency.

In the iron and steel sub-sector (Figure 5.18) we may notice more efficient electric furnaces that are being used since the nineties and the development of important cogeneration projects.

The case of the sugar sub-sector (Figure 5.19) is also relevant considering the high potential of biomass used for cogeneration and important needs of investments in order to improve energy efficiency.

The glass sub-sector (Figure 5.20) shows very efficient conversion processes that make the Mexican glass industry one of the most energy efficient industries in the world. This is also true in terms of quality and market penetration of its products that have contributed to the very successful expansion of this industry inside and outside the country providing this industry with significant net profits and financial soundness. Due to this situation energy efficiency and self-generation projects have been developed relatively more easily than in other sectors.

Table 4.5 Energy demand growth rates for the transformation and end use sectors

Intervalo	Oil and gas	Electric	Agriculture	Industrial	Transport	Commercial	Public and services	Residential
	%	%	%	%	%	%	%	%
1996-1997	3.39	6.45	5.50	1.11	4.24	4.18	1.05	-0.29
1997-1998	-4.74	6.16	2.60	0.85	3.24	6.10	1.50	2.88
1998-1999	16.28	5.58	6.38	-1.82	1.29	-24.60	4.86	-4.50
1999-2000	-0.01	6.57	-1.37	-5.97	4.06	9.00	7.91	3.14
2000-2001	-12.14	1.81	-0.23	-4.01	-2.87	-1.52	-2.29	1.25
2001-2002	-0.55	0.40	0.08	-1.00	0.35	0.24	1.35	1.25
2002-2003	1.15	3.73	1.33	2.92	3.55	3.37	2.91	1.26
2003-2004	3.49	4.72	1.09	4.04	5.83	4.17	3.61	1.30
2004-2005	3.66	5.34	3.16	4.72	6.38	4.02	4.16	1.26
2005-2006	3.60	5.52	0.55	4.91	7.12	4.37	4.50	1.06
2006-2007	3.40	4.55	0.51	3.53	5.33	4.59	3.76	1.09
2007-2008	3.27	4.76	5.43	3.48	6.17	3.98	3.96	1.15
2008-2009	3.49	5.15	3.05	5.06	8.33	3.65	3.88	1.10
2009-2010	3.75	5.30	3.63	5.47	8.18	3.77	4.09	1.11
2010-2011	3.62	4.92	3.20	5.17	7.77	3.38	4.05	0.95
2011-2012	2.47	3.92	2.34	3.11	4.71	3.09	3.09	0.97
2012-2013	2.57	4.01	2.46	3.24	4.71	3.03	3.09	0.96
2013-2014	2.77	4.08	2.59	3.30	4.77	2.96	3.09	0.98
2014-2015	2.80	4.17	2.70	3.37	4.80	2.90	3.09	0.98
2015-2016	2.84	4.24	2.82	3.44	4.83	2.84	3.09	0.84
2016-2017	2.88	4.30	2.92	3.48	4.84	2.79	3.08	0.85
2017-2018	2.91	4.36	3.03	3.52	4.85	2.73	3.08	0.91
2018-2019	2.95	4.41	3.13	3.58	4.86	2.68	3.08	0.92
2019-2020	2.98	4.45	3.22	3.60	4.86	2.63	3.07	0.92
2020-2021	3.01	4.48	3.31	3.63	4.86	2.59	3.07	0.78
2021-2022	3.04	4.51	3.39	3.66	4.85	2.54	3.07	0.78
2022-2023	3.07	4.53	3.47	3.68	4.84	2.50	3.07	0.79
2023-2024	3.10	4.56	3.54	3.70	4.83	2.46	3.07	0.79
2024-2025	3.12	4.57	3.61	3.72	4.82	2.42	3.07	0.79

Table 4.6 Energy demand growth rates for the end use industrial sub-sectors

	Petrochemical	Iron and	Chemicals	Sugar	Cement	Mining	Paper andsevices	Glass	Fertilizers
	%	%	%	%	%	%	%	%	%
1996-1997	-6.08	4.56	5.30	6.37	-0.89	-5.62	-10.04	11.56	-13.95
1997-1998	-8.53	-0.12	3.63	6.08	8.99	7.76	9.27	0.30	-14.96
1998-1999	-25.16	-1.82	-3.60	-10.61	-8.30	-4.02	-0.72	-6.43	11.60
1999-2000	-9.15	6.51	10.62	-9.89	12.31	3.59	-12.52	8.36	-15.56
2000-2001	-1.35	-8.81	-6.38	1.05	-11.03	-5.49	-5.74	-12.36	-15.48
2001-2002	-1.24	-2.58	-1.21	1.40	0.55	0.28	-6.78	1.21	-4.24
2002-2003	1.68	5.16	2.18	1.55	4.40	0.94	-1.24	5.36	0.42
2003-2004	2.25	5.25	3.23	1.87	7.46	1.94	-0.39	7.13	3.09
2004-2005	3.14	5.64	4.14	2.80	7.87	2.57	0.15	7.71	3.22
2005-2006	3.01	5.38	4.11	3.66	7.21	2.19	1.58	7.19	3.53
2006-2007	2.37	4.07	3.37	2.97	4.99	2.75	0.91	5.07	2.75
2007-2008	1.82	3.82	2.98	3.14	4.81	2.68	0.74	4.96	2.08
2008-2009	2.73	6.15	4.04	3.09	8.49	2.67	0.90	8.69	2.87
2009-2010	3.01	6.24	4.27	3.20	9.54	3.00	0.37	9.77	3.68
2010-2011	2.88	5.82	4.08	2.81	9.27	3.12	0.26	9.51	3.46
2011-2012	1.76	3.27	2.88	2.36	4.42	2.17	1.43	4.65	2.24
2012-2013	1.85	3.37	2.91	2.34	4.56	2.23	1.58	4.78	2.26
2013-2014	1.94	3.46	2.78	2.33	4.69	2.29	1.69	4.89	2.29
2014-2015	2.03	3.55	2.80	2.31	4.79	2.33	1.76	4.98	2.30
2015-2016	2.11	3.62	2.98	2.29	4.88	2.38	1.81	5.05	2.85
2016-2017	2.18	3.70	3.00	2.28	4.96	2.42	1.83	5.11	2.74
2017-2018	2.25	3.76	3.02	2.26	5.02	2.46	1.84	5.15	2.75
2018-2019	2.31	3.82	3.04	2.47	5.07	2.50	1.84	5.19	2.78
2019-2020	2.37	3.88	3.06	2.34	5.11	2.53	1.82	5.21	2.66
2020-2021	2.43	3.93	3.08	2.33	5.14	2.57	1.80	5.23	2.81
2021-2022	2.49	3.97	3.10	2.31	5.17	2.60	1.78	5.24	2.69
2022-2023	2.54	4.01	3.11	2.30	5.18	2.63	1.75	5.25	2.84
2023-2024	2.58	4.04	3.13	2.29	5.19	2.66	1.72	5.25	2.73
2024-2025	2.63	4.07	3.15	2.28	5.20	2.69	1.69	5.30	2.87

Table 4.7 Energy demand growth rates for the end use industrial sub-sectors

	Malt and beer	Bottled water	Construction	Automotive	Rubber	Aluminum	Tobacco	Other
	%	%	%	%	%	%	%	%
1996-1997	4.88	5.57	1.60	11.00	13.12	27.40	10.40	5.81
1997-1998	10.65	6.08	4.52	8.36	7.63	-8.65	9.91	4.01
1998-1999	-1.34	10.83	8.78	24.94	-5.72	-5.64	-3.43	23.75
1999-2000	6.68	6.61	6.88	-12.31	5.09	-4.11	-23.61	-19.89
2000-2001	-1.19	-1.86	-4.50	-1.11	-4.29	1.86	5.86	0.11
2001-2002	0.49	0.13	3.30	1.21	1.08	-4.25	0.67	-0.85
2002-2003	1.57	1.69	5.90	6.53	3.76	2.70	1.52	3.13
2003-2004	2.00	1.30	6.98	8.04	4.11	5.00	2.33	4.90
2004-2005	2.94	2.49	7.58	8.39	4.55	5.64	3.28	5.48
2005-2006	3.71	3.78	7.93	9.02	4.03	5.34	4.24	6.14
2006-2007	3.04	3.13	4.25	6.38	3.25	3.99	3.47	3.77
2007-2008	3.20	3.37	5.54	6.10	2.67	3.71	3.60	4.19
2008-2009	3.15	3.41	9.06	8.11	3.55	6.02	3.56	5.90
2009-2010	3.48	3.61	9.38	8.29	3.81	6.10	3.59	6.43
2010-2011	2.28	3.14	8.90	7.17	3.66	5.68	3.17	5.92
2011-2012	2.60	2.73	4.34	4.53	2.51	3.12	2.71	3.59
2012-2013	2.58	2.69	4.48	4.49	2.59	3.22	2.71	3.82
2013-2014	2.56	2.66	4.59	4.45	2.66	3.31	2.64	3.88
2014-2015	2.55	2.64	4.62	4.84	2.73	3.40	2.57	3.91
2015-2016	2.53	2.62	4.86	4.76	2.80	3.47	2.57	3.94
2016-2017	2.52	2.57	4.76	4.77	2.85	3.87	2.57	3.95
2017-2018	2.50	2.55	4.86	4.73	2.90	3.94	2.57	3.95
2018-2019	2.49	2.53	4.96	4.70	2.94	3.99	2.50	3.96
2019-2020	2.47	2.51	4.93	4.67	2.99	4.05	2.50	3.96
2020-2021	2.46	2.50	4.89	4.63	3.02	4.10	2.44	3.96
2021-2022	2.45	2.48	4.96	4.60	3.05	4.14	2.44	3.96
2022-2023	2.44	2.46	4.86	4.57	3.08	4.18	2.43	3.96
2023-2024	2.42	2.44	4.95	4.54	3.11	4.21	2.43	3.95
2024-2025	2.41	2.43	4.95	4.51	3.12	4.25	2.42	3.95

Table 5.8 Energy demand growth rates for the end use transport sub-sectors

	Road	Air	Rail	Sea	Electric
	%	%	%	%	%
1996-1997	3.75	7.49	15.11	7.21	0.48
1997-1998	2.69	10.10	-16.56	26.26	0.24
1998-1999	-0.12	5.59	-5.98	49.65	1.19
1999-2000	4.09	0.46	2.21	12.42	5.66
2000-2001	- 0.64	-1.00	0.20	-63.30	-13.26
2001-2002	0.45	1.38	1.21	-12.36	-4.64
2002-2003	3.78	3.53	3.58	-14.05	-0.14
2003-2004	5.95	5.99	5.30	-4.60	2.46
2004-2005	6.44	6.39	6.08	0.01	5.71
2005-2006	7.13	7.18	7.06	6.70	6.51
2006-2007	5.37	5.39	5.13	1.26	5.22
2007-2008	6.18	6.23	6.07	5.74	5.86
2008-2009	8.35	8.35	8.16	6.96	7.96
2009-2010	8.17	8.23	8.16	8.00	7.85
2010-2011	7.76	7.81	7.73	8.26	7.41
2011-2012	4.71	4.75	4.63	4.56	4.38
2012-2013	4.70	4.78	4.67	4.62	4.40
2013-2014	4.76	4.81	4.78	4.77	4.42
2014-2015	4.80	4.82	4.69	4.70	4.64
2015-2016	4.83	4.84	4.72	4.69	4.65
2016-2017	4.84	4.85	4.77	4.80	4.66
2017-2018	4.85	4.86	4.81	4.82	4.66
2018-2019	4.86	4.86	4.83	4.80	4.67
2019-2020	4.86	4.86	4.84	4.82	4.67
2020-2021	4.86	4.86	4.85	4.81	4.76
2021-2022	4.85	4.85	4.85	4.78	4.76
2022-2023	4.84	4.84	4.84	4.82	4.74
2023-2024	4.83	4.83	4.83	4.83	4.74
2024-2025	4.82	4.82	4.82	4.81	4.72

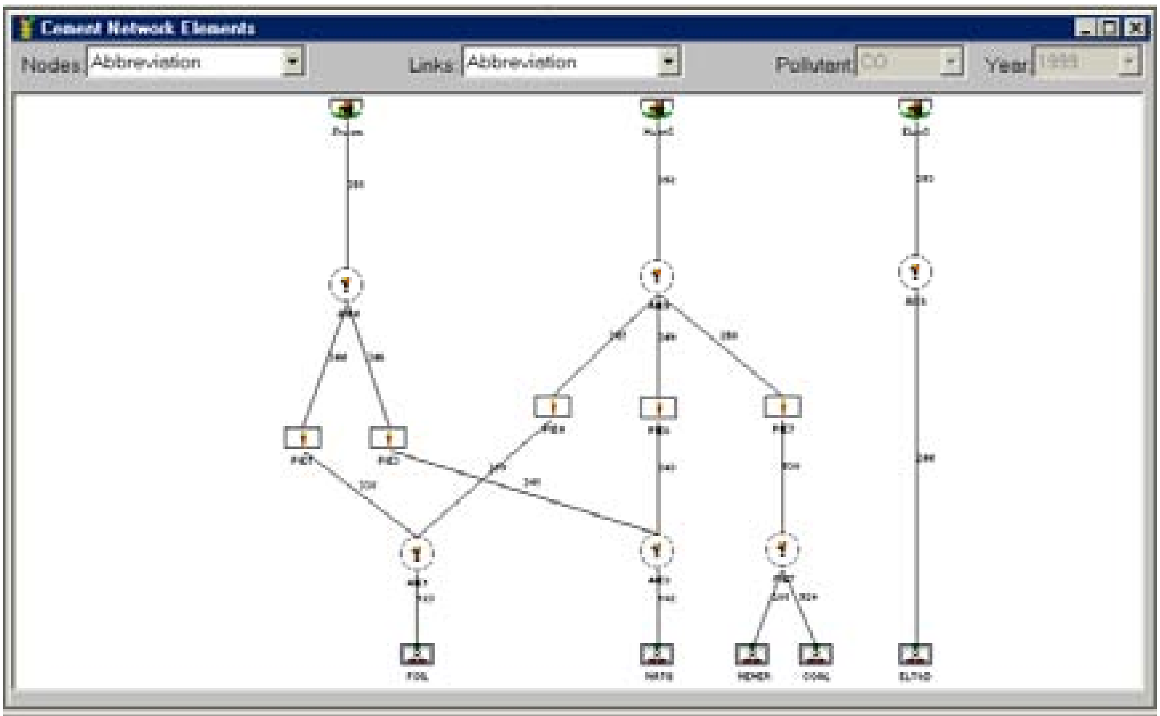

Figure 5.17 Cement sub-sector network.

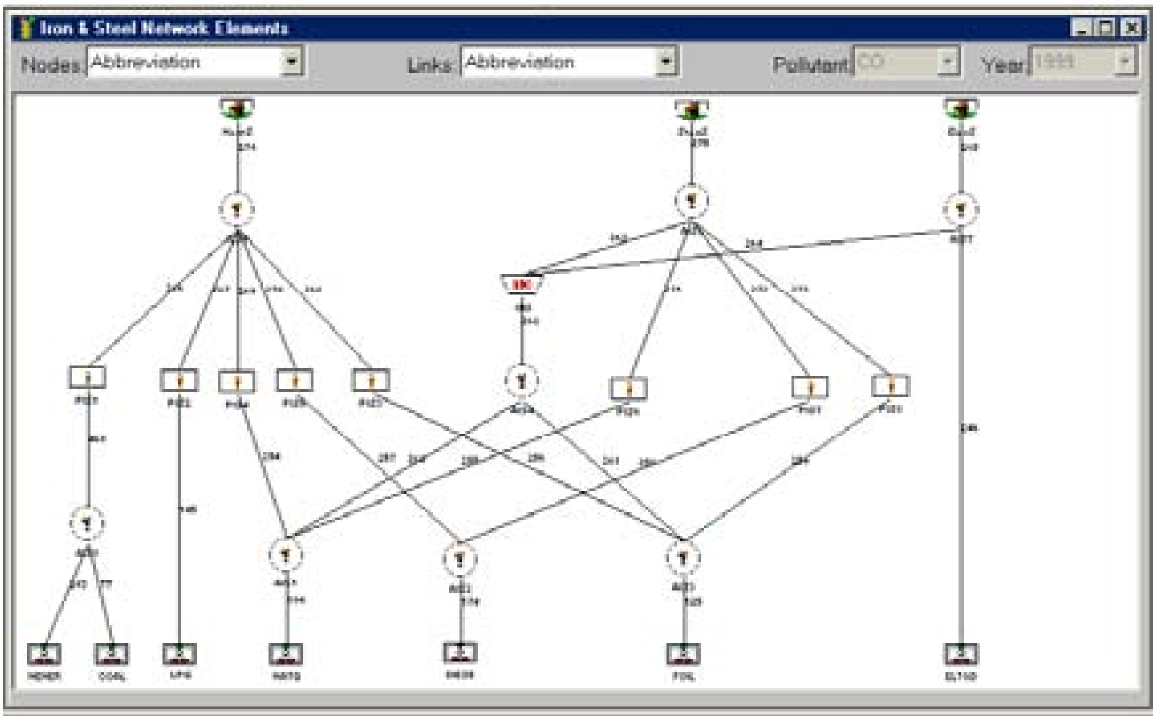

Figure 5.18 Iron and steel sub-sector network.

The choice of PEMEX Petrochemical sub-sector (Figure 5.21) considered its high level of fuel consumption. While natural gas consumption for energy and non-energy purposes in this sub-sector represents 31% of the total natural gas consumption in the industrial sector, sector's gasoline consumption, as a raw material, represents the total consumption of gasoline in the industrial sector. In the same way all the electricity needs of PEMEX Petrochemical are covered trough co-generation and self-generation, which represents 73% of the total electricity produced in the industrial sector in 1999. According to the last prospective study for the Mexican power sector[23], co-generation potential in this sub-sector accounts for at least 1,060 MW which would allow PEMEX Petrochemical to sell excess capacity to the grid. It is also important to note the significant consumption of LPG, kerosene and other non-energy products as raw materials in this sub-sector.

The remaining industrial sub-sectors are represented by final fuel consumption without possibility of substitution between them or to take into account efficiency improvements. Emissions in these sub-sectors are taken into account in the model at the final demand level introducing IPCC emission factors for every fuel consumed in the different sub-sectors. (chemicals, malt and beer, automotive, paper and cellulose, rubber, tobacco, aluminum, bottled waters, fertilizers, mining and others)

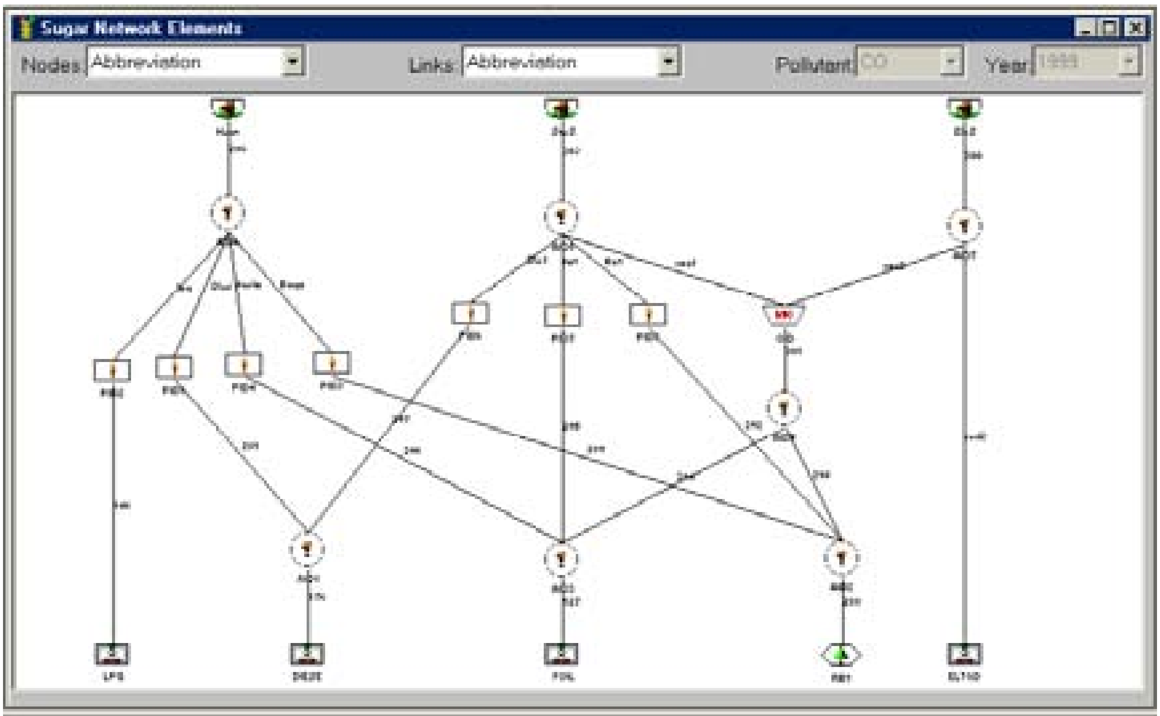

Figure 5.19 Sugar sub-sector network.

Among these sub-sectors the more representative one is the Others sub-sector (Figure 5.22), which shows clearly how final fuel consumptions are represented in the model and how further developments of the network with more detailed information are needed in order to represent possibilities of fuel substitution and to take into account efficiency improvements.

[23] Prospectiva del Sector Eléctrico 2002-2011, SENER, México, 2002.

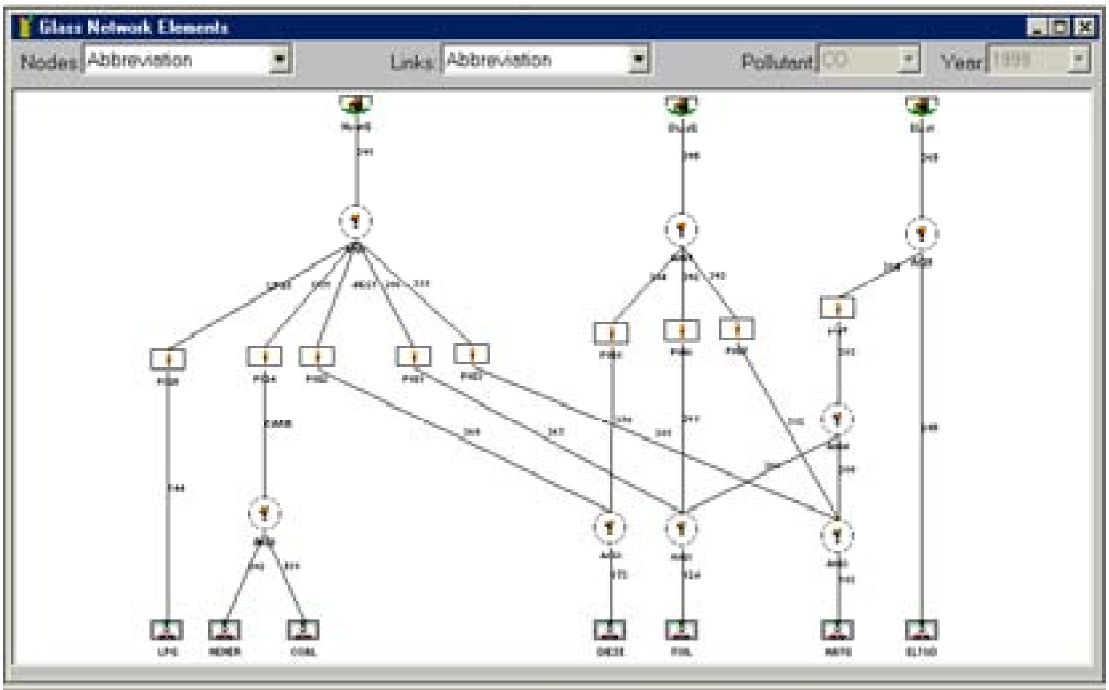

Figure 5.20 Glass sub-sector network.

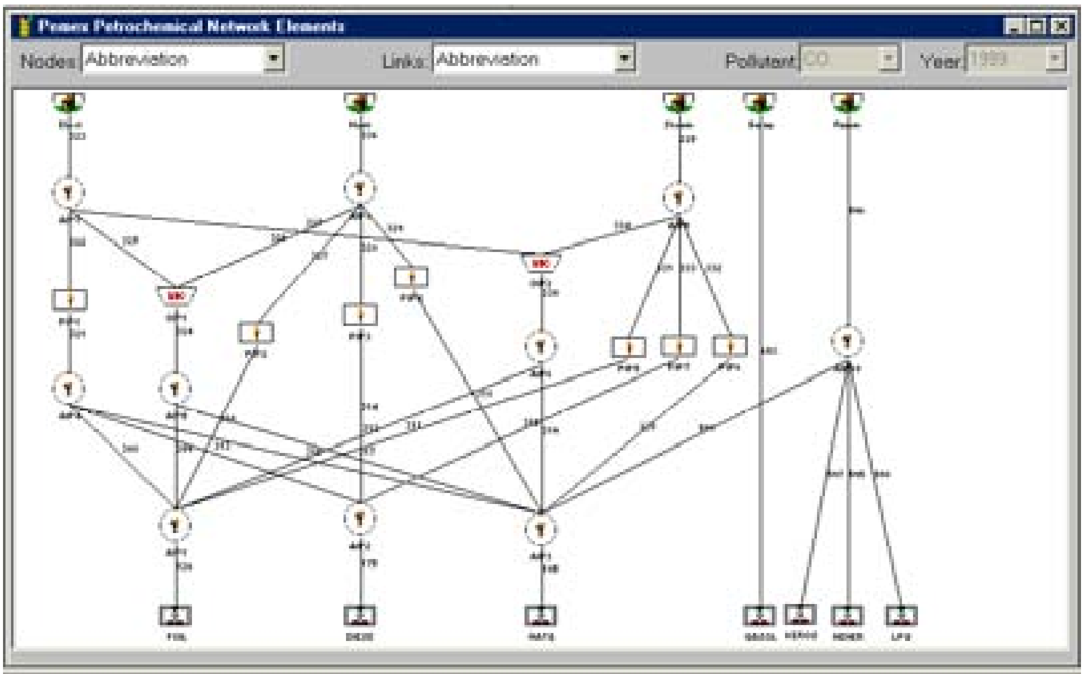

Figure 5.21 PEMEX petrochemicals network.

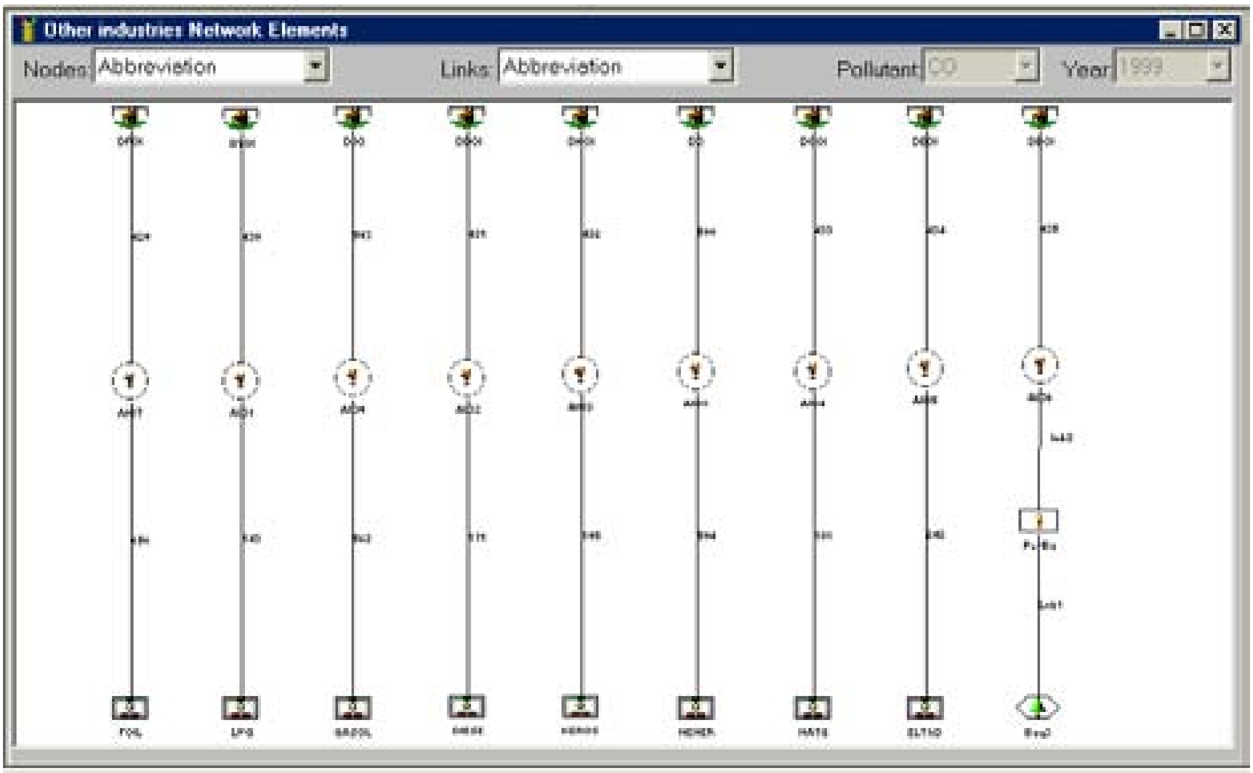

Figure 5.22 Other industries sub-sector network.

5.3.2. Residential demand sector

The residential sector (Figure 5.23) uses electricity and kerosene for lighting, air conditioning and a small amount for cooking, and it uses LPG, natural gas and firewood for cooking and water heating. It also uses a very small amount of solar energy for lighting in rural areas. There exist two types of fuel substitution group: [LPG ↔ natural gas ↔ solar ↔firewood][24] and [electricity ↔ solar ↔ kerosene]. For a detailed analysis of the solar energy option for water heating in the residential and commercial sectors we refer the reader to the study carried out by the Quintanilla, *et al.* (Quintanilla, 2000) for the World Bank.

[24] The symbol ↔ indicates competition; for example [LPG ↔ natural gas ↔ wood] indicates that LPG, natural gas, and wood compete against each other for a share of the market.

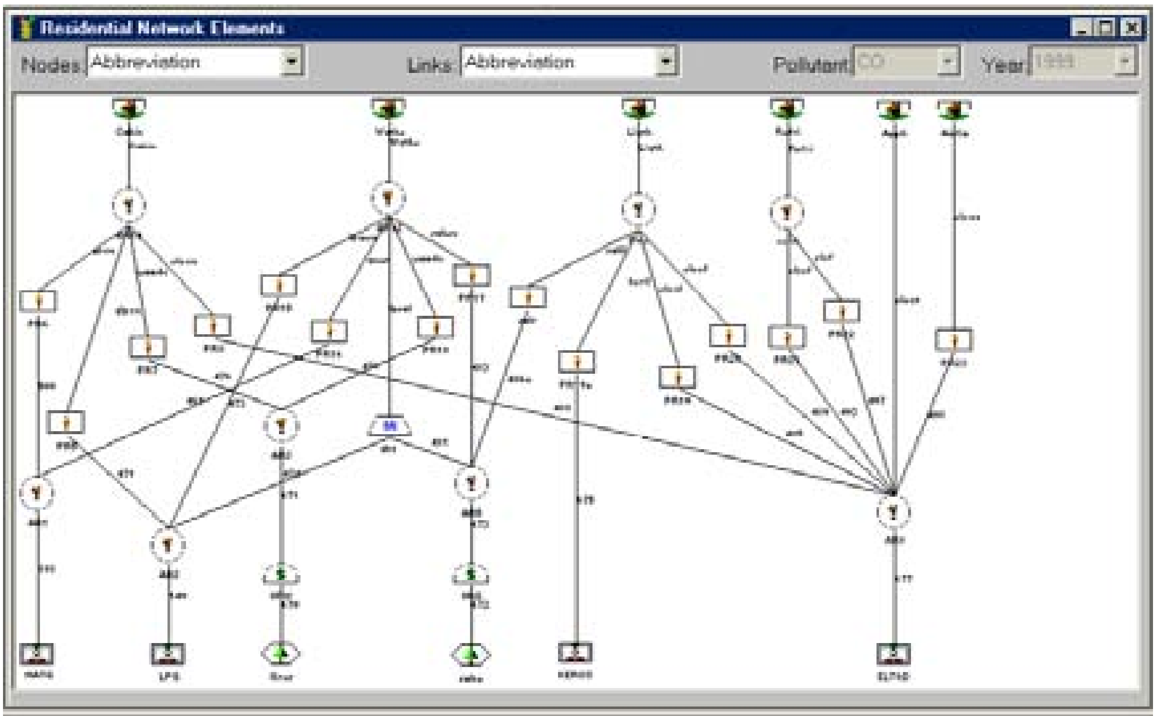

Figure 5.23 Residential sector network.

In this sector, energy use must be provided in a residential housing unit basis. A database called HOUD, based on the data the Mexican Energy Secretariat introduced in the BRUSII model, was consulted for this purpose and the following data extracted:

- Number of households;
- Appliance utilization; and,
- Fuel types.

The HOUD database provides energy consumption and household expenditures for:

- Natural gas;
- Electricity;
- Firewood;
- LPG; and,
- Kerosene.

The energy demand growth rates for the residential sector are shown in Table 5.5. The exception to these energy demand growth rates were the growth rates for electrical appliances and air conditioning. In the case of electrical appliances these values were kept constant after the first two years and after the first four years in the case of air conditioning.

5.3.3. Transport demand sector

For the transport sector (Figure 5.24), fuel demand was divided into the following categories: rail, sea, air, road and electric. Rail transport use diesel, sea and water transport can use fuel oil or diesel, air transport use jet fuel and kerosene. Road transport uses diesel, gasoline, LPG and natural gas. Transport sector constitutes the major energy-demanding sector in the Mexican energy system, it accounts for the 39% of total energy consumption.

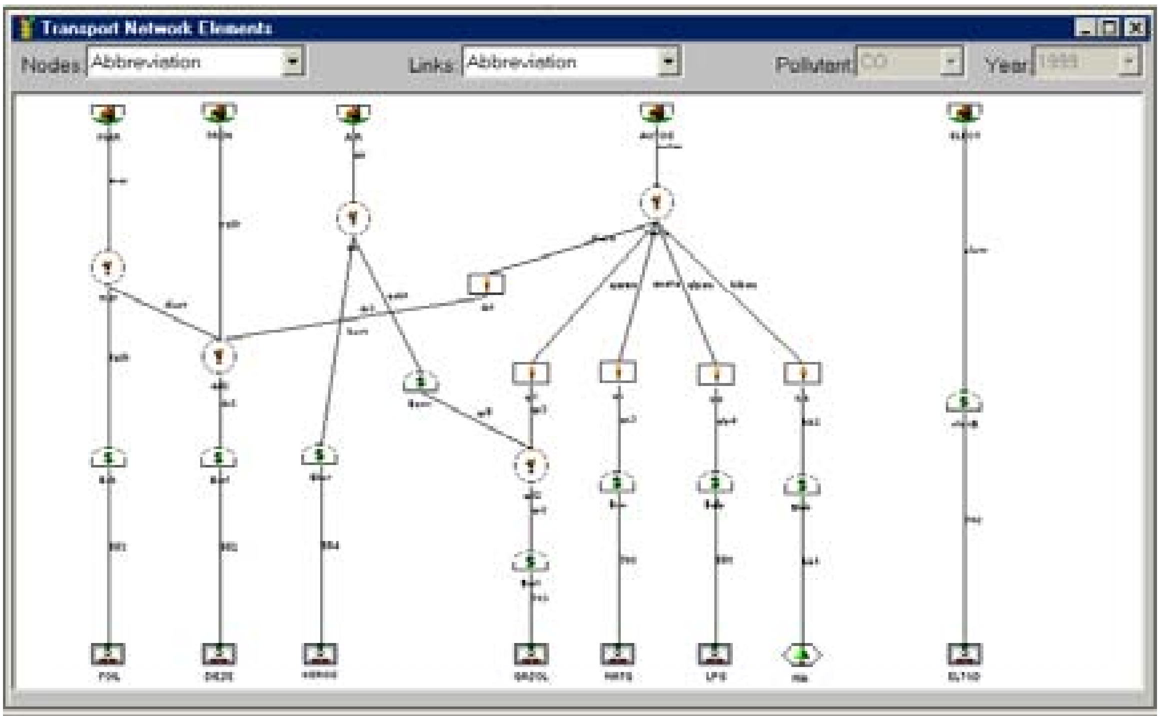

Figure 5.24 Transport sector network.

The transportation sector is fundamentally different to other demand sectors since it represents as a part of service sector. Transportation is used to support other activities in the industrial, commercial and residential sector. Lack of official Mexican data has meant that other resources must be used. The TRAN database (MAR, 2001) was used with a splitting in terms of transport mode, average distance traveled, technology, passenger and freight, number of vehicles. Changes in energy consumption can occur due to efficiency, technological and economic reasons. Because of this, trend scenarios were considered in a business-as-usual fashion where no major differences with the past trends occur, *i.e.,* energy demand growth rates for individual transport modes conduct to the same total demand growth rates provided by MODEMA. Hybrid transport alternative refers to the vehicles that use hydrogen and electricity. The electricity is generated by renewable energy sources such as solar and wind. There are two types of fuel substitution group in the rod transportation mode: [natural gas and hybrid ↔ gasoline][25] and [LPG ↔ diesel].

5.3.4. Commercial and public demand sector

The commercial and public sector network is shown in Figure 5.25. The fuel mix in the commercial sector has changed significantly over the 1989–1999 period. In 1989 fuel oil

[25] The symbol ↔ indicates competition; for example [LPG ↔ natural gas ↔ wood] indicates that LPG, natural gas, and wood compete against each other for a share of the market.

accounted for 46.9% of the commercial sector energy consumption, but a drastic reduction in its consumption in 1999 caused it to disappear from this sector's consumption. LPG was the substitute fuel and its demand has increased by 623% over the period 1989–1999. Electricity remained an important energy source in this period accounting for 38.8 % of the total energy consumed in 1989 and 39.6% in 1999. Consumption of diesel represented 1.7% of total energy consumed in 1989 and 3.5% in 1999.

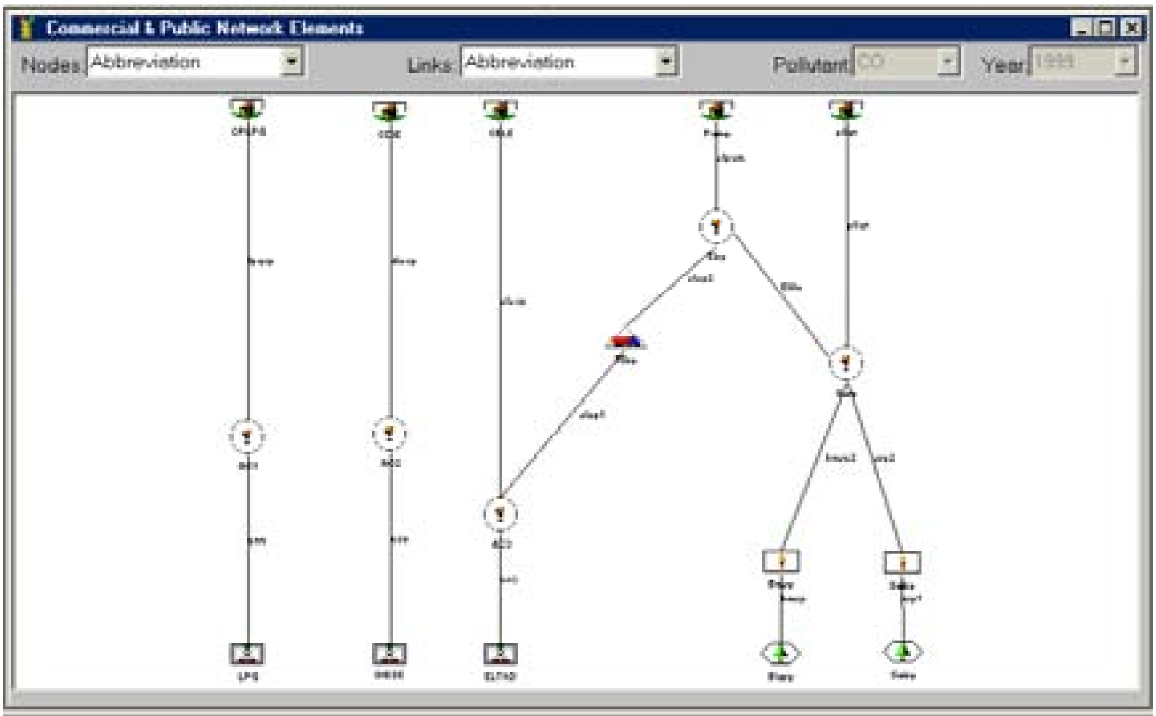

Figure 5.25 Commercial and public sector network.

Energy consumption in the public sector accounted for 0.5% of total end-user energy demand in 1989 and 1999. Energy use in the public sector is defined as the energy consumed by public illumination and public water pumping. Energy data includes only electricity used, 15.9 PJ in 1989 and 19.5 PJ in 1999, representing an annual rate of growth of 2.1%. The consumption for this sector is expected to grow annually 3.2%. The energy consumption only includes electricity, its generation is carried out through alternative energy sources such as solar and biomass and they compete with grid electricity.

5.3.5. Agriculture demand sector

The majority of energy consumed in the agriculture sector corresponded to diesel, which accounted for 58.6% of total energy consumed in 1989 and 68.1% in 1999. Between 1989 and 1999, kerosene consumption fell at an annual rate of 42.1%, while LPG consumption increased by 19.4% annually, still a marginal consumption of 8.5 PJ in 1999. Electricity consumption remained constant in this period, with 26 PJ in 1989 and 28.8 PJ in 1999.

Figure 5.26 shows the configuration of present agriculture sector network. The exception is that the network includes some nodes for the inclusion of renewable energies in the sector. For the alternative scenario in introducing more renewable energy, there will be a competition between grid electricity and electricity generated by solar, wind and biomass at the local area.

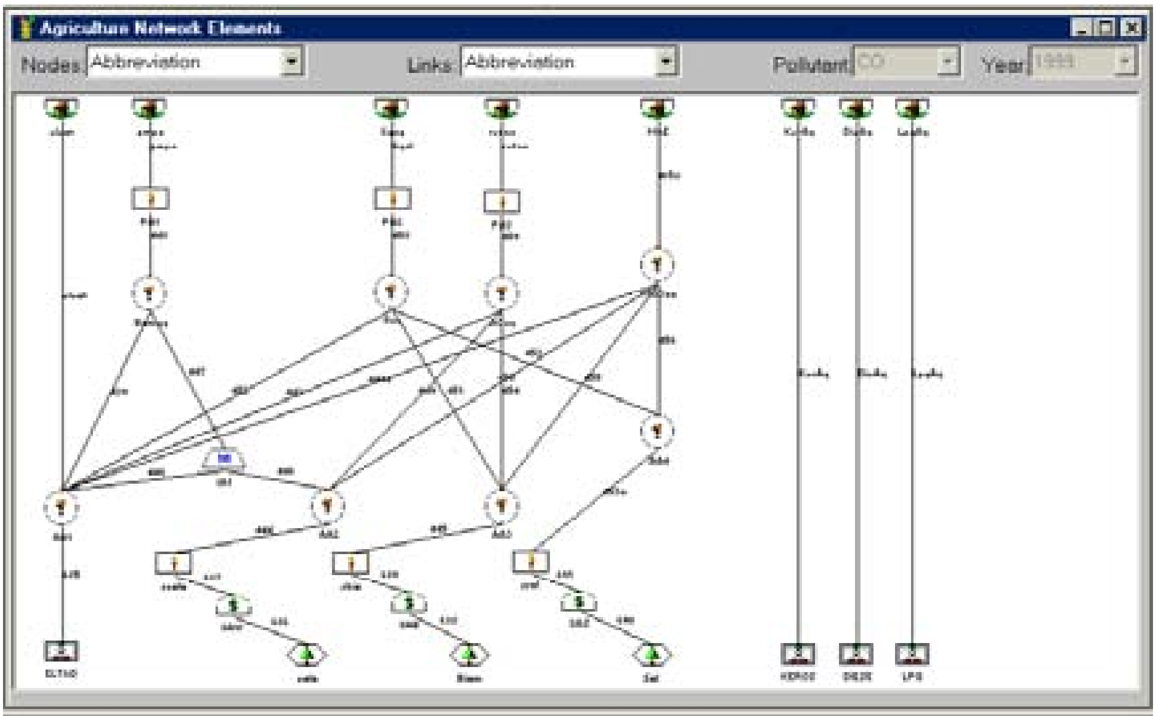

Figure 5.26 Agriculture sector network.

6. COMPARATIVE ASSESSMENT ANALYSIS OF ENERGY OPTIONS AND STRATEGIES UP TO 2025

According to Chapter 5, section 5.1, a reference case (unlimited natural gas supply) and three alternative scenarios (nuclear, limited natural gas and renewables energy scenarios) will be considered in the study.

6.1. Reference case results

6.1.1. Primary energy supply

Primary energy supply will increase from 9,312.3 PJ (1999) to 13,126.5 PJ (2025). Crude oil market share decrease from 68.2% in 1999 to 62.7% in 2025, as a consequence of the non-associated gas growth share in 11.9% in 2025 (compared with 4.5% in 1999) meanwhile associated gas decrease from 13.9% in 1999 to 12.8% in 2025 as shown in Table 6.1 and Figure 6.1. Non-associated gas growth rate is the highest (5.2%) followed by coal (3.7%), crude oil (1.0%), geothermal (0.8%) and sugar cane (0.2%). It is important to take in to account that first unit of Laguna Verde nuclear power plant will be closed in 2025.

Table 6.1 Total primary energy supply (Reference case)

	1999 PJ	2000 PJ	2005 PJ	2010 PJ	2015 PJ	2020 PJ	2025 PJ
Crude oil	6 351.86	6 567.30	7 609.60	7 795.85	7 958.46	8 102.63	8 231.89
Associated gas (includes flaring)	1 294.55	1 338.46	1 550.88	1 512.61	1 621.98	1 651.37	1 677.71
Non associated gas	422.17	445.98	873.78	1 390.85	1 364.24	1 477.55	1 567.55
Condensates	124.92	124.92	124.92	124.92	124.92	124.92	124.92
Coal	272.80	298.01	367.10	441.67	515.09	598.55	705.39
Sugar cane bagasse	91.98	90.90	91.48	92.91	94.37	96.03	98.05
Firewood	251.90	251.90	251.90	251.90	251.90	251.90	251.90
Nuclear	108.26	107.57	107.57	107.57	107.57	107.57	53.79
Hydro	336.04	341.67	313.54	346.12	346.12	346.12	346.12
Geothermal	57.78	67.46	74.97	74.97	71.87	71.87	71.87
Wind	0.06	0.52	0.52	0.52	0.52	0.52	0.52
Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**9 312.31**	**9 634.69**	**11 366.28**	**12 139.89**	**12 457.03**	**12 829.03**	**13 129.70**

6.1.2. Oil and gas sector

Mexico is a producer and an important exporter of crude oil, however, is an importer of refined oil products. Oil production in 1999 amounted to 6,352 PJ and it is projected that in

2025 will be of 8,232 PJ as shown in Table 5.2. That means a growth rate of 1.0% and the market share drop from 68.2% to 62.7%.

The assumptions under which this oil production are projected were: 1) country's total refining capacity is set to 1.565 million barrels per day and no capacity additions along the entire projection period, 2) the driving oil product is gasoline, 3) maquila's mechanism capacity is set to the maximum capacity of the current agreements, 4) excess demand of gasoline, after domestic refining and maquila's contribution, are satisfied through imports and 5) oil exports will increase at a decreasing growth rate, from 6.94% from 1999 to 2000 up to 0.55% from 2024 to 2025.

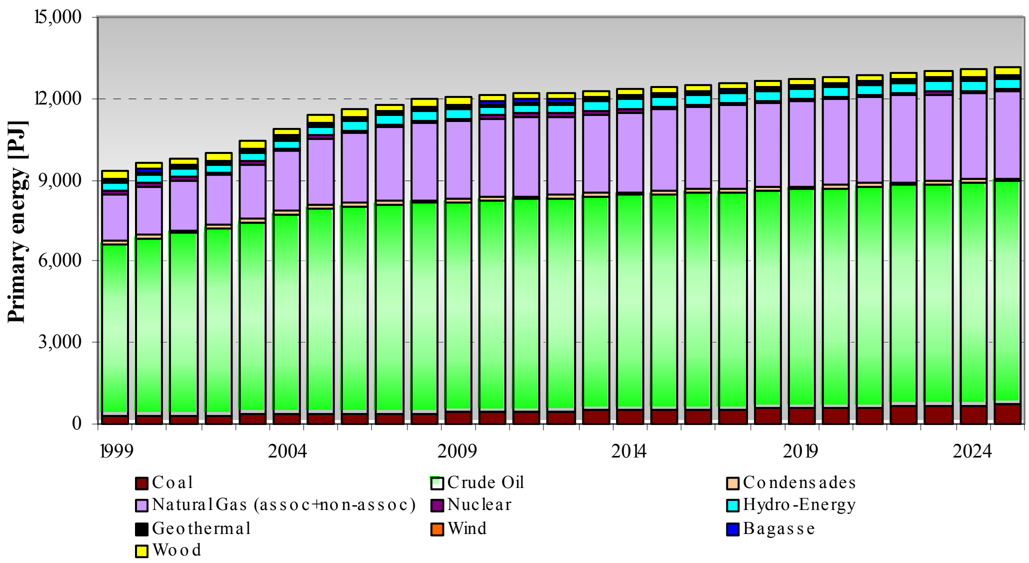

Figure 6.1 Total primary energy supply (Reference case).

Figure 6.2 shows the projected oil production in barrels per day. If the projected increase in the refining capacity (the addition, to the existing capacity, of 160,000 barrels per day by the year 2006) becomes on line this will reduce the amount of crude oil sent to maquila for some time, however, it would not represent a reduction in the oil production. On the other hand, the behavior of the crude oil exports will have a direct impact on the oil production and will depend, directly, on the crude oil exports policy and economic considerations. Also, changes in the economic and population scenarios, considered in the present study, will have, to some extent, an impact on the results for the projected oil production.

The gasoline and diesel imports, have become an essential component to provide domestic market, fact that forces to the refinement industry to become strong in order that in a modern and flexible form be able to face the challenges of a dynamic internal market. In 1999, after self-consumption the gasoline yielding of the SNR was 25.34%. Under these yielding conditions the existing refining capacity (1.525 million barrels per day of atmospheric distillation) was not enough to satisfy the required gasoline production from the country's refineries.

Table 6.2 Oil and gas sector (Reference case)

	1999	2000	2005	2010	2015	2020	2025
	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Crude oil	6 351.86	6 567.30	7 609.60	7 795.85	7 958.46	8 102.63	8 231.89
Condensates	124.92	124.92	124.92	124.92	124.92	124.92	124.92
Associated gas (includes flaring)	1 294.55	1 338.46	1 550.88	1 512.61	1 621.98	1 651.37	1 677.71
Non-associated gas	422.17	445.98	873.78	1 390.85	1 364.24	1 477.55	1 567.55
Natural gas imports	59.87	231.38	550.54	620.67	1 193.52	1 808.65	2 689.81
Total	8 253.37	8 708.02	10 709.73	11 444.90	12 263.12	13 165.12	14 291.87
Total natural gas	1 776.59	2 015.81	2 975.21	3 524.13	4 179.74	4 937.57	5 935.07
	1999	**2000**	**2005**	**2010**	**2015**	**2020**	**2025**
Crude oil (million barrels per day)	2.91	3.00	3.49	3.58	3.65	3.72	3.78
Condensates (thousand barrels per day)	93.48	93.48	92.87	92.87	92.87	92.87	92.87
Associated gas (includes flaring; million cf per day)	3 133.47	3 215.53	3 710.39	3 618.82	3 880.50	3 950.79	4 013.82
Non-associated gas (million cf per day)	1 264.90	1 334.83	2 580.45	4 107.45	4 028.85	4 363.49	4 629.27
Natural gas imports (million cf per day)	168.50	649.29	1 570.68	1 770.74	3 405.07	5 160.02	7 673.92

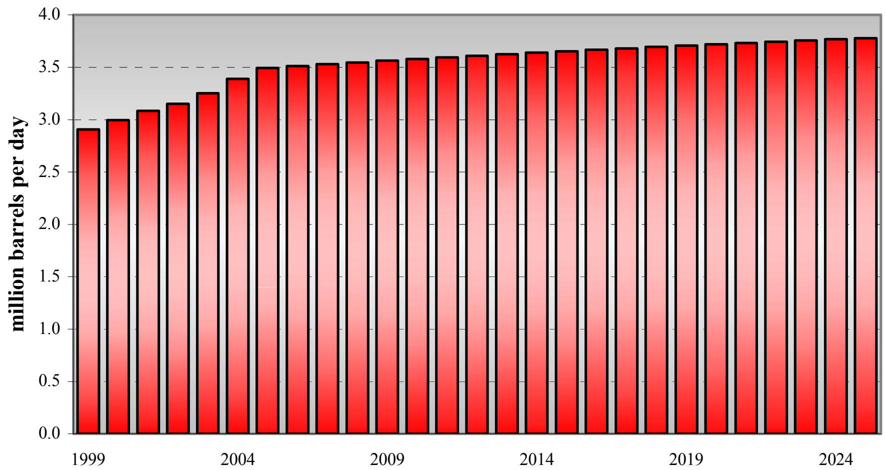

Figure 6.2 Projected crude oil production (Reference case).

By year 2006, is expected to have a new refinery with a capacity of 160,000 barrels per day plus the additions from the phases in progress of the reconfiguration program and a gasoline yielding of 32.8%, the total refining capacity will be 1.715 million barrels per day. Under these conditions there will be a deficit of refining capacity of 27,000 barrels per day. This deficit could be covered by a reduction in the gasoline exports; however such action will have impact on the route of the aggregated value for the oil resource. For year 2008 and the rest of the projection period, after the completion of the reconfiguration program and with a gasoline yielding of 39%, the total refining capacity will have to increase to the following total capacities: 1.943 million barrels per day for 2008; 2.480 million barrels per day for 2015; 3.157 million barrels per day for 2020; 4.070 million barrels per day for 2025. Therefore, the accumulated increase capacity along the projection period will be 2.355 million barrels per day. The elimination of the gasoline exports will have the effect to lower the required capacity, by 2025, to 2.1 million barrels per day. The penetration of other fuels, in substitution of gasoline, will, also, have the effect to reduce the required refining capacity.

With respect to natural gas, Table 5.2 and Figure 5.3 show that total natural gas supply grows from 1,776.6 PJ in 1999 to 5,935.1 PJ in 2025. This means a growth rate of 4.8%, led especially by the imports that arise from 59.9 PJ to 2,689.8 PJ in the same period and its market share will be of 45.3% in 2025 for total gas supply, upper from 3.4% in 1999.

As in the case of oil production, the projections of natural gas production were developed under some assumptions, namely: 1) total capacity of gas plants is fix and equal to 5,034 million cubic feet per day, 2) total capacity of fractionating plants is also fix and equal to 554 million cubic feet per day, 3) natural gas exports are marginal with a decreasing pattern and 4) no capacity additions for gas and fractionating plants along the entire projection period. Additionally, the ratio crude oil to associated gas is kept constant and equal to the average value of the last few years.

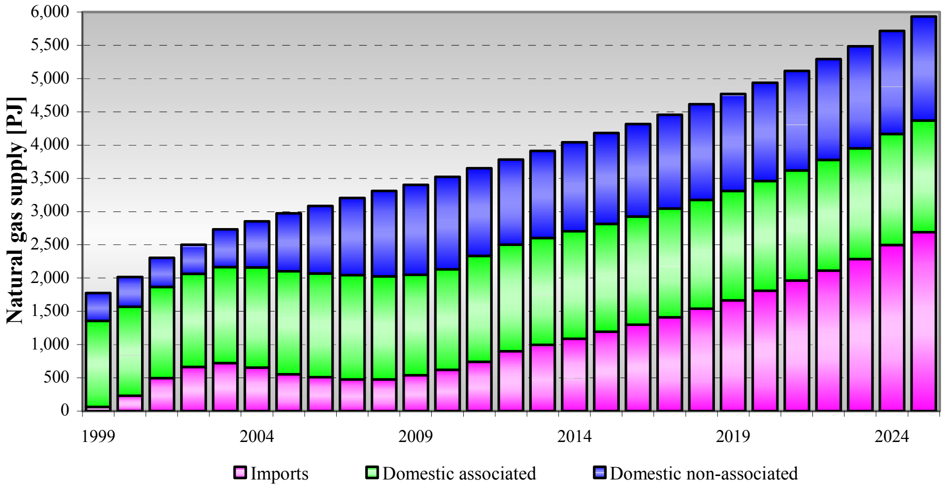

Figure6.3 Natural gas supply (Reference case)

According to mentioned publication, under the scenario of accelerated development of the natural gas potential, the domestic natural gas production for the period 2002-2011 could be, in average, 7,096 million cubic feet per day with a maximum of 9,000 million cubic feet by the end of 2010. Therefore, if this program of investments comes into reality, the entire picture (Figure 6.4), in terms of the split of domestic production and imports will change, passing from a natural gas importer to an exporter.

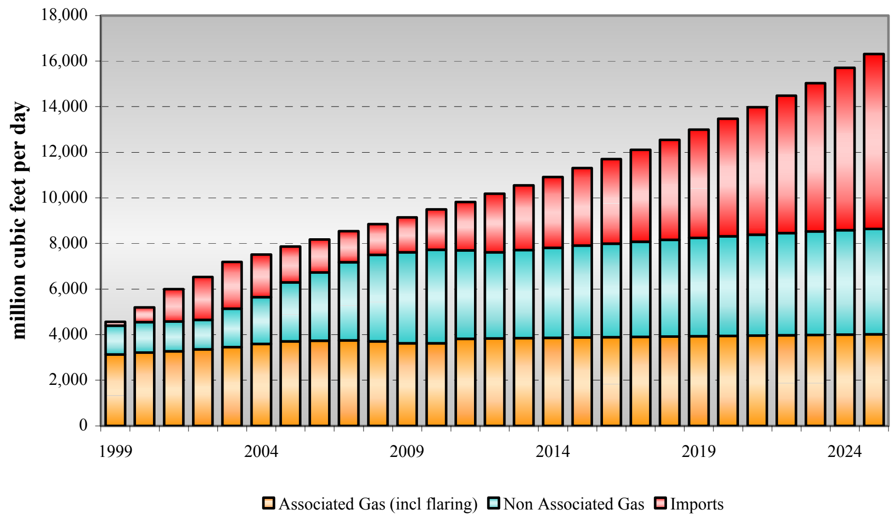

Figure 6.4 Projected natural gas supply (Reference case).

6.1.3. Electricity supply

As BALANCE does not perform a system expansion, in a typical ENPEP application, the expansion plan is determined by DECADES and then transferred to BALANCE. Using the BALANCE dispatch node and the thermal- and hydro-unit nodes (Figure 6.5), BALANCE then dispatches the system unit-by-unit, and calculates unit-level generation, fuel consumption, and production cost for all existing and new units.

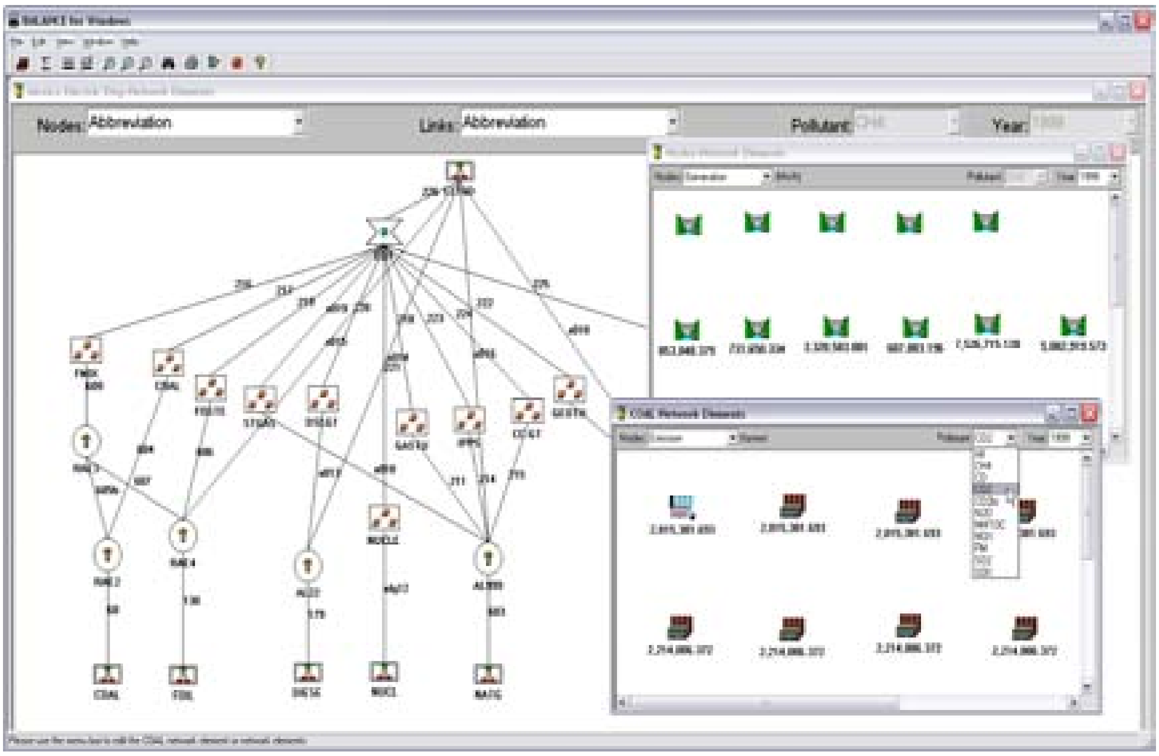

Figure 6.5 Electricity dispatch network.

For the reference case the power generation by fuel type and its share are shown in Figure 6.6. This case corresponds to the actual natural gas policy in the power sector. For the reference case — no limitation in the natural gas supply — the main results for the power sector are as follows:

- The natural gas-fired generation increases from 49.92 to 1,265.18 PJ (out of 1,602.72 PJ total) in 2025; natural gas generation share increases from 8.09 to 78.94 percent;
- Fuel oil fired generation decreases from 332.79 to 39.39 PJ in 2025; its share in the total generation decreases from 53.93 to 2.46 percent as a result of the fuel oil reduction policy in the country and the conversion from fuel oil to imported coal of the dual power plants, therefore, coal grows from 60.61 PJ in 1999 to 105.9 PJ in 2025, however its contribution decreases from 9.82 to 6.61 percent.
- Hydro generation increases from 113.77 to 117.24 PJ in 2925, however, its share decreases from 18.43 to 7.32 percent;
- Geothermal generation growths from 19.37 to 24.1 PJ by 2025, its share in the total generation decreases from 3.14 to 1.5 percent;
- Nuclear generation contribution decreases from 34.26 to 17.13 PJ as a result of no nuclear additions and the retirement of unit 1 of Laguna Verde nuclear power plant, its share in the generation decreases from 5.55 to 1.07% by 2025;
- Diesel generation increases from 4.1 to 32.44 PJ with a share in the total generation of 0.66 to 2.02 percent by 2025; and,
- Wind participates in the total generation with a very small amount and a decreasing share of electricity imports from 0.38 to 0.07 percent by 2025.

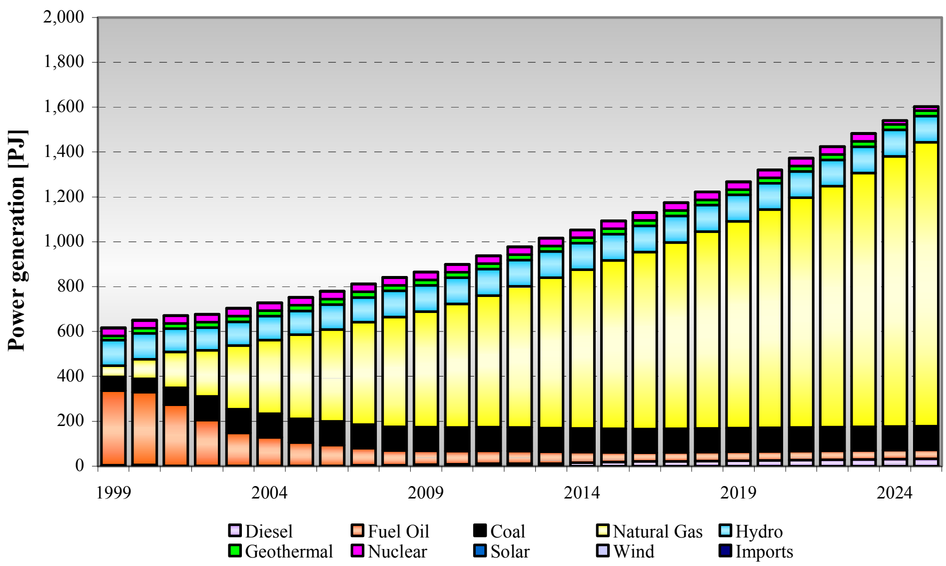

Figure 6.6 Power generation by fuel type (Reference case).

6.2. Final energy consumption

6.2.1. Final energy consumption by sector and by fuel

BALANCE projects total final energy consumption by sector. The results are given in Table 6.3 and graphically displayed in Figure 6.7. All the sectors show a growth in the energy consumption along the period 1999–2025, however with the exception of transport sector, the market share for all sectors shows a drop in terms of its contribution to the total final energy consumption. The main results are:

- The transport and industrial sectors represent, in 2025, more than 90 percent of the market share in terms of total final energy consumption. Both sectors are also the fastest growing sectors;
- The transport sector shows the highest average annual growth rate (4.9%) from 1,547.1 PJ in 1999 to 5,349.3 PJ in 2025 and its market share rises from 38.4 to 50.2 percent;
- The industrial sector is the second highest energy consumer with a 3.7% average annual growth rate. The industry sector consumed 1,560.7 PJ in 1999 and grows to 3,991.9 PJ in 2025, but its market share drops from 38.7 to 37.4 percent;
- The final energy consumption in agriculture sector increases from 116.9 PJ to 222.1 PJ with 2.5% average annual growth rate, but its market share falls from 2.9 to 2.1 percent;
- The commercial and public sectors consumed 119.4 PJ in 1999 and in 2025 arise to 211.5 PJ with a average annual growth rate of 2.2 percent, but its market share drops from 3.0 to 2.0 percent; and,
- The residential sector shows only a slight growth, an average annual growth rate of 1.01 percent but its market share drops sharply from 17 to 8.4 percent.

Table 6.3 Final energy consumption by sector (Reference case)

	1999	2000	2005	2010	2015	2020	2025
	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Residential	685.89	709.70	753.86	793.78	823.94	859.04	891.43
Transport	1 547.07	1 609.97	1 830.12	2 569.67	3 333.35	4 223.50	5 349.32
Industrial	1 560.70	1 517.63	1 674.13	2 104.10	2 589.42	3 189.85	3 991.89
Agriculture	116.90	115.32	118.70	117.70	143.22	179.19	222.08
Commercial and Public	119.40	131.75	105.47	125.90	150.25	178.71	211.50
Total	4 029.95	4 084.37	4 482.28	5 711.15	7 040.18	8 630.29	10 666.23

BALANCE also projects final energy consumption by fuel type. The results for the reference case are shown in Tables 6.4, 6.5 and Figure 6.8. The model projects the fuel shares to change as follows:

- Coke increase at an average annual growth rate of 4.9 percent from 91.5 to 320.1 PJ (2.3% to 3.0% of market share);
- Oil products grow at an average annual growth rate of 3.9 percent from 2,546 to 6,724.8 PJ and a slightly decrease in market share from 63.18 to 63.05 percent by 2025;

- Natural gas has a high average annual growth rate of 4.8 percent and increases from 526.6 to 1,764 PJ (increase by a factor of 3) and captures 16.5 percent of the market by 2025 (from 13.1% in 1999);
- Electricity growth with an average annual growth rate of 3.7 percent, increasing from 522.0 to 1,353.5 PJ (equal to 145 to 375.6 TW·h) while its share rises to 12.7 percent by 2025 (below from 13.0% in 1999). Industrial electricity consumption grows the fastest at 4.6% on average per year while residential electricity consumption is projected to grow at an average of 1.6% between 1999 and 2025; and,
- Renewables grow from 343.88 to 504.0 PJ representing an average annual growth rate of 1.5 percent. Their share falls from 8.5 to 4.7 percent.

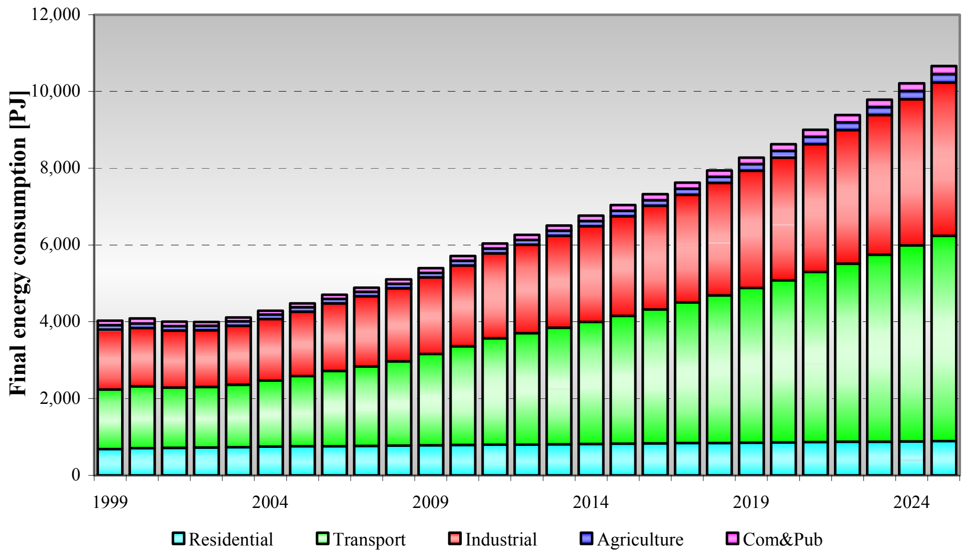

Figure 6.7 Final energy consumption by sector (Reference case).

Table 6.4 Energy consumption by fuel type (Reference case)

	1999 PJ	2000 PJ	2005 PJ	2010 PJ	2015 PJ	2020 PJ	2025 PJ
Coke	91.55	101.69	119.49	163.72	207.27	256.77	320.14
Oil products	2 546.03	2 572.94	2 766.14	3 592.24	4 443.17	5 447.59	6 724.78
Natural gas	526.64	519.27	597.03	799.67	1 038.20	1 346.81	1 764.02
Electricity	522.03	551.59	636.25	759.61	923.02	1 114.21	1 353.43
Renewables	343.88	339.05	363.54	396.07	428.69	465.08	504.03
Total	4 030.11	4 084.53	4 482.45	5 711.32	7 040.35	8 630.46	10 666.40

Table 6.5 Final energy consumption by fuel type (Reference case)

	1999	2000	2005	2010	2015	2020	2025
	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Coke	91.55	101.69	119.49	163.72	207.27	256.77	320.14
Fuel oil	210.82	210.87	152.67	128.95	108.53	94.00	85.72
Diesel	566.29	582.38	624.22	844.29	1 077.98	1 353.91	1 703.41
Gasoline	995.47	1 030.48	1 197.19	1 673.16	2 161.53	2 731.55	3 453.73
Kerosene	116.02	116.05	133.16	182.73	231.98	287.42	356.08
LPG	425.90	437.44	437.28	478.90	515.79	561.07	615.19
Natural gas	526.64	519.27	597.03	799.67	1 038.20	1 346.81	1 764.02
Electricity	522.03	551.59	636.25	759.61	923.02	1 114.21	1 353.43
Renewables	343.88	339.05	363.54	396.07	428.69	465.08	504.03
Non-energy products	231.52	195.72	221.62	284.22	347.36	419.64	510.66
Total	4 030.11	4 084.53	4 482.45	5 711.32	7 040.35	8 630.46	10 666.40

According to the actual energy policy, is expected that natural gas will have a substantial penetration in the final end use sectors and in the power sector. Therefore, it results convenient to look, in detail, on the projected increase of this energy fuel along the entire projection period. Total natural gas consumption is projected to increase from 799.4 PJ (526.5 PJ for the final consumption in the end use sectors plus 272.9 PJ for power generation) in 1999 to 4,677.99 PJ by 2025 as shown in Table 5.6 and Figure 5.9. The main results are as follows:

- Industry has a large growth for natural gas accounting for 4.6 percent of total growth. Industrial gas consumption increases from 500.4 to 1,614.7 PJ between 1999 and 2025 accounting for 34.5 percent of total gas consumption;
- With 24.3 percent, transport has the highest average annual growth rate for gas consumption of all the sectors during the period 2000–2025;
- Power generation is the second largest contributor to the overall growth in gas demand (34.1%) in 1999 and accounts for 62.3 percent of the total gas consumption in 2025. This represents a 9.54 percent annual average growth rate along the entire period. Clearly, this is related to the substantial amount of new gas-fired combined-cycle and gas turbine capacity projected to come on-line under the reference case;
- Residential gas consumption increases from 25.8 PJ in 1999 to 80.96 PJ in 2025 or the equivalent of a 4.49 percent average annual growth rate for the entire projection period; and
- According to the National Energy Balance, the commercial and public sectors do not consume natural gas, however, the study (Quintanilla, 2000) entitled “Massive Solar Energy Use for Water Heating in Substitution of Fossil Fuels in Valley of Mexico

Metropolitan Area (residential sector, hospitals, hotels and public baths) found that there is, already, some penetration of natural in the commercial sector. Recently, through the natural gas policy, there have been important investments by private natural gas distribution companies for distribution of natural gas in several cities of Mexico. Certainly, the main target is the residential sector, however, depending of how far is the end user from the distribution network and the required investment there will be a better probability of a higher natural gas penetration in some specific niches of the commercial sector; and,

- Agricultural sector do not represent a feasible candidate for natural gas penetration, at least, as a user of a conventional distribution network and, perhaps, under another distribution option could be a candidate as a user of this fuel.

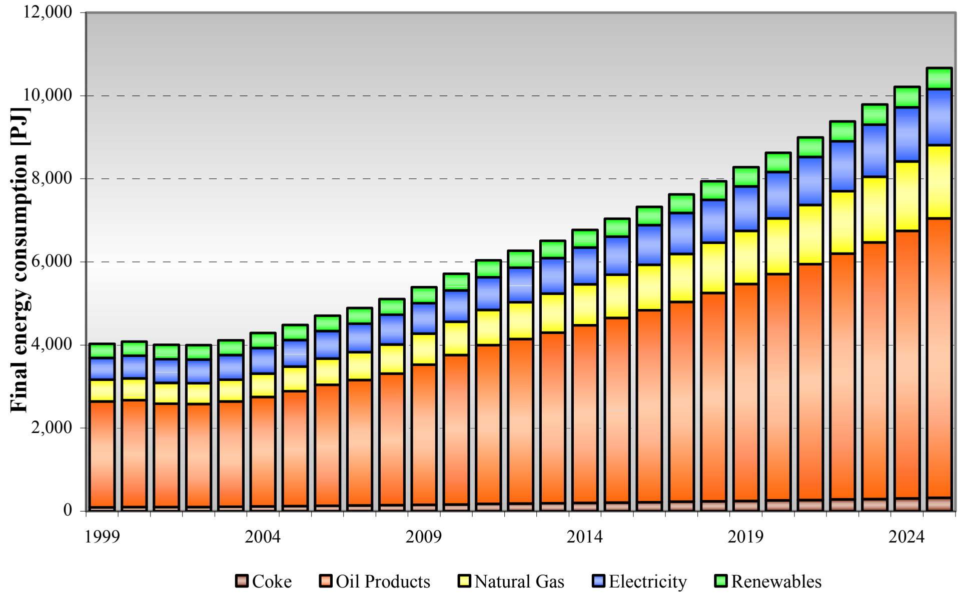

Figure 6.8 Final energy consumption by fuel type (Reference case).

As shown in Figure 6.9 projected final demand of natural gas for the industrial sector growths at an average annual growth rate of 4.6 percent passing from 500.41 to 1,614.87 PJ with important variations in the different sub-sectors. While chemical industry shows an above-average growth rate of 6.3, the cement industry will reduce its consumption of natural gas by 1.96 percent every year along the period of study.

Natural gas consumption in the glass industry grows steadily from 22.01 PJ in 1999 to 81.92 PJ in 2025 increasing its market share from 4.4 to 5.07 percent. In the same direction iron and steel industry shows a steadily increase of natural gas consumption passing from 103.06 PJ in 1999 to 399.13 PJ in 2025. Fertilizers industry will grow at the average rate of the whole industrial sector passing in absolute terms from 7.66 PJ in 1999 to 24.8 PJ in 2025.

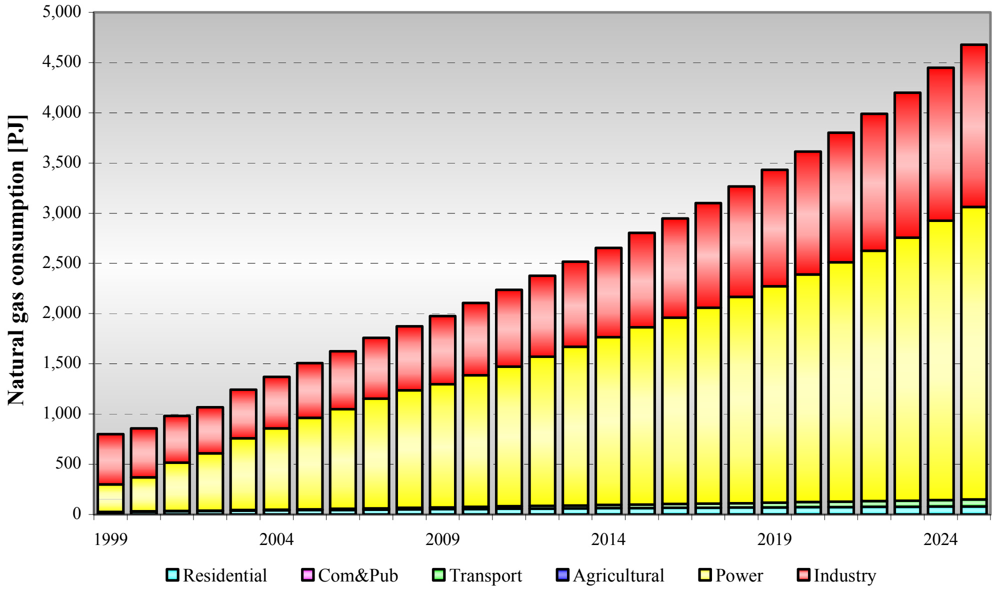

Figure 6.9 Natural gas consumption by sector (Reference case).

It is important to note in Table 6.6 how the drastic reduction in petrochemical production in Mexico will impact importantly, the natural gas consumption in the PEMEX-Petrochemical industry, which will increase at a far below-average growth rate of 1.6 percent passing from 155.15 PJ in 1999 to 232.35 PJ in 2025. This includes both fuel and row material uses for natural gas. The rest of the industrial sub-sectors will grow at above-average growth rates which explain the important increase in natural gas consumption in the industrial sector (mining (6.1%), Malt and beer (6.4 %), Automotive (5.6%), Paper and cellulose (5.1 %), Rubber (6.2%), Aluminum (5.9%), Tobacco (5.3 %), Bottled waters (6.4%) and Others (5.2%)).

6.2.2. Industrial energy consumption trends

Total industrial energy consumption grows at an average annual growth rate of 3.68 percent from 1,560.70 to 3,991.91 PJ between 1999 and 2025, as shown in Table 6.7 and Figure 6.10. Natural gas will continue to be the most important fuel in the industrial sector with almost 40.45 percent of total energy consumption in 2025. Average annual growth rate for natural gas is 4.61 percent just below electricity which grows at an average annual growth rate of 4.55 percent passing from 310.42 to 986.36 PJ in the same period. This represents an increase for electricity in market penetration of almost 5 percent passing from 19.89 percent in 1999 to 24.71 percent in 2025. For the rest of the demand sectors fuel oil will continue its decline in the market from 12.98 percent in 1999 to 1.98 percent in 2025 passing in absolute terms from 202.58 to 79.03 PJ. This is in accordance with environmental restrictions imposed by the Mexican Government in recent years, which impose severe limits on fuel oil consumption for the industrial and other sectors.

Coke grows steadily in share from 5.87 to 8.02 percent growing noticeably in absolute terms from 91.55 to 320.14 PJ. This important increase comes mainly from the cement industry, which recently began to use this fuel in its processes, and will continue to do so. Nevertheless, this sector has been substituting some conventional fuels by the so called “alternatives fuels”, namely, waste lubricants and oils, tires, etc. These alternatives fuels were not reported in the National Energy Balances, except for some initial comments and figures in the 2001 National

Energy Balance. Therefore, if available, this information will have to be incorporated in future versions of the model.

Table 6.6 Natural gas consumption by sector and sub-sector (Reference case)

	1999 PJ	2000 PJ	2005 PJ	2010 PJ	2015 PJ	2020 PJ	2025 PJ
Residential	**25.82**	**29.72**	**43.97**	**56.18**	**65.45**	**73.86**	**80.96**
Commercial and Public							
Transport	**0.24**	**1.68**	**9.34**	**21.07**	**34.34**	**49.63**	**68.21**
Agricultural							
Power sector	**272.87**	**338.63**	**910.23**	**1 308.18**	**1 765.05**	**2 266.55**	**2 914.13**
Industrial	**500.41**	**487.71**	**543.55**	**722.27**	**938.24**	**1 223.16**	**1 614.69**
Iron and steel	103.06	112.85	133.61	190.49	248.53	315.24	399.12
Glass	22.01	23.77	25.62	36.49	48.68	63.01	81.93
Sugar							
Cement	10.95	11.14	7.52	6.89	6.30	6.12	6.55
PEMEX-Petrochemicals	155.14	140.44	145.59	164.11	179.90	200.87	232.35
Fertilizers	7.66	6.46	6.41	8.99	12.61	17.68	24.80
Chemicals	65.30	72.24	81.84	114.78	160.99	225.79	316.69
Mining	26.22	27.16	31.53	44.23	62.03	87.00	122.03
Paper and cellulose	18.42	16.11	17.35	24.33	34.13	47.87	67.13
Malt and beer	7.91	8.43	10.26	14.39	20.18	28.30	39.70
Automotive	3.05	2.68	3.28	4.60	6.46	9.06	12.70
Construction							
Rubber	2.82	2.96	3.51	4.93	6.91	9.69	13.59
Aluminum	3.70	3.55	4.24	5.95	8.34	11.70	16.41
Tobacco	0.29	0.22	0.29	0.41	0.57	0.81	1.13
Bottled waters	1.90	2.03	2.44	3.42	4.80	6.73	9.44
Others	71.97	57.65	70.06	98.26	137.82	193.30	271.12
Total	**526.48**	**519.11**	**596.87**	**799.51**	**1 038.04**	**1 346.65**	**1 763.86**

Under the reference case renewables for industrial sector increase at below average rates (3.3% per year) passing in absolute terms from 91.98 to 213.95 PJ. This leads to a reduction from 5.89 percent of total industrial energy consumption in 1999 to 5.36 percent by 2025. The main increase is due to the sugar cane bagasse consumption as fuel for electricity generation and process heat in the sugar sector. No other renewable energies development is visualized in this sector. In the same direction diesel will decrease its market share in the industrial sector passing from 3.49 to 3.11 percent but increasing in absolute terms from 54.41 to 124.28 PJ along the projection period.

While kerosene and gasoline continues to have a very small contribution in energy consumption, non-energy products grow in absolute terms from 231.52 to 510.66 PJ but still decline in the market from 14.83 percent in 1999 to 12.79 percent in 2025. Additionally, some of the considered energy sources (petroleum coke, LPG, gasoline and kerosene) are used in the industrial sub-sectors as raw material for their processes.

Table 6.7 Industrial energy consumption by fuel type (Reference case)

	1999	2000	2005	2010	2015	2020	2025
	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Coke	91.55	101.69	119.49	163.72	207.27	256.77	320.14
Fuel oil	202.58	201.60	150.23	125.73	104.35	88.71	79.03
Diesel	54.41	50.56	55.28	70.10	85.28	102.80	124.28
Kerosene	0.59	0.48	0.54	0.68	0.83	1.00	1.21
LPG	38.71	33.54	36.99	47.01	56.95	68.36	82.22
Natural gas	231.52	195.72	221.62	284.22	347.36	419.64	510.66
Non energy products	500.41	487.71	543.55	722.27	938.24	1 223.16	1 614.69
Gasoline	38.52	34.67	35.30	40.51	45.34	51.06	59.38
Electricity	310.42	327.12	408.09	518.52	646.37	793.64	986.36
Renewables	91.98	84.54	103.04	131.35	157.45	184.72	213.95
Total	**1 560.70**	**1 517.63**	**1 674.13**	**2 104.10**	**2 589.43**	**3 189.87**	**3 991.91**

As shown in Table 6.8 projected total fuel consumption for the industrial sub-sectors that have been analyzed in an aggregated way growths at an annual average rate of 3.68 percent passing from 1,560.70 PJ in 1999 to 3,991.91 PJ in 2025. No significant variations exist in the energy consumption trends of the different sub-sectors as well in the market penetration in every one of them. This is due to the fact that for these sub-sectors there wasn't information for their splitting by service type (steam and process heat as well as electricity generation), therefore the introduced configuration of these sub-sectors in the model wouldn't allow the substitution between fuels in those sub-sectors as well as efficiency improvements. Energy demand in those sub-sectors is driven by final demand growth rates, which even that differ between them; do not disaggregate into service type. This calls for an effort for the generation of this type of information and knowledge.

Aluminum industry shows the highest growth rate with 5.54 percent, which leads to an increase from 5.2 PJ in 1999 to 21.13 PJ in 2025 in absolute terms, while chemical, rubber, construction, automotive, malt and beer, and tobacco also show above-average growth rates, energy consumption in fertilizers, paper and cellulose and bottled waters industries are under the average.

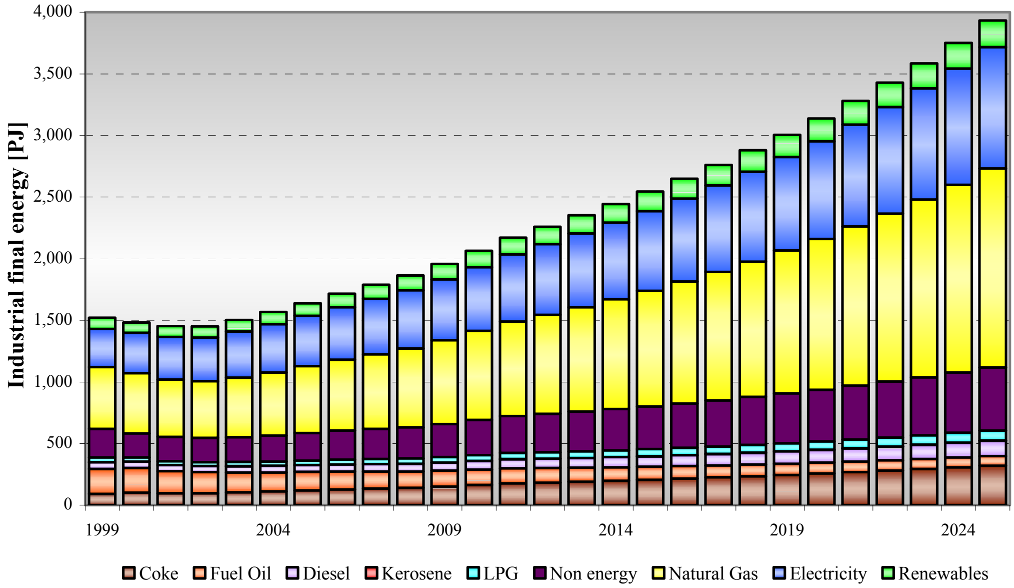

Figure 6.10 Industrial final energy consumption by fuel type (Reference case).

Table 6.9 shows the projected final energy consumption of the iron and steel industry that increase from 247.7 PJ in 1999 to 649.01 PJ with an annual average growth rate of 3.77 percent for the period. The fastest growing fuel consumption is diesel consumption, far above the average growth rate with 6.2 percent per year passing from 1.28 PJ in 1999 to 6.12 PJ in 2025. Natural gas also has an important increase in consumption of 5.35 percent average growth rate per year passing from 103.06 PJ in 1999 to 399.12 PJ in 2025. This leads to market participation for natural gas of 61.5 percent in 2025. In the same direction electricity grows 4.99 percent a year rising from 31.04 PJ in 1999 to 110.24 PJ in 2025. Electricity from co-generation does not penetrate as rapid as electricity from the grid does with an increase of only 2.01 percent per year.

Important is to note the average annual reduction of 0.54 percent in fuel oil consumption passing in absolute terms from 20.84 PJ in 1999 to 18.11 PJ in 2025. Coke consumption grows in absolute terms from 85.29 PJ in 1999 to 106.08 PJ in 2025 but decrease importantly its participation in total energy consumption in this sector from 34.43 to 16.34 percent in the same period. Non-energy products and LPG will continue to have a very small participation in the energy consumption of this industrial sub-sector.

As shown in Table 6.10, the projected glass industrial sub-sector final energy consumption will increase at an annual average growth rate of 5.06 percent passing from 31.22 PJ in 1999 to 112.58 PJ. The fastest growing consumption in this sector is electricity from self-generation with an annual average growth rate of 15.1 percent but very small participation in absolute terms and market participation with 0.92 PJ and 0.82 percent in 2025, respectively. Non-energy products and coke consumption grow rapidly at 5.83 percent per year but its participation remains relatively small. Diesel consumption is under the average growth rate with 4.26 percent per year passing from 1.85 PJ in 1999 to 5.47 PJ in 2025.

Table 6.8 Total fuel consumption by industrial sub-sector (Reference case)

	1999	2000	2005	2010	2015	2020	2025
	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Iron and steel	244.01	259.57	279.07	358.15	435.43	525.97	642.82
Glass	31.19	33.68	37.29	51.83	67.95	86.83	111.65
Sugar	122.49	110.92	123.97	148.46	170.16	193.26	218.54
Cement	95.22	105.97	118.02	163.06	211.75	269.01	344.68
PEMEX-Petrochemicals	264.03	239.68	247.10	280.19	309.13	345.68	400.23
Fertilizers	12.23	10.64	10.15	12.81	16.73	22.34	30.30
Chemical	136.03	149.38	153.70	185.78	235.42	308.03	412.00
Mining	66.12	68.49	71.44	87.72	109.73	139.94	181.66
Paper and cellulose	46.20	42.23	42.64	51.14	63.75	81.81	107.31
Beer	15.02	16.00	17.39	21.08	26.93	35.52	47.87
Automotive	11.14	10.61	13.42	18.18	23.55	30.33	39.25
Construction	7.24	7.72	9.45	13.08	16.82	21.09	26.71
Rubber	5.71	6.00	6.93	8.93	11.59	15.23	20.26
Aluminum	5.20	5.10	6.19	8.44	11.43	15.49	21.13
Tobacco	0.55	0.48	0.60	0.78	1.02	1.35	1.80
Bottled waters	9.79	10.41	11.45	13.91	16.90	20.77	25.89
Others	488.54	440.76	525.32	680.56	861.16	1 077.23	1 359.82
Total	1 560.70	1 517.63	1 674.13	2 104.10	2 589.43	3 189.87	3 991.91

Natural gas has an important increase in consumption of 5.18 percent per year passing from 22.01 PJ in 1999 to 81.93 PJ in 2025. This leads to a small increase in market participation for natural gas passing from 70.51 percent in 1999 to 72.77 percent in 2025. It is to notice the reduction in market participation of electricity passing from 13.54 percent in 1999 to 11.84 percent in 2025, electricity from the grid growths at a 4.51 percent per year. On the opposite electricity from co-generation penetrate more rapidly than electricity from the grid with an increase of 15.1 percent per year.

Sugar industry final energy consumption as Table 6.11 shows is intended to increase at a below-average growth rate of 2.36 percent passing from 125.5 PJ in 1999 to 230.35 PJ in 2025. Sugar cane bagasse participation will continue to be the most important energy source in the sugar sub-sector passing from 68.99 percent in 1999 to 87.9 percent in 2025 and from 86.58 PJ to 202.47 PJ in the same period. The fastest growing consumption in this sector is diesel with an annual average growth rate of 14.12 percent but very small participation in absolute terms and market participation with 1.5 PJ and 0.65 percent in 2025, respectively. It is to notice the reduction in market participation of electricity passing from 0.43 percent in 1999 to zero percent in 2005, which will be compensated by an increase of electricity from co-generation passing from 3.02 PJ in 1999 to 11.81 PJ in 2025 Important is to note the average annual growth rate reduction of 3.35 percent in fuel oil consumption passing in absolute terms from 35.28 PJ in 1999 to 14.54 PJ in 2025. LPG consumption will continue to be insignificant passing in absolute terms from 0.04 PJ in 1999 to 0.03 PJ in 2025.

Table 6.9 Iron and steel sub-sector energy consumption by fuel type (Reference case)

	1999	2000	2005	2010	2015	2020	2025
	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Fuel oil	20.84	21.28	17.85	18.55	18.27	18.01	18.11
Diesel	1.28	1.51	2.02	2.83	3.73	4.79	6.12
LPG	0.91	0.95	0.88	0.99	1.04	1.10	1.19
Natural gas	103.06	112.85	133.61	190.49	248.53	315.24	399.12
Coke	85.29	88.54	79.36	87.13	91.33	97.06	106.08
Non energy products	1.58	1.64	1.47	1.61	1.69	1.79	1.96
Electricity from cogeneration	3.70	3.88	3.70	4.34	4.85	5.43	6.20
Electricity	31.04	32.80	43.88	56.56	70.84	87.98	110.24
Total	**247.70**	**263.44**	**282.77**	**362.49**	**440.27**	**531.40**	**649.01**

As shown in Table 6.12 projected final energy consumption in the cement industry is intended to increase at an annual average growth rate of 5.07 percent passing from 95.22 PJ in 1999 to 344.68 PJ in 2025. Contrary to the situation in 1999 where fuel oil participates with 73.37 percent of total final energy consumption in this sub-sector, in 2025 this fuel will only take 6.87 percent of the market share. This reduction is to be compensated by coke and non-energy products (alternative fuels as oils, waste lubricants, used tires etc.), which will grow from 0 PJ in 1999 to 65.52 PJ and 200.62 PJ in 2025, respectively. This represents an annual average growth rate of 14.66 percent for each one of them. Electricity consumption will increase at an average annual growth rate of 4.76 percent passing from 14.4 PJ in 1999 to 48.3 PJ in 2005. This sub-sector is an exception in terms of natural gas consumption, which declines at an average rate of 1.96 percent passing from 10.95 PJ in 1999 to 6.55 PJ in 2025.

Table 6.10 Glass sub-sector final energy consumption by fuel type (Reference case)

	1999	2000	2005	2010	2015	2020	2025
	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Fuel oil	1.86	2.04	2.23	3.03	3.82	4.63	5.61
Diesel	1.85	2.00	2.08	2.73	3.46	4.33	5.47
LPG	0.20	0.22	0.26	0.37	0.47	0.58	0.73
Natural gas	22.01	23.77	25.62	36.49	48.68	63.01	81.93
Coke	1.03	1.17	1.39	1.99	2.65	3.45	4.51
Non energy products	0.02	0.02	0.03	0.04	0.05	0.06	0.08
Electricity from cogeneration	0.02	0.04	0.14	0.27	0.44	0.66	0.92
Electricity	4.23	4.45	5.68	7.18	8.82	10.78	13.32
Total	**31.22**	**33.72**	**37.43**	**52.11**	**68.39**	**87.49**	**112.58**

Table 6.11 Sugar sub-sector final energy consumption by fuel type (Reference case)

	1999	2000	2005	2010	2015	2020	2025
	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Fuel oil	35.28	30.25	25.49	22.86	19.63	16.81	14.54
Diesel	0.05	0.09	0.30	0.55	0.84	1.15	1.50
LPG	0.04	0.03	0.03	0.03	0.03	0.03	0.03
Sugar cane bagasse	86.58	80.22	98.15	125.02	149.67	175.27	202.47
Electricity from cogeneration	3.02	3.42	4.82	6.18	7.68	9.47	11.81
Electricity	0.54	0.33	0.00	0.00	0.00	0.00	0.00
Total	125.50	114.34	128.79	154.64	177.84	202.73	230.35

Table 6.12 Cement sub-sector final energy consumption by fuel type (Reference case)

	1999	2000	2005	2010	2015	2020	2025
	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Fuel oil	69.86	70.91	46.56	40.14	33.00	27.28	23.69
Natural gas	10.95	11.14	7.52	6.89	6.30	6.12	6.55
Coke	0.00	6.57	33.33	68.43	106.34	148.41	200.62
Non energy products	0.00	2.15	10.88	22.35	34.73	48.47	65.52
Electricity	14.40	15.21	19.72	25.25	31.38	38.73	48.30
Total	**95.22**	**105.97**	**118.02**	**163.06**	**211.75**	**269.01**	**344.68**

Table 6.13 presents the results of the projected PEMEX Petrochemical final energy consumption that increase from 282.651 PJ in 1999 to 434.060 PJ with an annual average growth rate of 1.66 percent for the period. The fastest growing fuel consumption is fuel oil increasing 11.1 percent per year but not very significant in absolute terms passing from 0 PJ in 1999 to 4.65 PJ in 2025. Natural gas shows increase in consumption with an average annual growth rate of 1.57 percent per year passing from 155.14 PJ in 1999 to 232.35 PJ in 2025. This leads to market participation for natural gas of 53.53 percent in 2025. In the same direction electricity from cogeneration and self-generation grows at a 2.32 percent a year rising from 18.62 PJ in 1999 to 33.82 PJ in 2025.

Diesel consumption in the PEMEX Petrochemical final energy consumption will increase at an average growth rate 3.41 percent per year passing from 0.56 PJ in 1999 to 1.34 PJ in 2025. Gasoline consumption increase at an average growth rate 1.56 percent per year passing from 35.66 PJ in 1999 to 53.29 PJ in 2025, this gasoline consumption corresponds to its use as a raw material. Non energy products will growth at an average annual growth rate of 1.56 percent passing from 72.17 PJ in 1999 to 107.84 PJ by 2025. Kerosene and LPG will continue to have a very small participation in the energy consumption of this industrial sub-sector, but their main use is as a raw material.

Table 6.13 PEMEX Petrochemical sub-sector final energy consumption by fuel type (Reference case)

	1999 PJ	2000 PJ	2005 PJ	2010 PJ	2015 PJ	2020 PJ	2025 PJ
Fuel oil	0.00	0.33	1.51	2.40	3.12	3.83	4.65
Diesel	0.56	0.54	0.67	0.81	0.95	1.12	1.34
LPG	0.43	0.39	0.39	0.44	0.49	0.55	0.64
Natural gas	155.14	140.44	145.59	164.11	179.90	200.87	232.35
Kerosene	0.08	0.07	0.07	0.08	0.09	0.10	0.12
Gasoline	35.66	32.38	32.70	37.15	41.20	46.04	53.29
Non energy products	72.17	65.53	66.18	75.19	83.39	93.17	107.84
Electricity from cogeneration	18.62	17.03	18.67	22.00	24.94	28.61	33.82
Total	**282.65**	**256.72**	**265.78**	**302.19**	**334.08**	**374.29**	**434.05**

Table 6.14 Residential sector final energy consumption (Reference case)

	1999 PJ	2000 PJ	2005 PJ	2010 PJ	2015 PJ	2020 PJ	2025 PJ
Firewood	251.90	253.61	255.93	258.29	260.26	263.07	265.65
LPG	286.51	296.30	308.95	321.85	330.97	344.87	358.68
Kerosene	1.54	1.69	2.20	2.56	2.82	3.04	3.21
Natural gas	25.82	29.72	43.97	56.18	65.45	73.86	80.96
Electricity	120.12	128.21	142.01	153.68	162.92	172.48	181.05
Renewables	0.00	0.16	0.81	1.23	1.51	1.73	1.88
Total	**685.89**	**709.70**	**753.86**	**793.78**	**823.94**	**859.04**	**891.43**

6.2.3. Residential energy consumption trends

Residential energy consumption will increase by 29.97 percent during the 1999-2025 period with an average annual growth rate of 1.01 percent, passing from 685.89 PJ in 1999 to 891.43 PJ by 2025 (Table 6.14 and Figure 6.11). LPG will continue as the most important fuel source in the sector (286.51 PJ in 1999 and 358.68 PJ in 2025), its average annual growth rate will be 0.87 percent along the period.

Firewood comes in second place (251.90 PJ in 1999 and 265.65 PJ in 2025) with an average annual growth rate of 0.2 percent for the entire period. Kerosene will growth at 2.87 percent average annual growth rate, however, in absolute terms its participation is small (1.54 PJ in 1999 and 3.21 PJ in 2025).

On the other hand, natural gas penetrates with an average annual growth rate of 4.49 percent along the entire period, passing from 25.82 PJ in 1999 to 80.96 PJ by 2025. Natural gas penetration will be in competition with LPG for cooking and water heating. Electricity grows from 120.12 PJ in 1999 to 181.05 PJ by 2025, an average annual growth rate of 1.59 percent.

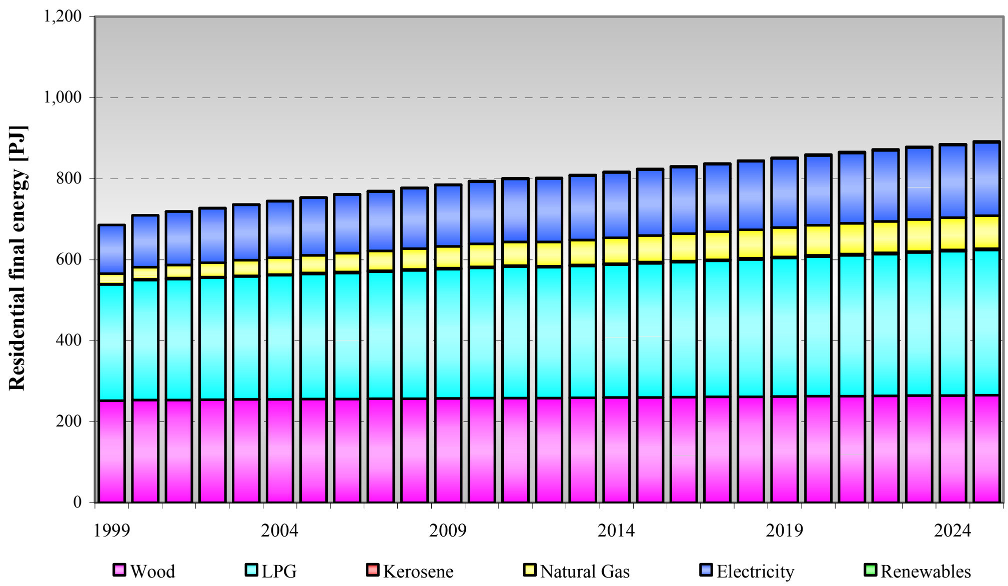

Figure 6.11 Residential sector energy consumption by fuel type (Reference case).

Finally, renewables through solar energy contributes to satisfy the demand for water heating and lighting with an average annual growth rate of 10.22 percent, which means an increase from 0.16 PJ in 2000 to 1.88 PJ by 2025. The solar technologies included in this sector are: passive solar water heating with LPG back-up, solar water heating without backup ([4], 2000) and solar PV cells for electricity generation.

Looking at the final energy consumption by end use (Figure 6.12), the majority of energy is consumed and will be in cooking activities, an average of 55.6 percent of the total energy consumption in the sector along the period. Another major area of energy consumption in the domestic sector are will be water heating, in average 27.3 percent of the total energy is consumed for the satisfaction of this end use. Lighting represents, also in average, the 6.71 percent of the total energy consumption; refrigeration or food preservation covers, in average along the period, 4.31 percent of the total energy consumption. Electrical appliances energy consumption represents the 4.92 percent and space conditioning the remaining 1.2 percent of the total energy consumption in the sector. Recent efficiency standards for domestic and commercial refrigerators allow thinking in lower electricity consumption for this end use.

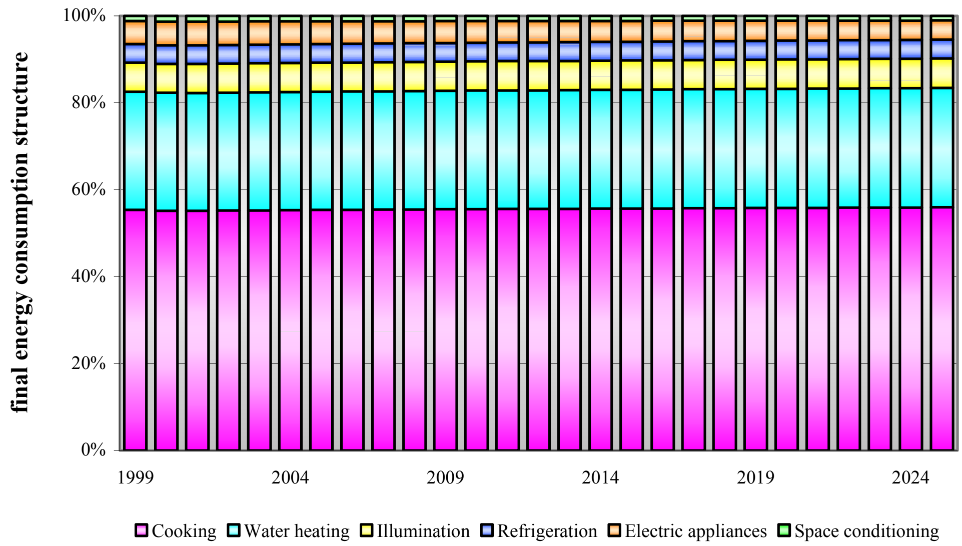

Figure 6.12 Residential sector final energy consumption structure by end use (Reference case).

Table 6.15 Transport sector final energy consumption (Reference case)

	1999 PJ	2000 PJ	2005 PJ	2010 PJ	2015 PJ	2020 PJ	2025 PJ
Gasoline	956.95	995.81	1 161.89	1 632.65	2 116.20	2 680.50	3 394.35
Diesel	428.80	449.45	483.36	676.78	881.60	1 122.24	1 426.55
Kerosene	113.83	113.82	130.37	179.42	228.25	283.28	351.55
LPG	35.35	35.79	37.58	48.19	56.99	66.71	81.27
Fuel Oil	8.24	9.26	2.44	3.22	4.18	5.29	6.69
Natural Gas	0.24	1.68	9.34	21.07	34.34	49.63	68.21
Electricity	3.66	3.86	3.46	4.78	6.11	7.82	9.85
Hybrid	0.00	0.29	1.67	3.58	5.67	8.04	10.85
Total	**1 547.07**	**1 609.97**	**1 830.12**	**2 569.67**	**3 333.35**	**4 223.50**	**5 349.32**

6.2.4. Transportation energy consumption trends

The projected transportation final energy consumption trends under the reference case are shown in Table 6.15 and Figure 6.13. Total transport energy demand is expected to grow at an average annual growth rate of 4.89 percent from 1,547.07 to 5,349.32 PJ along the projection period. Gasoline is expected to grow at a 4.99 percent average annual growth rate along the entire period, while diesel will increase at an average annual growth rate of 4.73 percent. Kerosene and LPG will increase with average annual growth rates of 4.43 and 3.25 percent, respectively. On the other hand, fuel oil will decrease at an average annual growth rate of 0.8 percent as a result of the environmental policy and the trend of reduction of the maritime transportation mode; this also will affect the diesel consumption in this transportation mode. Natural gas participation in the road transport mode will increase substantially, at an average annual growth rate of 24.27 percent. In this sense it will remain to see how real is this rate of penetration under constraints on the availability of natural gas and transportation infrastructure.

Electricity is projected to increase its participation at an average annual growth rate of 3.89 percent; however, this will depend on the expansion of the mass transport systems in the main cities of the country and the re-activation of the rail transport mode through the introduction, if any, of the electrified railroad transport mode.

As was mentioned in Chapter 5, hybrid transport alternatives refer to vehicles that use hydrogen and electricity. Actually, the projections only consider electric vehicles with electricity generated by renewable energy sources such as solar and wind. If this turns out to be a reality, hybrid energy could increase at an average annual growth rate of 15.56 percent; this represents a growth from zero contribution to 10.85 PJ by 2025. It is assumed that the penetration of hybrid option will be in substitution of gasoline and/or natural gas in the road transport mode.

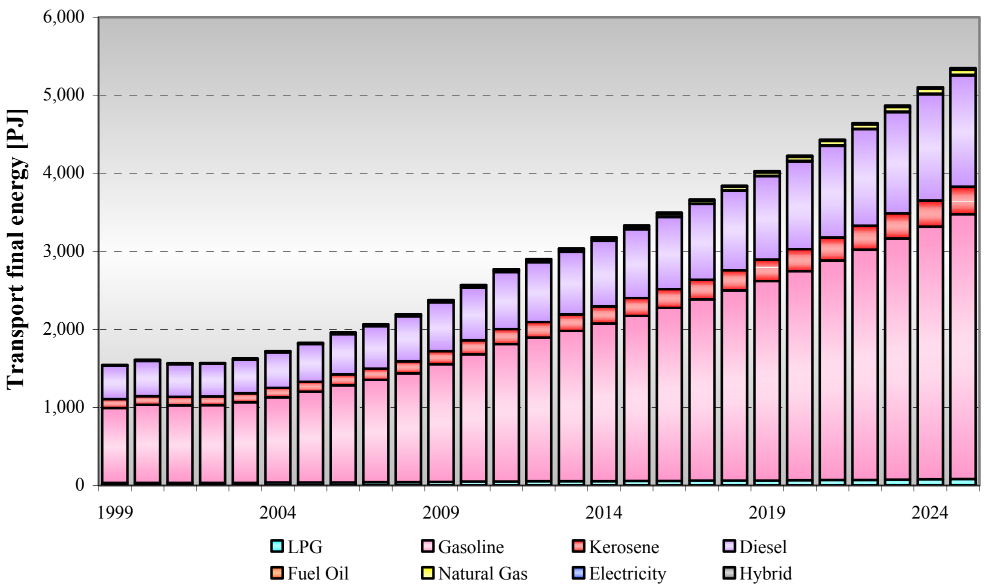

Figure 6.13 Transport sector final energy consumption by fuel type (Reference case).

In 1999, road transport energy consumption (Table 6.16) was 87.71 percent of the total energy consumption in the sector, in 2025 this will account for 90.22 percent. Energy consumption by road transport more than triples from 1,356.97 PJ in 1999 to 4,826.43 PJ in 2025. The main fuels consumed by road transport are gasoline and diesel accounting for about 96.68 percent of total fuel demand of the road sub-sector in 2025. The fuel mix for road transport will be 69.39 percent gasoline, 27.29 percent diesel and the rest for LPG, natural gas and hybrid. Gasoline will increase from 955.99 to 3,349.13 PJ with a small contraction in market share (70.45% to 69.39%) during 1999–2025. Diesel is projected to grow from 365.38 PJ to 1,316.96 PJ resulting in a minor increase in market share (26.93% to 27.29%).

Table 6.16 Transport sector energy consumption by mode type (Reference case)

	1999	2000	2005	2010	2015	2020	2025
	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Road							
Gasoline	955.99	994.32	1 157.14	1 621.94	2 097.29	2 650.52	3 349.13
Diesel	365.38	380.39	444.83	623.91	813.10	1 035.68	1 316.96
Natural gas	0.24	1.68	9.34	21.07	34.34	49.63	68.21
GLP	35.35	35.79	37.58	48.19	56.99	66.71	81.27
Hybrid	0.00	0.29	1.67	3.58	5.67	8.04	10.85
Subtotal	**1 356.97**	**1 412.47**	**1 650.57**	**2 318.68**	**3 007.39**	**3 810.58**	**4 826.43**
Rail							
Diesel	21.87	22.35	26.23	36.63	47.41	59.91	75.88
Sea							
Fuel oil	8.24	9.26	2.44	3.22	4.18	5.29	6.69
Diesel	41.55	46.71	12.31	16.24	21.10	26.66	33.72
Subtotal	**49.79**	**55.97**	**14.75**	**19.46**	**25.29**	**31.94**	**40.40**
Air							
Jet fuel	113.83	113.82	130.37	179.42	228.25	283.28	351.55
Gasoline	0.96	1.49	4.75	10.71	18.90	29.97	45.21
Subtotal	**114.79**	**115.31**	**135.11**	**190.12**	**247.16**	**313.26**	**396.77**
Electric							
Electricity	3.66	3.86	3.46	4.78	6.11	7.82	9.85
Total	**1 547.07**	**1 609.97**	**1 830.12**	**2 569.67**	**3 333.35**	**4 223.50**	**5 349.32**

Fuel demand by air transport is divided in two fuel types: jet fuel and gasoline, the market share is dominated by the jet fuel (99.17% in 1999 and 88.6% in 2025). On the other hand there are no practical alternatives to kerosene-based fuels for air transport in the next decades. Jet fuel is forecasted to grow from 113.83 in1999 to 351.55 PJ in 2025 while gasoline for this transport mode will grow from 0.96 PJ in 1999 to 45.21 PJ by 2025.

Electric transportation (subway and trolleys) represent only 0.24 percent in 1999 of the total energy consumption in the sector and will represent 0.18 percent by 2025, this means an increase from 3.66 PJ in 1999 to 9.85 PJ by 2025.

Sea transport mode represents 3.22 percent in 1999 and 0.75 percent by 2025. As was mentioned the main reason for this behavior lie the lack of interest in this transport mode. Finally, rail transport mode represents 1.41 percent participation in the total energy consumption of the sector, even that the consumption of diesel in this transport mode will increase from 21.87 PJ in 1999 to 75.88 PJ by 2025; the share remains constant as there are no clear expectations for any kind of expansion.

6.2.5. Agriculture energy consumption trends

Agriculture energy use is small compared to other economic sectors and accounts for about 2.9 percent of total energy consumption in 1999. By 2025 its share will account for 2.08 percent of the total energy consumption in the country. This implies an average annual growth rate of 2.5 percent along the entire period. In absolute terms energy consumption in the sector will increase from 116.9 PJ in 1999 to 222.08 PJ by 2025 (Table 6.17 and Figure 6.14). Therefore, under the assumed economic conditions, this sector will continue to be a low energy consumption sector, unless the current discussions for a stronger support by the government conduct to a bigger development of the sector in the coming years.

Table 6.17 Agriculture sector energy consumption (Reference case)

	1999 PJ	2000 PJ	2005 PJ	2010 PJ	2015 PJ	2020 PJ	2025 PJ
Diesel	79.57	78.46	82.81	94.22	107.43	124.68	147.83
LPG	8.48	8.36	8.82	10.04	11.44	13.28	15.75
Kerosene	0.06	0.06	0.06	0.07	0.08	0.09	0.11
Electricity	28.79	28.01	24.93	11.74	20.47	33.60	46.69
Electricity (renewables)	0.00	0.43	2.09	1.63	3.80	7.53	11.71
Total	**116.90**	**115.32**	**118.70**	**117.70**	**143.22**	**179.19**	**222.08**

Activities in this sector include mechanical field conditioning, pumping, irrigation, mechanical fertilization, seed drying, air conditioning for livestock, fence electrification, product conditioning and other activities. Even though activities are well determined, energy utilization is not and little official or academic data exists.

Petroleum byproducts, mainly diesel, LPG and kerosene, account for 75.37 percent of total agricultural energy consumption in 1999 and 73.70 percent by 2025, the remaining shares correspond to electricity. Average annual growth rates for diesel, LPG and kerosene will be 2.41 percent; depending on the degree of disaggregation of the energy use by specific end use in this sector is expected that these average annual growth rates will differentiate between them and conduct to a more representative image of the energy consumption in the sector. Electricity grows at an average annual growth rate of 2.13 percent; this last energy source includes electricity from renewable energy sources (at an average annual growth rate of 0.25 percent). Because of lack of more data, a business-as-usual trend was established which delivered a constant growth in diesel consumption and an erratic behavior for electricity. Nevertheless, the agricultural sector could become an important player in a renewable energy scenario.

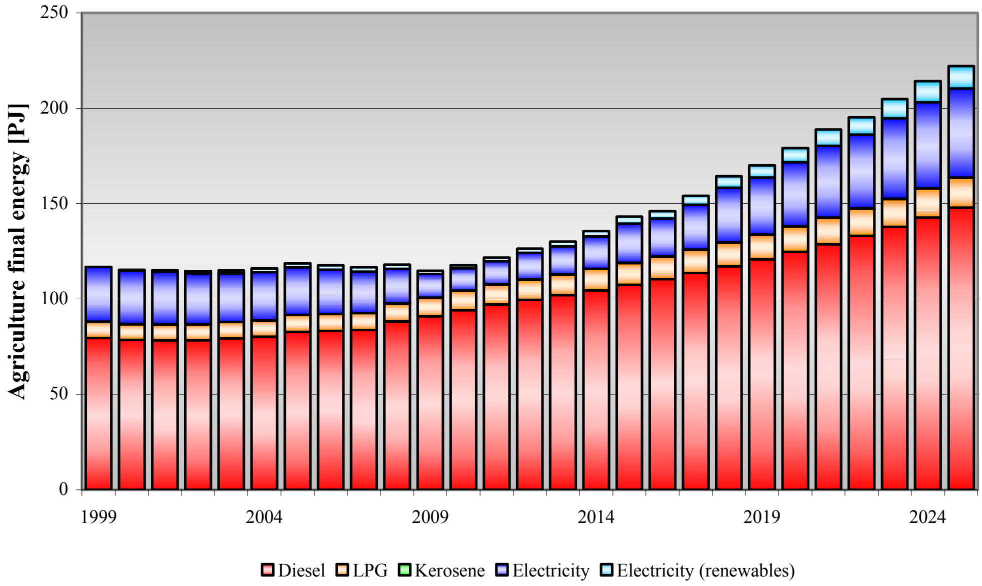

Figure 6.14 Agriculture sector final energy consumption (Reference case).

6.2.6. Commercial and public energy consumption trends

As was stated in Chapter 4, public sector consumption is defined by two activities: public illumination and public water pumping and only consumes electricity. The electricity consumption trend was established to grow over the period 1999–2025 at an average annual growth rate of 5.1 percent. Also, this sector has a good potential for electricity generated through renewable energies, both biomass and solar.

Table 6.18 Commercial and public sectors energy consumption (Reference case)

	1999	2000	2005	2010	2015	2020	2025
	PJ	PJ	PJ	PJ	PJ	PJ	PJ
LPG	56.86	63.45	44.93	51.81	59.43	67.85	77.27
Diesel	3.50	3.91	2.77	3.19	3.66	4.18	4.76
Electricity	59.04	64.39	57.77	70.90	87.15	106.68	129.47
Total	**119.40**	**131.75**	**105.47**	**125.90**	**150.25**	**178.71**	**211.50**

In the commercial sector occurs the same as in other energy demand sectors in Mexico, lack of disaggregated data, so energy consumption trends are established by the data available. Electricity and LPG (Table 6.18 and Figure 6.15) account, on average, for more than 96.45 percent of total commercial energy consumption, this fuel mix is kept constant throughout the period of projection, and growth is established at an annual rate of 1.19 percent.

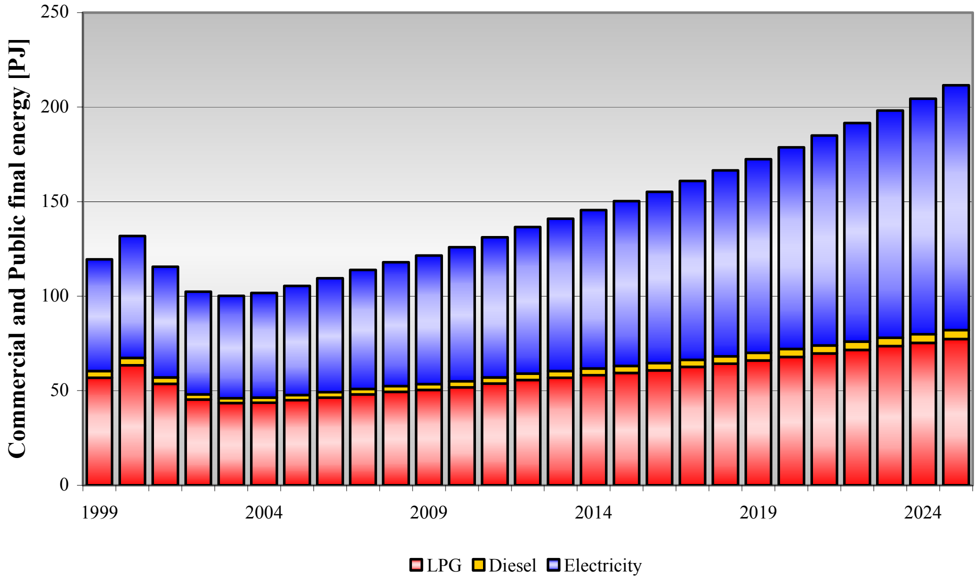

Figure 6.15 Commercial and Public sectors final energy consumption (Reference case).

Table 6.19 Energy and non-energy products imports (Reference case)

	1999	2000	2005	2010	2015	2020	2025
	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Gasoline	195.51	133.27	75.62	515.36	967.95	1 527.02	2 276.21
Diesel	57.45	52.95	0.00	178.54	448.61	749.05	1 122.17
LPG	127.89	95.14	24.68	13.59	15.54	83.60	219.35
Kerosene	5.63	100.81	128.80	159.80	187.50	199.84	199.84
Fuel oil	217.30	187.53	0.00	0.00	0.00	0.00	0.00
Non-energy products	0.00	7.29	0.00	0.00	0.00	100.61	191.99
Coal	61.63	20.83	146.75	146.75	146.75	146.75	146.75
Coke	7.79	12.04	14.15	19.38	24.54	30.40	37.90
Natural Gas	59.87	231.38	550.54	620.67	1 193.52	1 808.65	2 689.81
Electricity	2.36	3.85	1.18	1.18	1.18	1.18	1.18
Total	**735.43**	**845.07**	**941.72**	**1 655.26**	**2 985.58**	**4 647.11**	**6 885.19**

This sector is a good candidate for the penetration of renewables such as solar energy for water heating in substitution of fossil fuels in several sub-sectors as has been shown [4].

6.3. Net energy exports revenue

6.3.1. Energy imports trends

Energy imports increase substantially from 735.43 PJ in 1999 to 6,855.19 PJ by 2025 as shown in Table 6.19, and Figure 6.16. This represents an average annual growth rate of 8.98 percent.

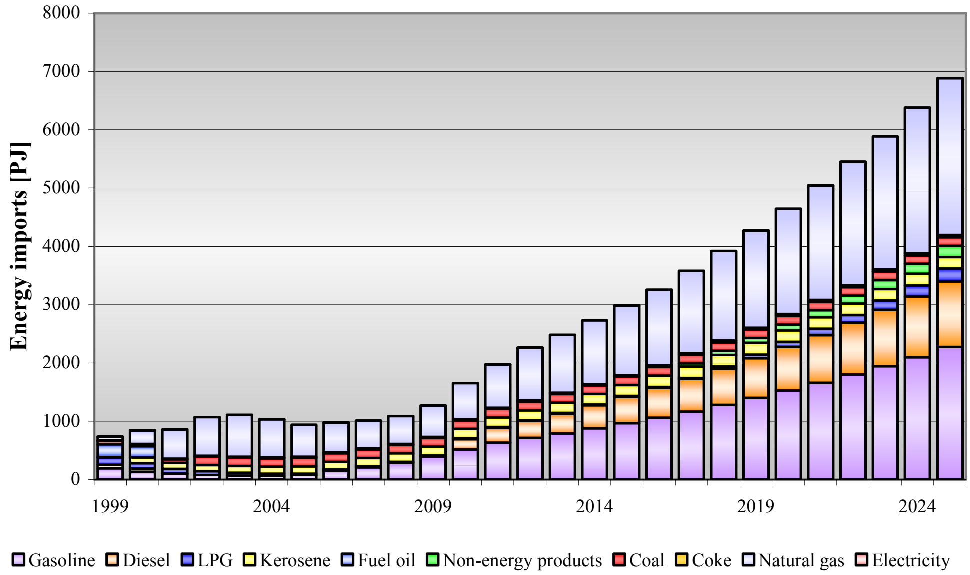

Figure 6.16 Energy and non-energy products imports (Reference case).

The leading products are natural gas, gasoline and diesel. Natural gas grows at an average annual growth rate of 15.76 percent along the projection period, while gasoline and diesel grow at average annual growth rates of 9.9 and 12.11 percent, respectively. LPG imports grow at an average annual growth rate of 2.1 percent showing a decreasing pattern that reaches its lower value in 2008; after this year starts to increase and by 2025 almost duplicates its 1999 value. This behavior can be explained in terms of two of our assumptions, first all the existing refining and fractionating capacity is operative and second population growth is the driving element for LPG demand.

Fuel oil accounted for 29.55 percent of all net imports in 1999 and 22.19 percent by 2000, after this last year imports go to zero and remain at this level for the rest of the period. This pattern could change as a result of the requirements of low sulfur fuel oil due to environmental regulation reasons and to the change in the slant of the refined oil products resulting of the completion of the reconfiguration program of the country's refining system.

Besides gasoline, the most substantial change relates to the increased gas imports that contribute 8.14 percent in 1999 (59.87 PJ) to 39.07 percent by 2025 (2,689.81 PJ). Kerosene imports (mainly, jet fuel) will increase fast along the projection period with an average annual growth rate of 14.72 percent. This calls, again the attention to a increasing dependency from aboard oil derivatives; the same consideration will apply to all refined products, a is the case of the non-energy products which will grow from zero PJ in 1999 to 191.99 PJ by 2025 with an average annual growth rate of 59.66 percent.

Coal, thermal and metallurgical will increase also due to requirements of the iron and steel industry as well as those associated with the shifting from fuel oil to imported coal in the dual power plants. The expected average annual growth rate for coal is 3.39 percent along the entire period. Coal imports will increase from 61.63 PJ in 1999 to 146.75 percent in 2025.

Coke imports will grow, at an average annual growth rate of 6.27 percent, from 7.79 PJ in 1999 to 37.90 PJ by 2025. Finally, electricity imports will remain small and, as matter of fact, they will decrease, at an average annual growth rate of 2.64 percent, from 2.18 PJ in 1999 to 1.18 PJ by 2025.

6.3.2. Energy imports trends

Total energy exports projections pass from 3,730.68 PJ in 1999 to 4,806.6 PJ by 2025 (Table 6.20 and Figure 6.17) with an average annual growth rate of 0.98 percent. Crude oil exports will continue to be the most important energy export (on the average a 94.48 percent of the total energy exports), in 1999 crude oil exports account for 3,396.07 PJ and is projected, by 2025, to arose to 4,519.78 PJ in the reference case; which means an average annual growth rate of 1.11 percent. Natural gas losses market share in the exports (from 1.32 percent in 1999 to 0.12 percent in 2025) at an average annual growth rate of 7.96 percent. However, the natural gas entire picture, imports and exports, will change if the investments in natural gas extraction, processing and fractionating capacities commented in section 5.1.2 become real.

Table 6.20 Energy and non-energy products exports (Reference case)

	1999 PJ	2000 PJ	2005 PJ	2010 PJ	2015 PJ	2020 PJ	2025 PJ
Crude oil	3 396.07	3 631.76	3 897.48	4 083.73	4 246.34	4 390.52	4 519.78
Natural gas	49.41	8.65	8.10	7.40	6.80	6.24	5.73
Gasoline	134.08	118.12	139.65	159.95	174.68	186.24	213.26
Diesel	18.86	9.34	20.79	21.83	22.74	23.55	24.28
LPG	5.91	7.35	4.33	4.55	4.74	4.91	5.07
Kerosene	4.80	7.50	5.35	5.63	5.88	6.11	6.31
Coke	0.02	0.05	0.03	0.03	0.03	0.03	0.04
Electricity	0.47	0.70	1.02	1.07	1.12	1.16	1.20
Non-energy products	7.48	13.25	9.90	10.39	10.83	11.22	11.59
Total	**3 617.10**	**3 796.71**	**4 086.66**	**4 294.59**	**4 473.16**	**4 629.98**	**4 787.24**

Gasoline exports grow at an average annual growth rate of 1.18 percent implying an increase from 134.08 PJ in 1999 to 213.26 PJ by 2025. Diesel exports also increase, but an average annual growth rate of 0.98 percent passing from 18.86 PJ in 1999 to 24.28 PJ by 2025.

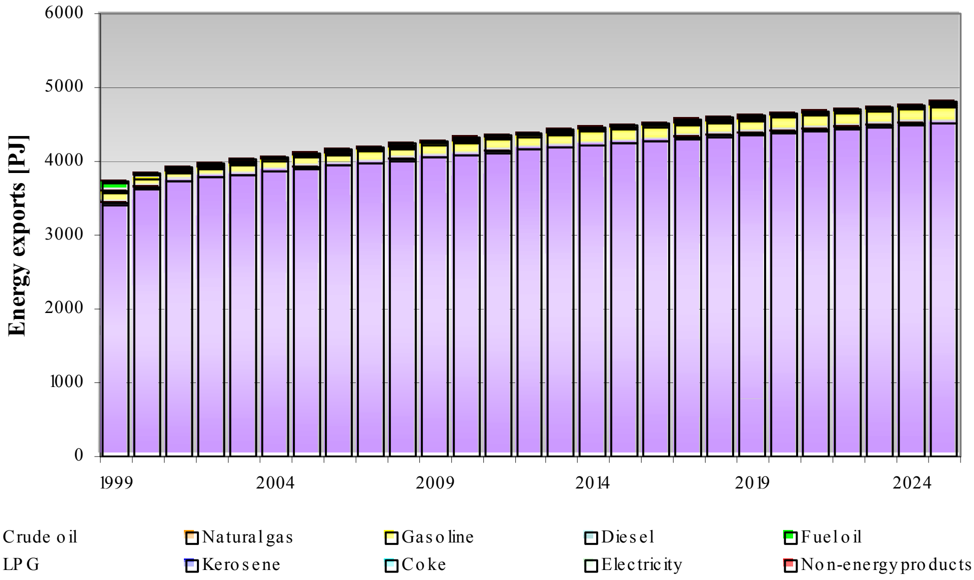

Figure 6.17 Energy and non-energy products exports (Reference case).

Electricity and coke have the highest average annual growth rates with 3.67 and 2.54 percent, respectively. However, in absolute terms their increases are small. Kerosene and non-energy products also have increases (1.06 and 1.7 percent average annual growth rates, respectively) but, as in the case of electricity and coke they are small; which means that the net balance is negative for the country. Fuel oil exports losses, at an average annual growth rate of 6.58 percent, market share, passing from 113.58 PJ in 1999 to 19.36 PJ by 2025.

In the case of the projection for LPG exports; they decrease from 5.91 PJ in 1999 to 5.07 PJ by 2025; which means a decreasing average annual growth rate of 0.59 percent.

As a matter of fact, presently the net balance of all the oil derivatives and natural gas is negative for the country and according to the results of the reference case it will continue to be negative but with a stronger dependency from foreign supply. This calls for series of studies and decisions (market analysis, investment priorities and opportunities, as well as proper actions) to decide and define if is convenient and where is convenient to go into the route of the aggregated value (jobs, better technologies, taxes, etc.) rather than the route of export raw materials.

6.3.3. Environmental results

Based on the fuel consumption results presented in previous sections, the model projects emissions releases for any given number of pollutants. The user defines the list of pollutants. For each pollutant, an emission factor needs to be provided. For this analysis, the model was configured and set up to estimate the following emissions: CO_2, CO_2 biomass, CH_4, N_2O, NO_X, SO_2, CO, NMVOC and PM.

6.3.4. Emissions of GHG's

Total CO_2 emissions (Table 6.21 and Figure 6.18) increase at an average annual growth rate of 3.41 percent between 1999 (346.1 million ton) and 2025 and reach 828.41 million ton per year by 2025. The most noticeable change in sectoral contribution comes from the transport sector whose emissions grow by 4.87 percent per year and account for 44.73 percent of the total CO_2 emissions in 2025 (370.56 million ton), up from 31.8 percent in 1999 (107.57 million ton). This is driven by the high growth in transport final energy from gasoline and diesel fuels. These fuels account for 90.12 percent of transport final energy consumption by 2025, despite the increased penetration of natural gas.

Table 6.21 CO_2 emissions by sector (Reference case)

	1999 Mton	2000 Mton	2005 Mton	2010 Mton	2015 Mton	2020 Mton	2025 Mton
Agriculture	6.43	6.36	6.80	7.70	8.88	10.47	12.56
Residential	19.62	20.47	22.10	23.62	24.73	26.09	27.37
Transport	107.57	111.91	126.99	178.15	231.01	292.62	370.56
Commercial & Public	3.84	4.29	3.04	3.50	4.02	4.59	5.22
Industrial	58.31	58.12	60.37	75.56	93.19	116.09	147.48
Power	98.19	101.01	93.15	105.86	128.84	156.66	193.07
Supply	52.13	55.70	70.75	71.14	71.49	71.82	72.14
Total	**346.10**	**357.86**	**383.20**	**465.54**	**562.15**	**678.35**	**828.41**

Mton = million ton

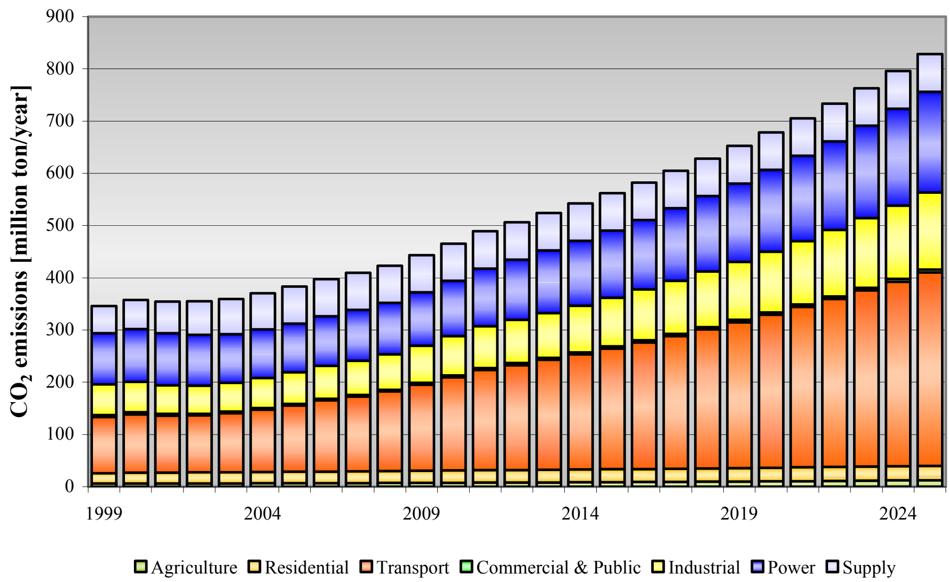

Figure 6.18 CO_2 emissions by sector (Reference case).

Electric sector CO_2 emissions grow at a below average rate of 2.63 percent per year, mostly due to the increasing reliance on natural gas. Also, there is a contribution from imported coal for the dual plants substituting fuel oil. Annual sector CO_2 emissions increase from

98.19 million ton in 1999 to 193.07 million ton by 2025. The power sector contribution slowly declines from 1999 to a low point of 93.15 in 2005, and then increases again up to the 2025 value. CO_2 emissions in some of the sectors grow at sectors average annual growth rates below average annual growth rate for the entire energy system, specifically:

- Industrial sector: 16.85 percent share (58.31 million ton) in 1999 to 17.8 percent (147.48 million ton) in 2025; an average annual growth rate of 3.63 percent; this sector shows a slight declination in its share from 1999 to a low point of 53.81 million ton in 2002, and then increases again up to the value in 2025;
- Supply sector: 15.06 percent share (52.13 million ton) in 1999 to 8.71 percent (72.14 million ton) in 2005; an average annual growth rate of 1.26 percent; even that the sector shows an increasing emissions pattern its share to the total emissions decreases systematically after 2003;
- Residential sector: 5.67 percent (19.62 million ton) in 1999 to 3.3 percent (27.37 million ton) in 2025; an average annual growth rate of 1.29 percent. This sector also shows, in absolute terms, an increasing emissions pattern but its share to the total emission decreases systematically after 2003; this behavior could be explained in terms of two aspects, one related to energy mix and the other to the lower growth rate of the population.
- Agriculture sector: 1.86 percent (6.43 million ton) in 1999 to 1.52 percent (12.56 million ton) in 2025; an average annual growth rate of 2.61 percent; and,
- Commercial and Public sector: 1.11 percent (3.84 million ton) in 1999 to 0.63 percent (5.22 million ton) in 2005; an average annual growth rate of 1.19 percent.

Table 6.22 CO_2 biomass emissions by sector (Reference case)

	1999	2000	2005	2010	2015	2020	2025
	Mton	Mton	Mton	Mton	Mton	Mton	Mton
Agriculture	0.00	0.02	0.11	0.09	0.20	0.40	0.62
Residential	27.61	27.80	28.05	28.31	28.52	28.83	29.12
Transport	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial & Public	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial	10.12	9.33	11.32	14.26	16.89	19.61	22.52
Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**37.73**	**37.15**	**39.48**	**42.66**	**45.61**	**48.84**	**52.25**

M = million

As a general result for all the sectors, the decreasing pattern of energy consumption and associated emissions in the years 1999-2003 is a result of the low economic growth of the whole economy.

Following the IPCC methodology, CO_2 emissions from the biomass consumption (firewood and sugar cane bagasse in the case of Mexico) are not added to total emission shown in Table 6.21 and Figure 6.18. However, the model allows calculating the CO_2 emission originated from the biomass consumption. Table 6.22 and Figure 6.19 show the total amount and the sectoral distribution of the CO_2 emissions originated from the use of the firewood in the residential sector for coking and water heating activities and the use of sugar cane bagasse in the sugar industry for the generation of heat process and other uses.

Total CH_4 emissions increase by 93.16 percent from 179.39 to 346.5 thousand ton over the period 1999–2025 (Table 6.23, and Figure 6.20), an average annual growth rate of 2.56 percent along the entire period. The main contribution comes from the supply sector with an increase of 2.77 percent per year (103.33 percent total growth) driven by the growth in the coal use. By 2025, the supply sector accounts for 59.76 percent of total CH_4 emissions, up from 56.77 percent in 1999. This is followed by the transport sector with a 4.92 percent per year increase, from 21.53 to 75.07 thousand ton, equivalent to a 248.62 percent total increase by the consumption of gasoline and diesel; residential sector emissions growth from 53.23 thousand ton in 1999 to 56.26 thousand ton by 2025 with an average annual growth rate of 0.21 percent. Even that the power sector is projected to have an important increase in the use of natural gas its CH_4 emissions do not grow as fast as in other sectors, power sector CH_4 emissions grow at an average annual growth rate of 3.8 percent passing from 1.26 thousand ton in 1999 to 3.3 thousand ton in 2025, however in all cases has to be take into account the Direct Global Warming Potential factor for methane and NO_X.

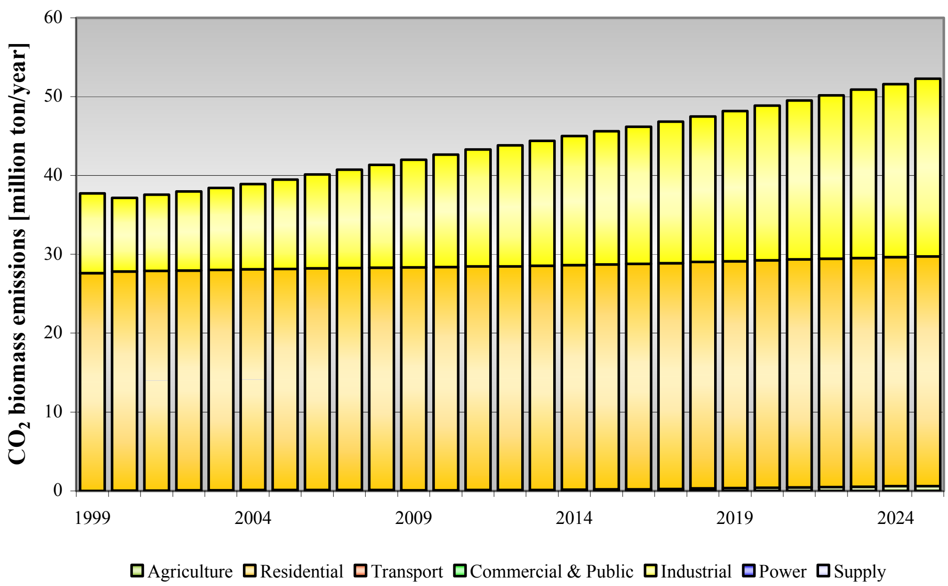

Figure 6.19 CO_2 biomass emissions by sector (Reference case).

The industrial and the Commercial and Public sectors show a similar pattern as the power sector, that is, an average annual growth rate of 2.8 and 1.19 percent, respectively, however in absolute terms their increases are small in comparison with transport and supply sector (Table 5.23). Finally, the agriculture sector grows from 0.02 thousand ton in 1999 to 1.73 thousand ton by 2025; this means an average annual growth rate of 17.91 percent along the entire period.

Table 6.23 CH_4 emissions by sector (Reference case)

	1999 kton	2000 kton	2005 kton	2010 kton	2015 kton	2020 kton	2025 kton
Agriculture	0.02	0.09	0.33	0.26	0.58	1.12	1.73
Residential	53.23	53.61	54.13	54.65	55.08	55.70	56.26
Transport	21.53	22.42	25.87	36.27	46.94	59.37	75.07
Commercial & Public	0.05	0.06	0.04	0.05	0.05	0.06	0.07
Industrial	1.45	1.42	1.37	1.62	1.92	2.35	2.97
Power	1.26	1.33	1.41	1.71	2.15	2.66	3.33
Supply	101.84	97.69	116.93	136.80	156.36	178.60	207.06
Total	**179.39**	**176.61**	**200.07**	**231.35**	**263.09**	**299.87**	**346.50**

k = thousand

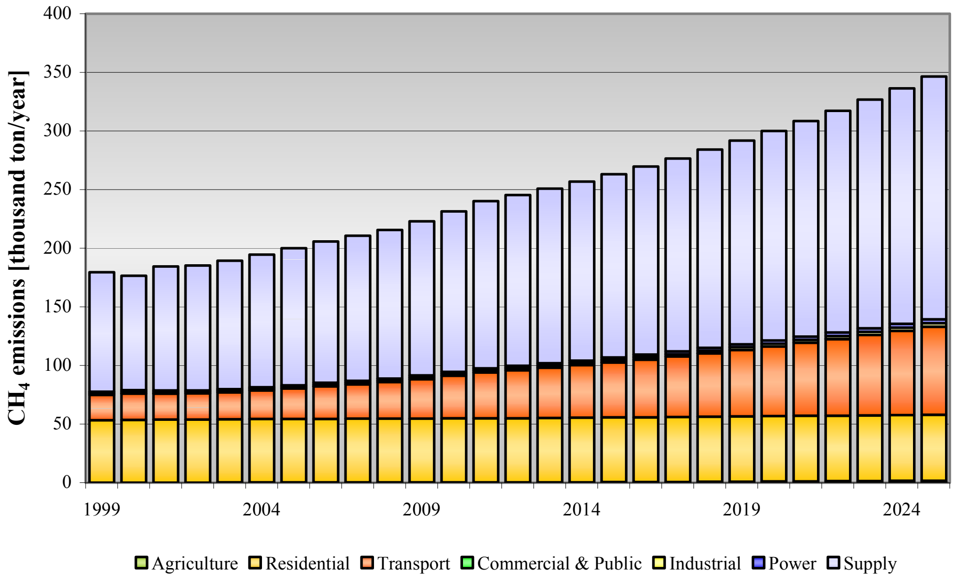

Figure 6.20 CH_4 emissions by sector (Reference case).

Total N_2O emissions increase by 105.54 percent from 3,425.5 to 7,040.8 ton over the period 1999–2025, and grow at an average annual growth rate of 2.81 percent (Table 6.24, and Figure 6.21). N_2O emissions are dominated by transport sector. Transport represents the 31.2 percent of total N_2O emissions in 1999 (1,068.65 ton) and 52.22 percent in 2025 (3,676.85 ton); an average annual growth rate of 4.87 percent, equivalent to a 244.07 percent total increase. Transport sector is followed by the residential sector with an average annual growth rate 0.33 percent, from 1,184.82 ton in 1999 to 1,291.78 ton by 2025. Industrial sector also shows an important increase with an average annual growth rate of 4.19 percent, from 285.4 tons in 1999 to 829.25 ton by 2025, followed the power (553.92 ton in 1999 and 767.56 ton in 2025) and supply (260.29 ton in 1999 and 336.03 ton in 2025) sectors with an average annual growth rate of 1.26 and 0.99 percent, respectively. The agriculture sector also increases its N_2O emission with an average annual growth rate of 3.53 percent, passing from 36.92 ton in 1999 to 91.08 by 2025. Finally, the commercial and public sector increases its emissions at an average annual growth rate of 1.19 percent.

Table 6.24 N_2O emissions by sector (Reference case)

	1999 ton	2000 ton	2005 ton	2010 ton	2015 ton	2020 ton	2025 ton
Agriculture	36.92	37.23	42.42	46.84	57.13	72.34	91.08
Residential	1 184.82	1 198.23	1 217.44	1 236.53	1 251.29	1 272.16	1 291.78
Transport	1 068.65	1 105.88	1 260.33	1 767.83	2 292.64	2 904.15	3 676.85
Commercial & Public	35.51	39.62	28.06	32.35	37.12	42.37	48.25
Industrial	285.40	296.28	327.57	428.74	535.14	662.37	829.25
Power	553.92	555.37	586.86	594.32	637.40	693.67	767.56
Supply	260.29	255.96	328.30	330.16	331.92	333.79	336.03
Total	**3 425.50**	**3 488.58**	**3 790.99**	**4 436.77**	**5 142.63**	**5 980.85**	**7 040.80**

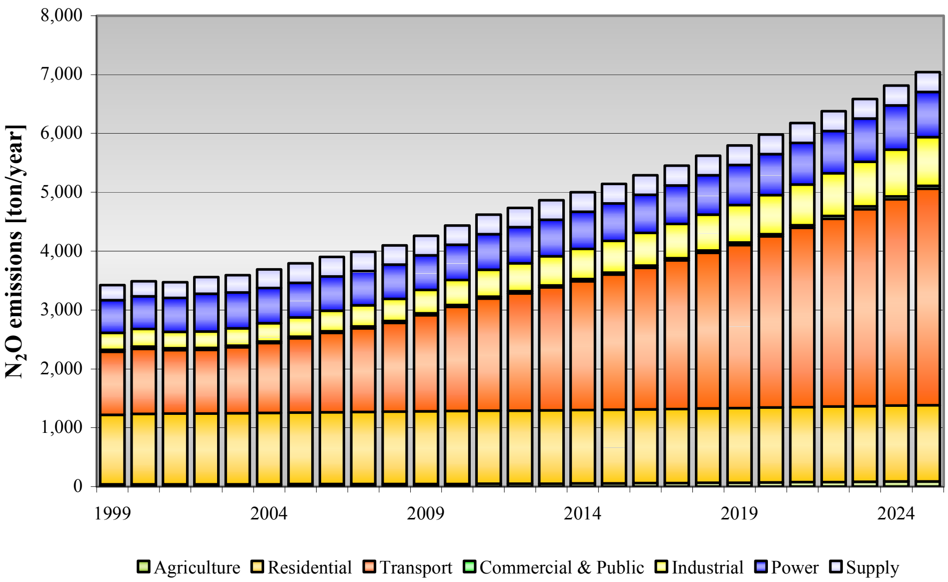

Figure 6.21 N_2O emissions by sector (Reference case).

National NO_X emissions (Table 6.25 and Figure 6.22) are expected to grow at an average rate of 4.37 percent per year from 1.52 to 4.61 million ton over the period 1999–2025. Transport sector is the largest contributor with 66.84 percent in 1999 (1,013.59 thousand ton) and

73.62 percent in 2025 (3,392.1 thousand ton) of total NO_X emissions, which implies a 234.66 percent increase for the projection period. Overall, transport-related NO_X emissions grow by 4.76 percent per year, while power sector NO_X emissions are expected to grow at 4.28 percent average annual growth rate passing from 281.85 thousand ton in 1999 to 837.41 thousand ton by 2025, this means an increase of 197.11 percent along the period. Industrial sector also shows an important increase, 137.96 percent along the period, with an average annual growth rate of 3.39 percent and absolute values of 82.79 thousand ton in 1999 and 197.01 thousand ton by 2025.

Agriculture sector emissions grow at an average annual growth rate of 2.61 percent passing from 5.99 thousand ton in 1999 to 11.69 thousand ton by 2025, which means an increase of 95.17 percent. The supply sector emissions of this pollutant also increase from 82.89 thousand ton in 1999 to 110.85 thousand ton by 2025 with an average annual growth rate of 1.12 percent. Commercial and public sector emissions increase at an average growth rate of 1.19 percent, from 4.26 thousand ton in 1999 to 5.79 thousand ton by 2025, a 35.9 percent increase in 2025 with respect to 1999. The residential sector increase its emissions at an average annual growth rate of 0.61 percent, 44.99 thousand ton in 1999 and 52.71 thousand ton by 2025, a 17.16 percent increase.

Table 6.25 NO_X emissions by sector (Reference case)

	1999 kton	2000 kton	2005 kton	2010 kton	2015 kton	2020 kton	2025 kton
Agriculture	5.99	5.92	6.33	7.17	8.27	9.74	11.69
Residential	44.99	45.84	47.41	48.89	50.01	51.41	52.71
Transport	1 013.59	1 059.52	1 161.61	1 628.92	2 113.05	2 677.72	3 392.10
Commercial & Public	4.26	4.76	3.37	3.88	4.46	5.09	5.79
Industrial	82.79	82.11	83.88	104.21	127.11	156.60	197.01
Power	281.85	301.99	380.87	457.24	561.25	681.48	837.41
Supply	82.89	85.49	109.08	109.57	110.00	110.42	110.85
Total	**1 516.36**	**1 585.64**	**1 792.55**	**2 359.88**	**2 974.14**	**3 692.46**	**4 607.56**

k = thousand

As in the case of the CH_4 emissions and given the important increments in the NO_X emissions for some of the sectors, proper care must paid to the mead and long term effects of the Direct Global Warming Potential of this pollutant.

6.3.5. Emissions of CO, SO_2, PM and NMVOC

The CO emissions (Table 6.26 and Figure 6.23) increase from 11,009.8 thousand ton in 1999 to 31,571.7 thousand ton in 2025, representing an increase of 186.76 percent along the period with an average annual growth rate of 4.14 percent.

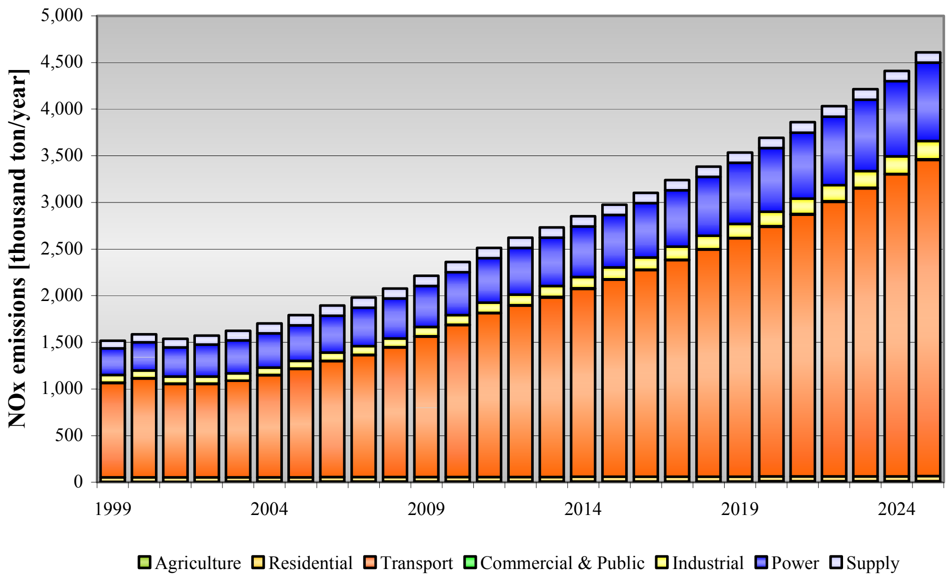

Figure 6.22 NO_X emissions by sector (Reference case).

Table 6.26 CO emissions by sector (Reference case)

	1999	2000	2005	2010	2015	2020	2025
	kton	kton	kton	kton	kton	kton	kton
Agriculture	1.42	2.44	6.48	5.59	11.03	20.34	30.76
Residential	2 521.41	2 538.70	2 562.10	2 585.97	2 605.82	2 634.22	2 660.20
Transport	8 121.58	8 450.64	9 787.96	13 720.16	17 748.72	22 439.19	28 363.27
Commercial & Public	0.57	0.63	0.45	0.52	0.59	0.68	0.77
Industrial	36.17	31.39	34.33	43.88	54.16	66.66	82.75
Power	21.98	23.16	25.82	31.27	39.24	48.47	60.49
Supply	306.68	288.89	373.12	373.22	373.31	373.39	373.46
Total	**11 009.80**	**11 335.85**	**12 790.27**	**16 760.61**	**20 832.87**	**25 582.96**	**31 571.70**

k = thousand

Transport sector represents the main contribution, 8,121.58 thousand ton in 1999 and 28,363.27 thousand ton in 2025, therefore an increase of 249.23 percent and an average annual growth rate of 4.92 percent. Second in importance of contribution, in absolute terms, is the residential sector with 2,521.41 thousand ton in 1999 and 2,600.20 thousand ton in 2025, an average annual growth rate of 0.21 percent and a 5.5 percent increase from 1999 to 2025. In third place is the supply sector, which contributes, in absolute terms, with 306.68 thousand ton in 1999 and 373.46 thousand ton in 2025, an increase of 21.77 percent and an average annual growth rate of 0.76 percent. Next, is the industrial sector with an increase of 128.78 percent along the entire period, 36.17 thousand ton in 1999 and 82.75 thousand ton by 2025 and an average annual growth rate of 3.23 percent. The power sector contributes with an increase of 175.21 percent along the period, 21.98 thousand ton in 1999 and 60.49 thousand ton in 2025 and an average annual growth rate of 3.97 percent. The contribution of the agriculture sector also increases from 1.42 thousand ton in 1999 to 30.76 thousand ton by 2025 and an average annual growth rate of 12.56 percent. Finally, the commercial and public sector increases with an average annual growth rate of 0.77 percent passing from 0.57 thousand ton in 1999 to 0.77 thousand ton in 2025.

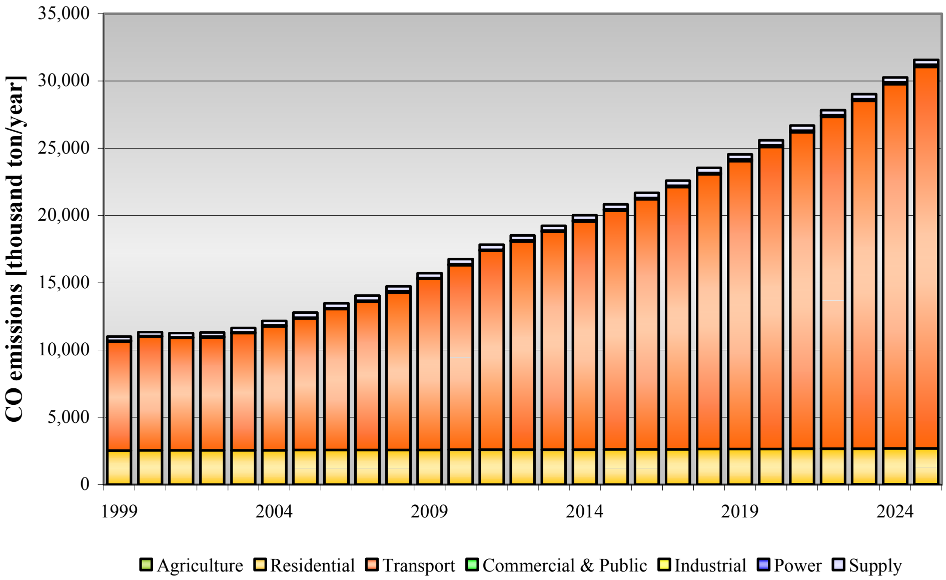

Figure 6.23 CO emission by sector (Reference case).

The SO_2 emissions (Table 6.27 and Figure 6.24) decrease from 2,347.41 thousand ton in 1999 to 1,775.35 thousand ton in 2025, representing a decrease of 24.37 percent along the period with a negative average annual growth rate of 1.07 percent. Industrial sector represents the main contribution, 442.44 thousand ton in 1999 and 1,068.51 thousand ton in 2025, therefore an increase of 141.51 percent and an average annual growth rate of 3.42 percent. Second in importance of contribution, in absolute terms, is the power sector with 1,711.17 thousand ton in 1999 and 384.69 thousand ton in 2025, a negative average annual growth rate of 5.58 percent and a 77.52 percent decrease from 1999 to 2025. Clearly, this is a result of the strong penetration of the natural gas in the energy mix of this sector. The supply sector, contributes, in absolute terms, with 118.03 thousand ton in 1999 and 153.10 thousand ton in 2025, an increase of 29.72 percent and an average annual growth rate of 1.01 percent. The transport sector with an increase of 139.48 percent, 54.68 thousand ton in 1999 and 130.95 thousand ton by 2025, and an average annual growth rate of 3.42 percent. The agriculture sector contributes with an increase of 85.78 percent along the period, 18.41 thousand ton in 1999 and 34.20 thousand ton in 2025 and an average annual growth rate of 2.41 percent. The contribution of the residential sector also increases from 1.65 thousand ton in 1999 to 2.48 thousand ton by 2025 and an average annual growth rate of 1.59 percent. Clearly, the low growth in the residential sector is a result of the substitution of LPG by natural gas and the contribution of the renewables substituting LPG. Finally, the commercial and public sector increases with an average annual growth rate of 1.19 percent passing from 1.05 thousand ton in 1999 to 1.42 thousand ton in 2025.

The PM emissions (Table 6.28 and Figure 6.25) increase from 323.2 thousand ton in 1999 to 484.26 thousand ton in 2025, representing an increase of 49.83 percent along the period with an average annual growth rate of 1.57 percent. Transport sector represents the main contribution, 59.54 thousand ton in 1999 and 208.07 thousand ton in 2025, therefore an increase of 249.48 percent along the entire period and an average annual growth rate of 4.93 percent. Second in importance of contribution, in absolute terms, is the industrial sector with 79.71 thousand ton in 1999 and 141.79 thousand ton in 2025, an average annual growth rate of 2.24 percent and a 77.88 percent increase from 1999 to 2025. In third place comes the supply sector, which contributes with 86.46 thousand ton in 1999 and 105.85 thousand ton in 2025, an increase of 22.42 percent and an average annual growth rate of 0.78 percent.

Table 6.27 SO_2 emissions by sector (Reference case)

	1999 kton	2000 kton	2005 kton	2010 kton	2015 kton	2020 kton	2025 kton
Agriculture	18.41	18.15	19.16	21.80	24.85	28.84	34.20
Residential	1.65	1.73	1.94	2.12	2.24	2.37	2.48
Transport	54.68	58.73	45.34	63.02	81.71	103.45	130.95
Commercial & Public	1.05	1.17	0.83	0.95	1.09	1.25	1.42
Industrial	442.44	470.93	486.05	603.79	725.80	872.45	1068.51
Power	1 711.17	1 697.01	639.99	430.69	385.20	379.41	384.69
Supply	118.03	112.15	144.47	146.37	148.25	150.37	153.10
Total	**2 347.41**	**2 359.88**	**1 337.78**	**1 268.74**	**1 369.14**	**1 538.16**	**1 775.35**

k = thousand

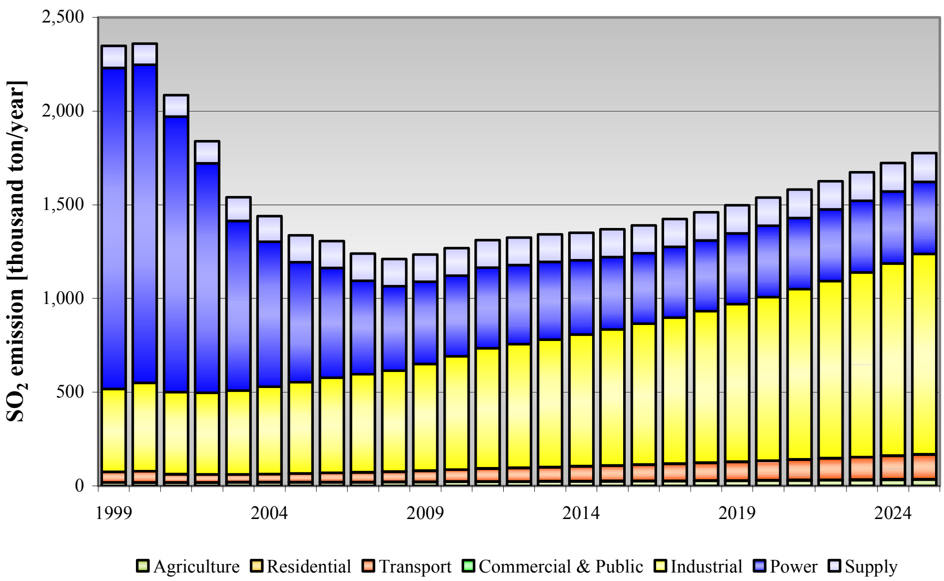

Figure 6.24 SO_2 emission by sector (Reference case).

Table 6.28 PM emissions by sector (Reference case)

	1999 kton	2000 kton	2005 kton	2010 kton	2015 kton	2020 kton	2025 kton
Agriculture	4.45	4.39	4.63	5.27	6.01	6.97	8.26
Residential	0.71	0.73	0.77	0.80	0.82	0.85	0.89
Transport	59.54	62.03	70.97	99.47	129.22	164.05	208.07
Commercial & Public	0.36	0.41	0.29	0.33	0.38	0.43	0.49
Industrial	79.71	82.92	78.28	89.75	102.26	118.59	141.79
Power	91.96	92.73	28.97	18.90	18.90	18.90	18.90
Supply	86.46	81.11	104.79	105.02	105.25	105.51	105.85
Total	**323.20**	**324.31**	**288.68**	**319.54**	**362.84**	**415.32**	**484.26**

k = thousand

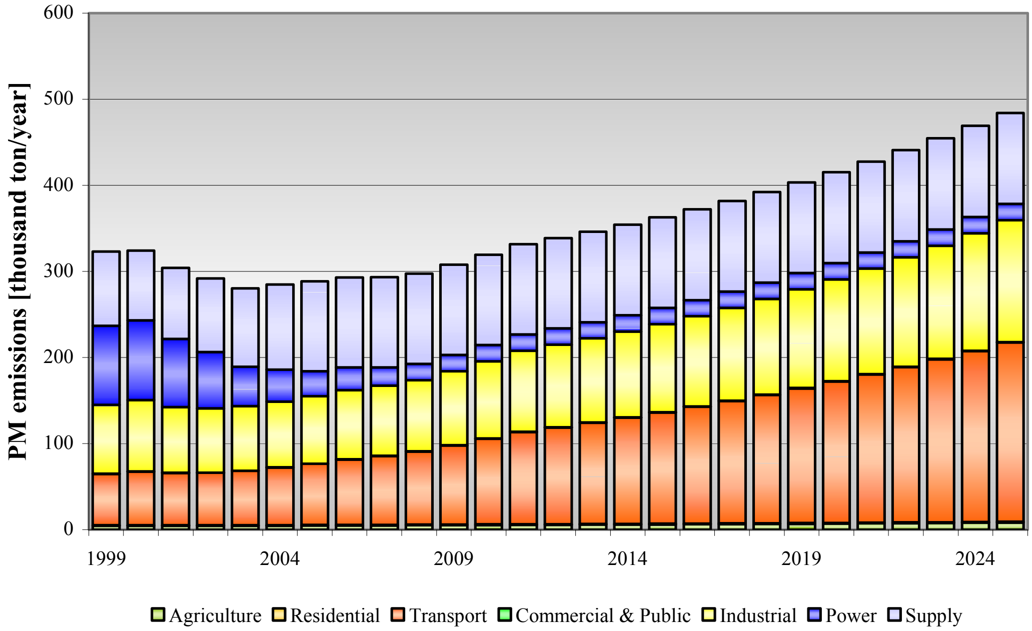

Figure 6.25 PM emissions by sector (Reference case).

The power sector shows a negative increase of 79.44 percent along the entire period, 91.96 thousand ton in 1999 and 18.90 thousand ton by 2025 and a negative average annual growth rate of 5.9 percent. Again, this is a result of the natural gas expansion in the power sector, the fuel oil substitution by imported coal and the emission controls in the dual power plants. The agriculture sector shows an increase of 85.78 percent, 4.45 thousand ton in 1999 and 8.26 thousand ton in 2025 and an average annual growth rate of 2.41 percent. The contribution of the residential sector also increases, from 0.71 thousand ton in 1999 to 0.89 thousand ton by

2025, with an average annual growth rate of 0.87 percent. Finally, the commercial and public sector increases with an average annual growth rate of 1.19 percent passing from 0.36 thousand ton in 1999 to 0.49 thousand ton in 2025.

NMVOC emissions (Table 6.29 and Figure 6.26) are dominated by the transport sector with an average annual growth rate of 4.58 percent and an increase of 249.04 percent along the entire period (1,527.21 thousand ton in 1999 and 5,330.56 thousand ton by 2025). Second in importance of contribution, in absolute terms, is the residential sector with 152.66 thousand ton in 1999 and 161.56 by 2025 (an increase of 5.83 percent along the projection period) and an average annual growth rate of 0.22 percent. In third place is the supply sector with an increase of 22.52 percent along the projection period (54.70 thousand ton in 1999 and 67.01 thousand ton in 2025) with an average annual growth rate 0.78 percent. Industrial sector shows an increase of 161.25 percent along the entire period (10.09 thousand ton in 1999 and 26.36 thousand ton by 2025) and an average annual growth rate of 3.76 percent. The power sector also shows an oscillating pattern increasing from 6.77 thousand ton in 1999 to 16.70 thousand ton by 2025 (an increase of 146.72 percent during the projection period) and an average annual growth rate of 3.53 percent.

The agriculture sector increases, also in an oscillating pattern (from 0.44 thousand ton in 1999 to 4.19 thousand ton by 2025), with an average annual growth rate of 9.05 percent. Finally, the commercial and public sector also shows an oscillating pattern, increasing by 35.9 percent along the projection period, from 0.3 thousand ton in 1999 to 0.41 thousand ton by 2025 and with an average annual growth rate of 1.19 percent.

Table 6.29 NMVOC emissions by sector (Reference case)

	1999	2000	2005	2010	2015	2020	2025
	kton	kton	kton	kton	kton	kton	kton
Agriculture	0.44	0.56	1.06	0.99	1.69	2.86	4.19
Residential	152.66	153.76	155.29	156.83	158.10	159.91	161.56
Transport	1 527.21	1 589.06	1 839.73	2 578.58	3 335.68	4 217.24	5 330.56
Commercial & Public	0.30	0.34	0.24	0.27	0.32	0.36	0.41
Industrial	10.09	9.38	10.42	13.58	16.96	21.05	26.36
Power	6.77	7.08	7.18	8.60	10.78	13.35	16.70
Supply	54.70	51.80	66.85	66.89	66.93	66.97	67.01
Total	**1 752.18**	**1 811.97**	**2 080.77**	**2 825.74**	**3 590.46**	**4 481.75**	**5 606.81**

k = thousand

6.4. Limited gas scenario results

6.4.1. Effects on power sector

As a result of the limitation in gas supply, the expansion of the power sector changes substantially. Starting in 2009, the expansion model selects the maximum of 3 combined cycle units each year instead of 3 to 7 units per year under the reference case. The cumulative number of combined cycle units under the limited gas scenario totals 85 (44.8 GW) as compared to 118 units (62.2 GW) under the reference case.

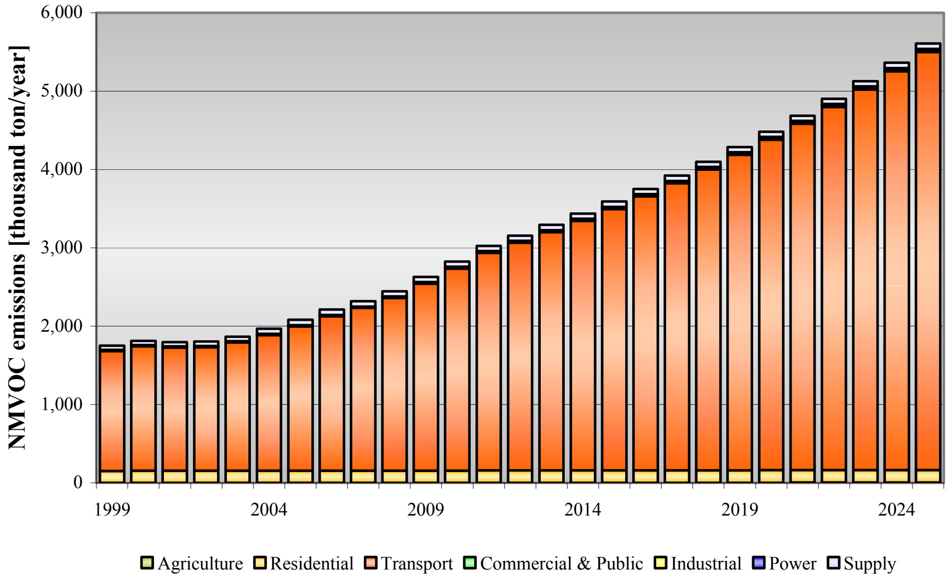

Figure 6.26 NMVOC emissions by sector (Reference case).

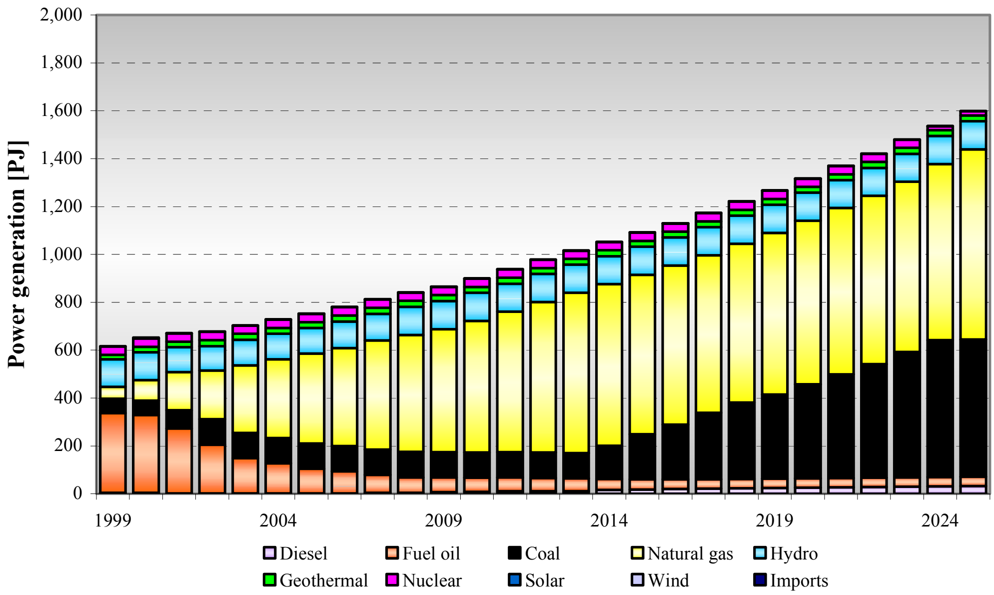

Figure 6.27 National power generation by fuel type (Limited gas case).

The effect on generation by fuel type can be seen in Figure 6.27. It is noteworthy that while the gas limitation becomes effective in 2009, the generation results don't show a significant difference until 2014. This is the year when WASP/DECADES project the first coal-fired units to come on-line. During 2009 to 2013, even though that there are 4 combined cycle units less than in the reference case, the new coal units are not needed until 2014. Starting in 2014, the model projects between 4 and 6 coal-fired units to come on-line each year, with a total of 57 coal units or 17.7 GW. Correspondingly, coal generation starts to increase quickly from 60.6 PJ in 2013 to 466.4 PJ by 2025 and account for 29 percent of total power generation. The increased coal generation essentially replaces up to 409 PJ of gas-fired generation by 2025 (Figure 6.28). The share of natural gas generation, therefore, reaches only about 56 percent as compared to 82 percent under the reference case.

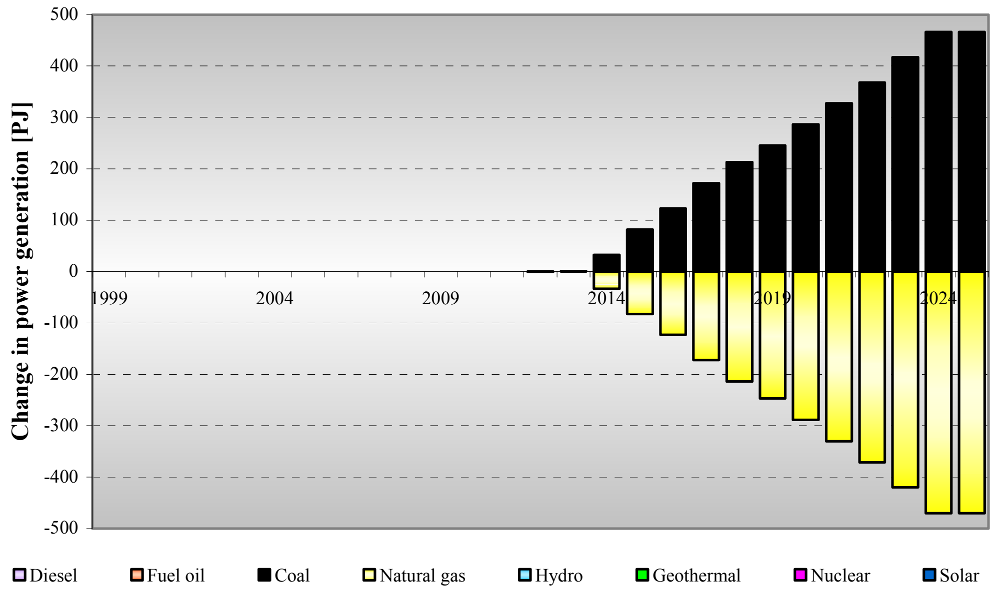

Figure 6.28 Change in power generation by fuel type (Limited gas case minus Reference case).

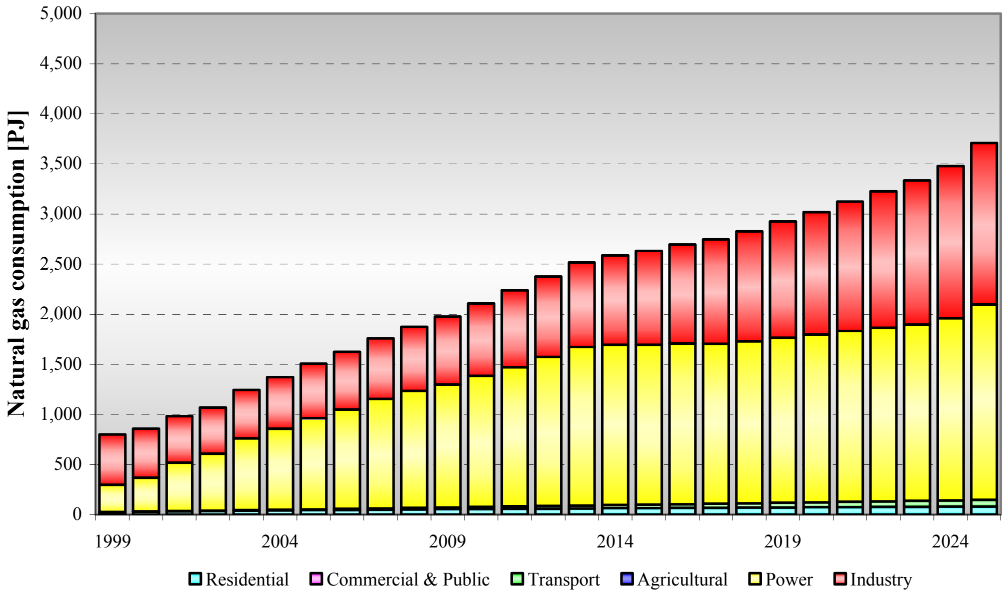

Figure 6.29 Natural gas consumption by sector (Limited gas case).

The lower gas generation noticeably slows the growth in total natural gas consumption. Gas consumption is expected to grow to 3,928 PJ, down from 4,769 PJ in the reference case. This reduction of 841 PJ in essentially power sector gas demand is shown in Figure 6.29. While under the reference case, the power sector accounts for about 63 percent of total natural gas demand, under the limited gas scenario, this is down to 55 percent.

6.4.2. Effects on supplies

In response to the reduction in gas demand for power generation, the need for natural gas imports declines. While approximately 2775 PJ of gas has to be imported in the reference case by 2025, imports are down to 1985 PJ in this scenario. As Figures 6.30 and 6.31 shows the additional coal-fired generation cannot address the immediate-term import needs. Imports are substantially reduced only starting in 2014. The decrease of 790 PJ by 2025 is equivalent to a 28 percent reduction of natural gas imports (Figure 6.31). At US$709.58 billion in net present value, total economic system cost is higher than under the reference case, that is, an incremental cost of US$2.17 billion.

6.4.3. Effects on emissions

Not surprisingly, the shift from gas to coal comes at an environmental cost. Atmospheric emissions are projected to increase under the limited gas scenario. Figures 6.32 and 6.33 show, for example, the changes in NO_X and CO_2 emissions when compared to the reference case.

Power sector emissions of NO_X are forecast to reach about 989,590 ton by 2025, which is about 152,180 ton or 18.17 percent higher than under the reference case in 2025. In essence, the rest of the sectors do not change their contribution to the NO_X emissions in comparison with the reference case.

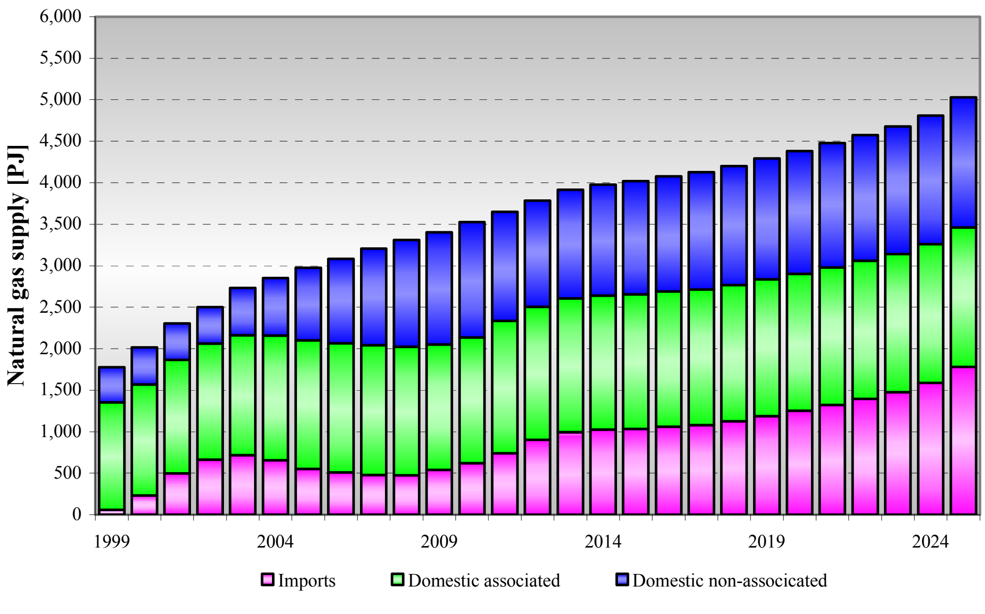

Figure 6.30 Natural gas supply (Limited gas case).

Emissions of CO_2 exhibit a similar behavior (Figure 6.33). Under the limited gas scenario, power sector emissions grow to 238.69 million ton of CO_2 while total national emissions reach 874.26 million ton. This is an increase of about 45.62 million ton over the reference case, equivalent to a 23.63 percent increase in power sector emissions or 5.22 percent of national CO_2 emissions.

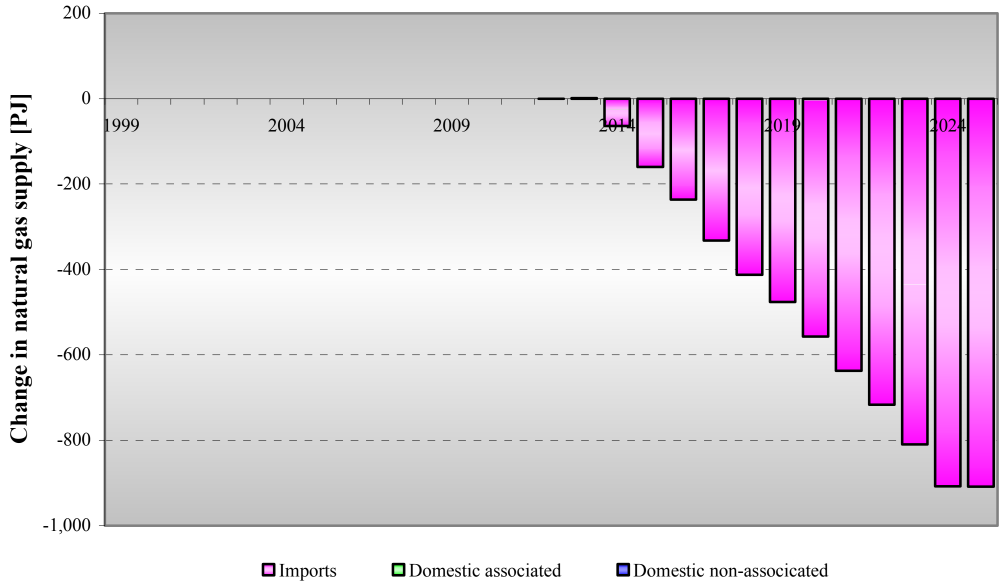

Figure 6.31 Change in natural gas supply (Limited gas case minus Reference case).

Emission of N_2O exhibit an increasing behavior. All the sectors show, up to 2020, almost the same values for the emissions as in the reference case. After 2020 the residential, transport and industrial sectors exhibit very small amounts of this emissions. However, the exception is the power sector (Figure 5.34), which increases its N_2O emissions. Up to 2013 the reference case and the limited gas case show the same value for the N_2O emissions from the power sector and from 2014 up to 2025 the N_2O emissions of the power sector in the limited gas case grow systematically from 619.8 ton up to 2,642.35 ton. This is an increase of 1,874.8 ton over the reference case, equivalent to 3.44 times de value in 2025 for the reference case or 26.63 percent of national N_2O emissions. Again, this is an effect of the reduction of natural gas for the power sector and the increasing participation of the imported coal in the sector under the limited gas case.

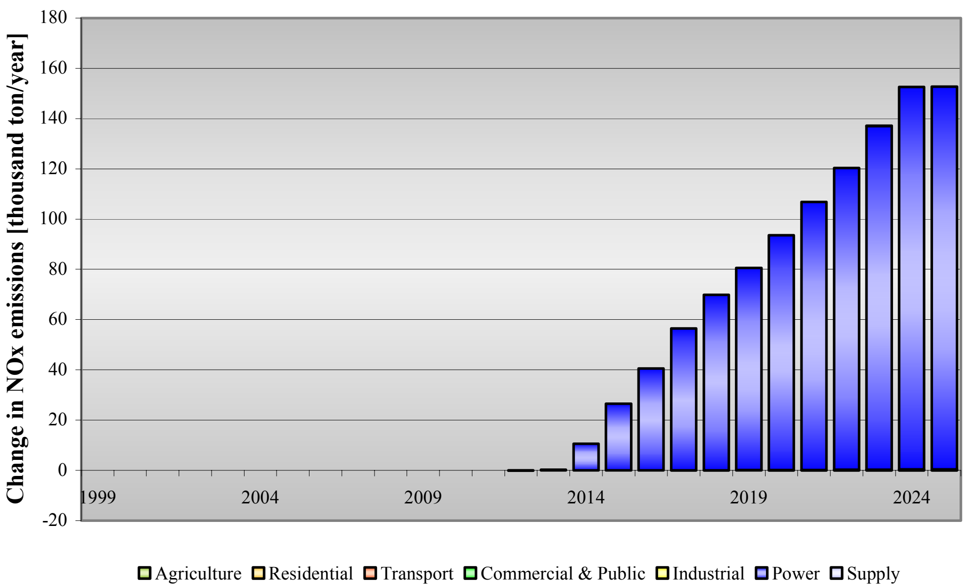

Figure 6.32 Change in NO_X emissions by sector (Limited gas case minus Reference case).

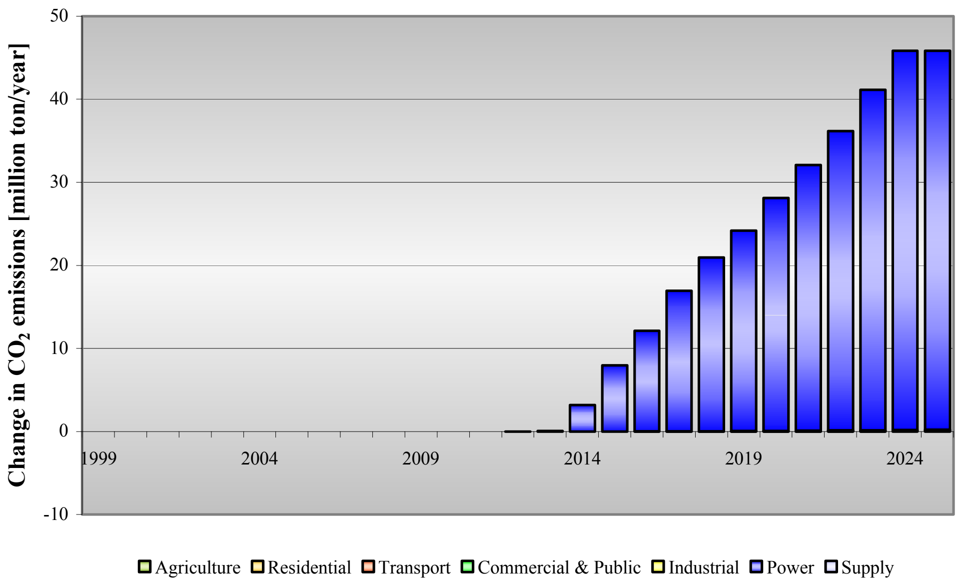

Figure 6.33 Change in CO_2 emissions by sector (Limited gas case minus Reference case).

Under the limited gas case, power sector SO_2 emissions are forecasted to increase 113,910 tons by 2025 (Figure 6.35) with respect to the reference case. It represents an increment of 29.61 percent in the power sector SO_2 emissions and an increment of 6.42 percent in the total national SO_2 emissions. This effect starts on the year 2014, year in which the coal units expansion initiate operation reducing the number of installed combine cycle units in the expansion of the power sector. Also, there is a small contribution to the SO_2 emissions coming from the industrial sector changing energy mix as a result of the price competition between fuels. Looking at the year 2025 results, limited gas case exhibits an increment in its total national emissions of SO_2 of 119,260 ton with respect to the reference case.

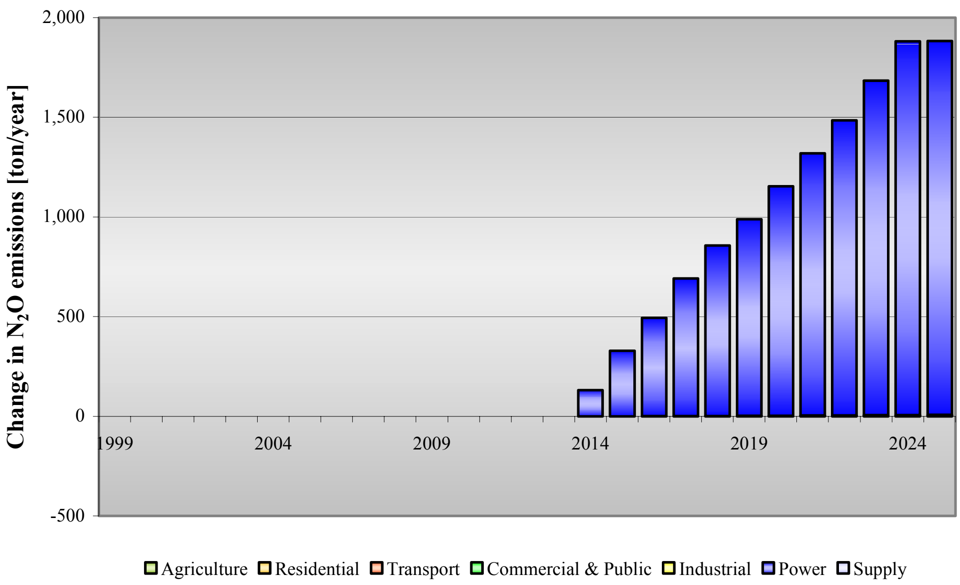

Figure 6.34 Change in N_2O emissions by sector (Limited gas case minus Reference case).

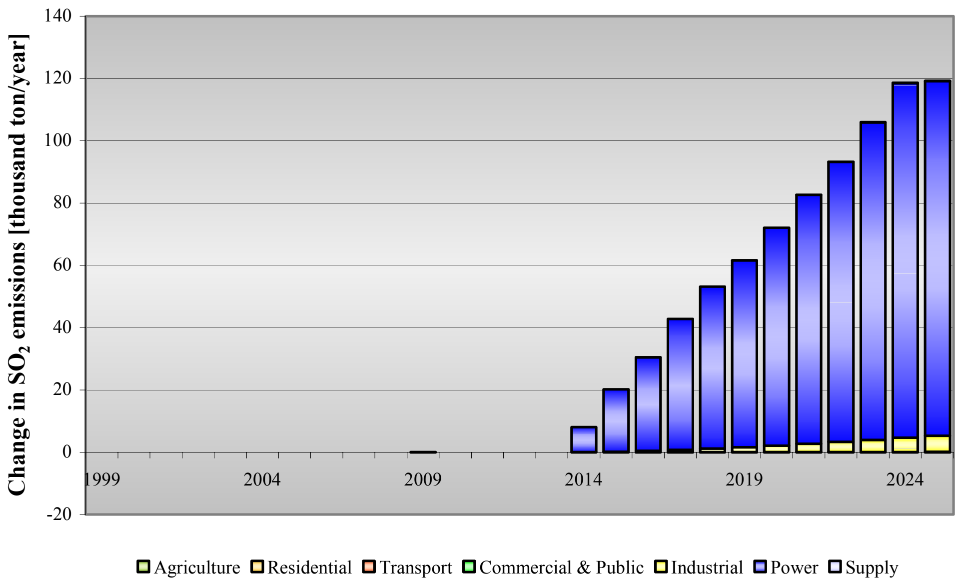

Figure 6.35 Change in SO_2 emissions by sector (Limited gas case minus Reference case).

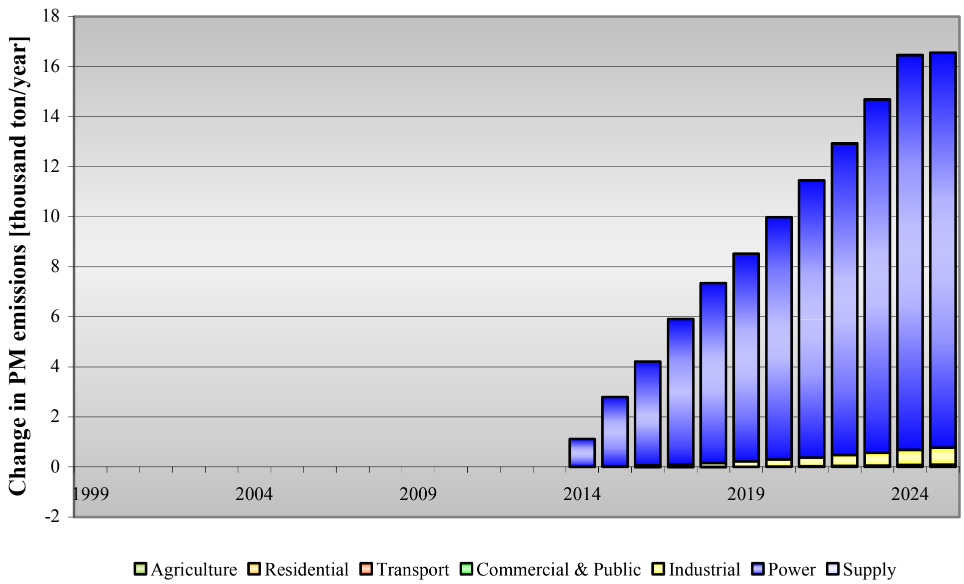

Figure 6.36 Change in PM emissions by sector (Limited gas case minus Reference case).

Total emissions of PM are forecasted to increase to 500,820 ton by year the 2025. The power sector will increase its contribution of PM emissions by 15,770 tons in the year 2025 (Figure 6.36) with respect to the reference case; this represents an increase of 83.44 percent in the power sector PM emissions and a 3.26 percent increase in the total national PM emissions in the year 2025. As in the case of the other pollutants, the increase of the power sector PM emissions starts in year 2014 as a result of the introduction of coal power units in substitution of part of the combined cycle gas-fired units in the expansion of the sector.

6.5. Nuclear scenario results

6.5.1. Effects on power sector

Because of the large capacity of the nuclear unit, the expansion schedule is slightly affected starting in 2001 even though the unit is not coming on-line until 2012. This leads to some minor changes in generation and fuel consumption in the power sector between 2001 and 2011 as presented in Figure 6.37.

Specifically, from 2001 up to 2011 there is an additional participation of fuel oil generation, which decreases along the years and ends by 2011; hydro also participates with an additional generation, but its participation is just during the year 2001; also there is a declining reduction in the participation of natural gas in the generation along those years.

During the years 2009 to 2011 the fuel type mix in the power generation keeps the reference case structure.

When the nuclear unit does come on-line, it is base-loaded into the system and generates a constant level of 34 PJ of electricity per year equivalent to 1.5 percent of total generation in 2025 as compared to 1.1 percent under the reference case. The system-level analysis shows that nuclear replaces effectively base-loaded gas combined-cycle capacity and between 33-37 PJ of gas-fired generation.

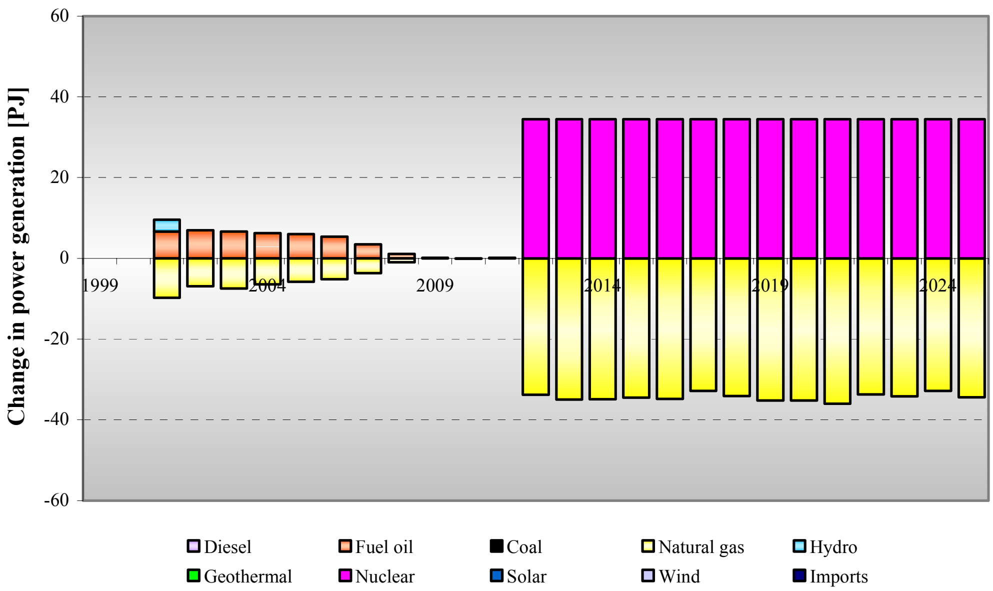

Figure 6.37 Change in power generation by fuel type (Nuclear case minus Reference case).

6.5.2. Effects on supplies

The impact on the supply side is presented in Figure 6.38. As with the previous scenarios, the shift away from gas-fired generation leads directly to a reduction in natural gas imports. In this case, gas imports are cut by 63-71 PJ or 2.3 percent by 2025.

At US$707.69 billion in net present value, total economic system cost is higher than under the reference scenario, that is, an incremental cost of US$273.4 million.

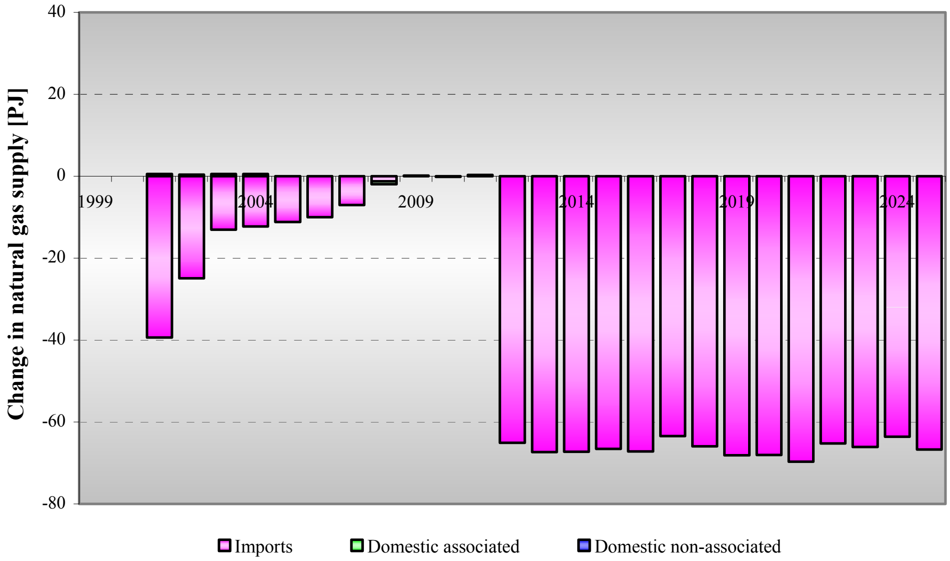

Figure 6.38 Change in natural gas supply (Nuclear case minus Reference case).

6.5.3. Effects on emissions

The minor changes in dispatch in the early years lead to small emissions increases of up to 1.2 million tons per year in 2003. But emissions are noticeable reduced starting in 2012 when the nuclear unit eventually comes on-line. For example, CO_2 emissions reductions are shown in Figure 5.39 and vary between 3.6 and 4.0 million ton per year, equivalent to a 1.9 percent reduction in power sector emissions and a 0.4 percent reduction in national emissions. Total cumulative emissions reductions are 47.5 million ton of CO_2. The cost-effectiveness of nuclear technology as a GHG mitigation technology is therefore US$5.8/ton CO_2.

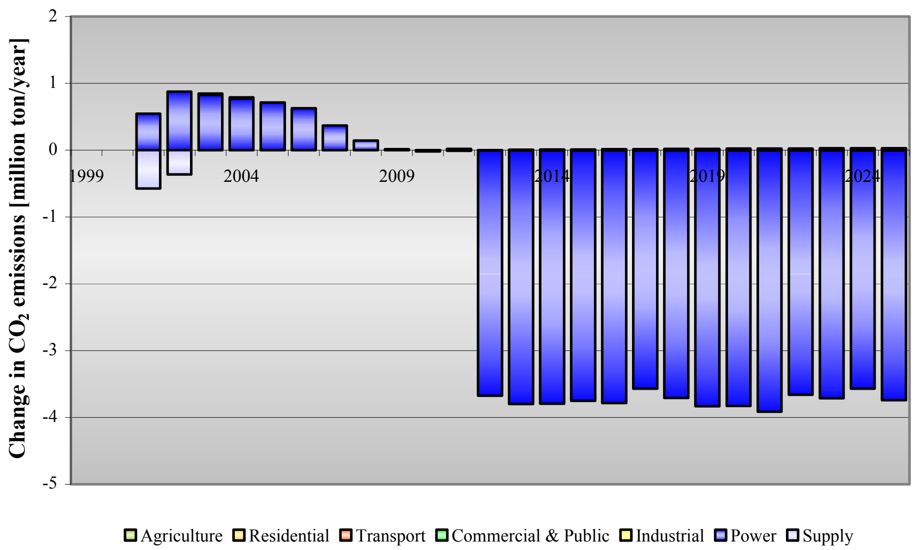

Figure 6.39 Change in CO_2 emissions by sector (Nuclear case minus Reference case).

A similar behaviour is exhibited by NO_X emission as shown in Figure 6.40. Annual reductions vary between 15,000 and 17,000 ton of NO_X. In 2025, this represents a 1.9 percent decrease in power sector NO_X emissions and a 0.3 percent decrease of total national NO_X emissions. The cumulative emissions reductions total 228,000 ton.

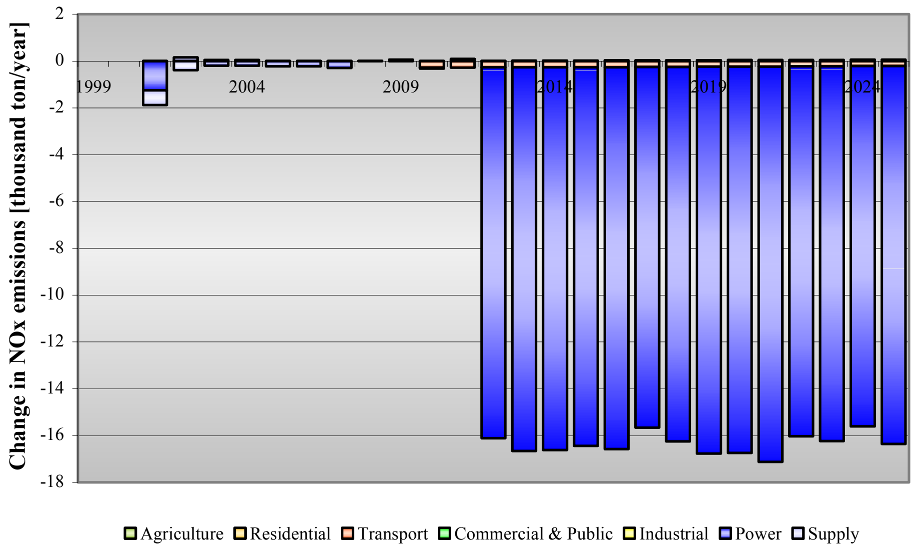

Figure 6.40 Change in NO_X emissions by sector (Nuclear case minus Reference case).

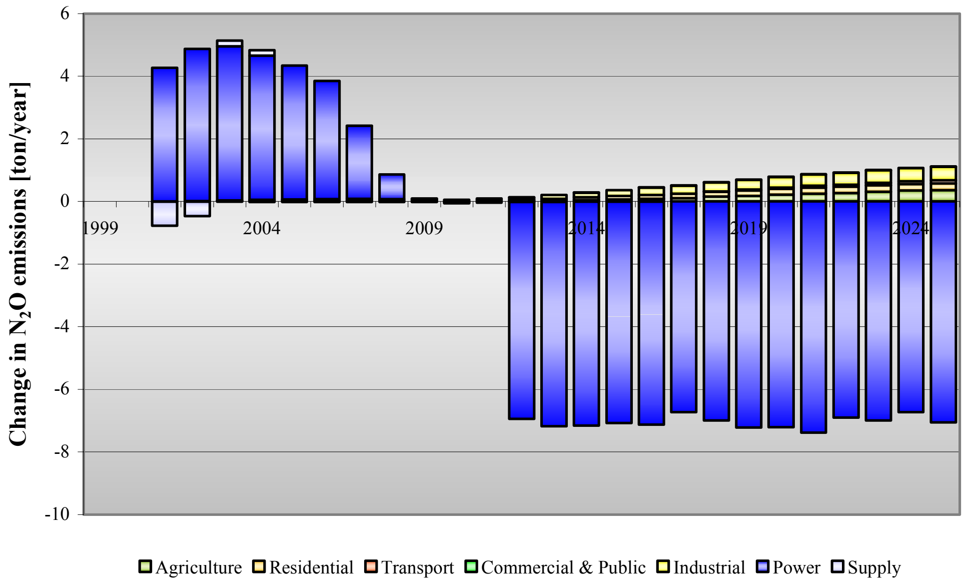

Figure 6.41 Change in N_2O emissions by sector (Nuclear case minus Reference case).

In the case of the N_2O emissions (Figure 6.41), the situation is quite similar as for the CO_2 emissions, since the fuel oil increase is reflected in an increase of N_2O emissions, natural gas reduction is shown as a reduction of N_2O emissions coming from the supply sector and the hydro participation contributes with a small amount to the N_2O emissions along the period 2001 to 2011. Total cumulative emissions reductions for the entire period are 60.27 ton. A change in the consumption of a fuel (nuclear and natural gas) changes the ratio of the other fuels and if prices for the different supply sources are different, the average price of a fuel or fuels will be different in each scenario. Since the model responds to prices changes, we will see different penetration schemes for the different sources in the end use sectors across scenarios. This explains, at least in part, the small presence of N_2O emissions coming from other sectors as can be seen in the figure

For the SO_2 emissions (Figure 6.42) and PM emissions (Figure 6.43) the situation is similar to the N_2O emissions. Fuel oil increase is reflected in an increase of emissions and natural gas reduction is shown as a reduction of emissions coming from the supply sector. Total cumulative emissions of SO_2 and PM for the entire period are 242,790 ton and 14,320 ton, respectively.

6.6. Renewables scenario results

6.6.1. Effects on power sector

Because of the relative costs of wind and solar (see Chapter 4 for technology characteristics), the role of solar PV will be very limited. By 2025, solar will generate only about 1.2 PJ of electricity or 0.1 percent of total generation. This is equivalent to 195 MW of installed PV capacity. Wind, on the other side, is forecast to penetrate the market relatively rapidly and as given in Figure 6.44. This energy source is forecasted that will account for approximately 4.9 percent of total generation, that is, 78.3 PJ by 2025. At the assumed average capacity factor of 26.2 percent, about 9,500 MW of wind capacity will be needed to generate this power. Figure 6.45 shows that wind will essentially replace marginal gas-fired generation by up to 93.3 PJ (2025), that is, about 19 percent more than wind electricity. The main reason for this difference is the underlying model implementation which assumes that wind generation will be more dispersed, closer to actual loads, and therefore not subject to the transmission and distribution losses in the electric grid.

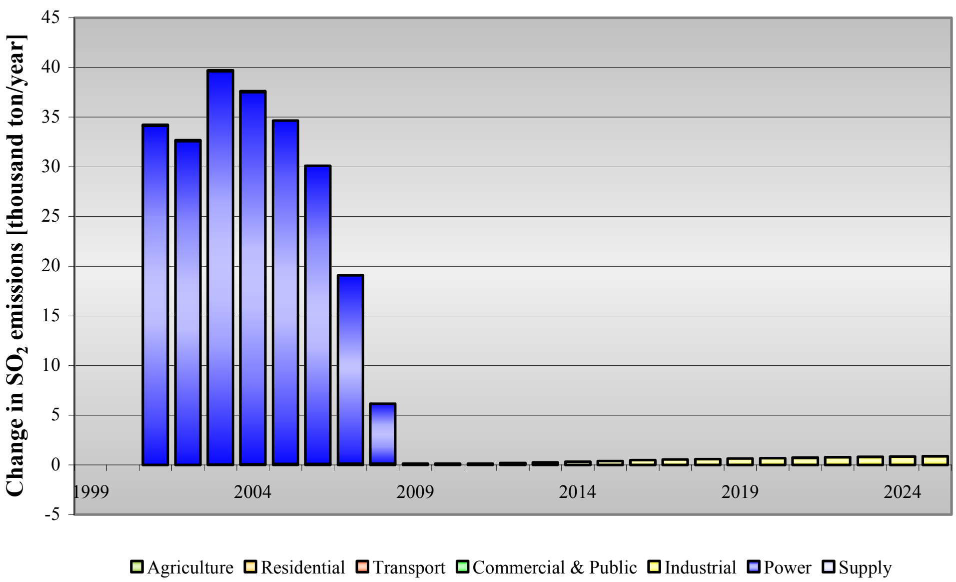

Figure 6.42 Change in SO_2 emissions by sector (Nuclear case minus Reference case).

6.7. Renewables scenario results

6.7.1. Effects on power sector

Because of the relative costs of wind and solar (see Chapter 4 for technology characteristics), the role of solar PV will be very limited. By 2025, solar will generate only about 1.2 PJ of electricity or 0.1 percent of total generation. This is equivalent to 195 MW of installed PV capacity. Wind, on the other side, is forecast to penetrate the market relatively rapidly and as given in Figure 5.44. This energy source is forecasted that will account for approximately 4.9 percent of total generation, that is, 78.3 PJ by 2025. At the assumed average capacity factor of 26.2 percent, about 9,500 MW of wind capacity will be needed to generate this power. Figure 6.45 shows that wind will essentially replace marginal gas-fired generation by up to 93.3 PJ (2025), that is, about 19 percent more than wind electricity. The main reason for this difference is the underlying model implementation which assumes that wind generation will be more dispersed, closer to actual loads, and therefore not subject to the transmission and distribution losses in the electric grid.

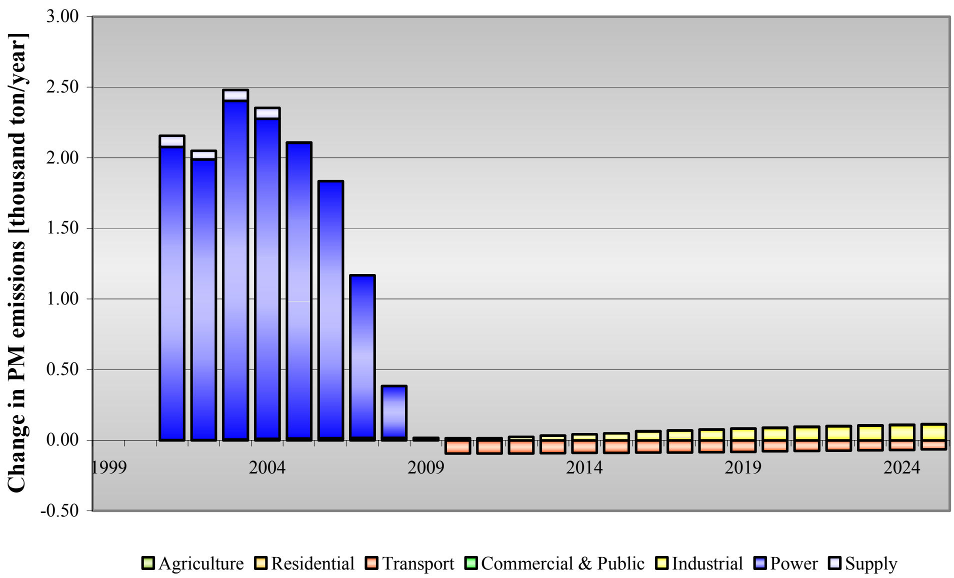

Figure 6.43 Change in PM emissions by sector (Nuclear case minus Reference case).

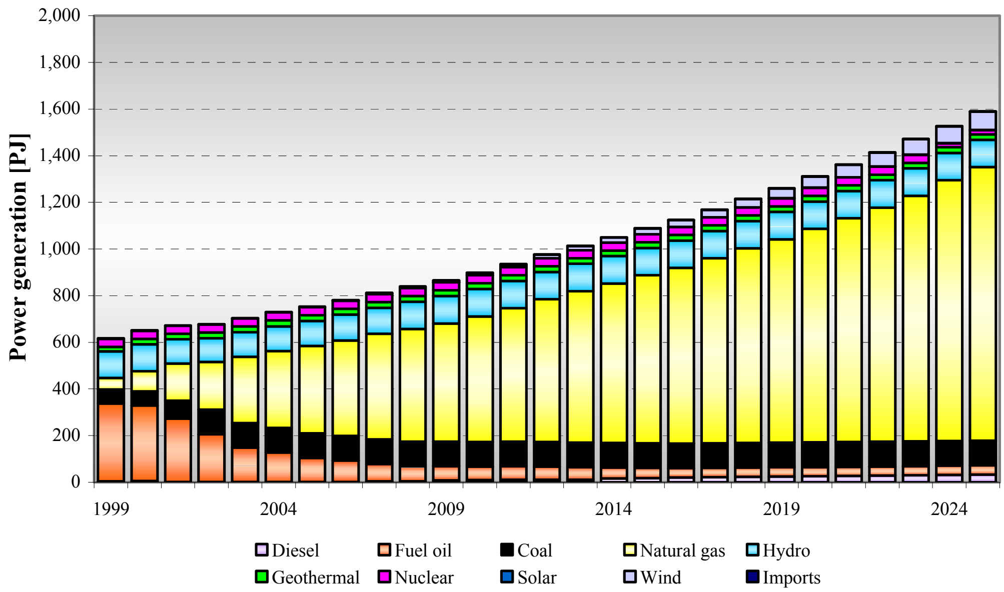

Figure 6.44 National power generation by fuel type (Renewables case minus Reference case).

6.7.2. *Effects on supplies*

Because of the change in generation mix originated by the incorporation of wind energy, the power sector will require less natural gas. This translates directly into less natural gas imports as shown in Figure 5.46. The reduction in gas imports grows as wind generation increases and reaches approximately 180 PJ by 2025. At US$707.87 billion in net present value, total economic system cost is higher than under the reference scenario, that is, an incremental cost of US$455.64 million.

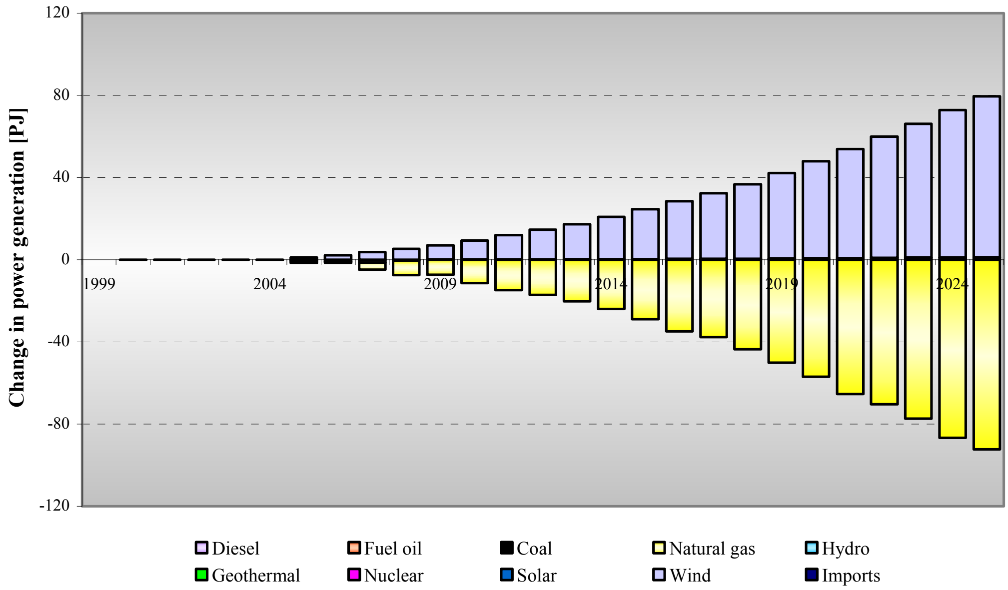

Figure 6.45 Change in power generation by fuel type (Renewables case minus Reference case).

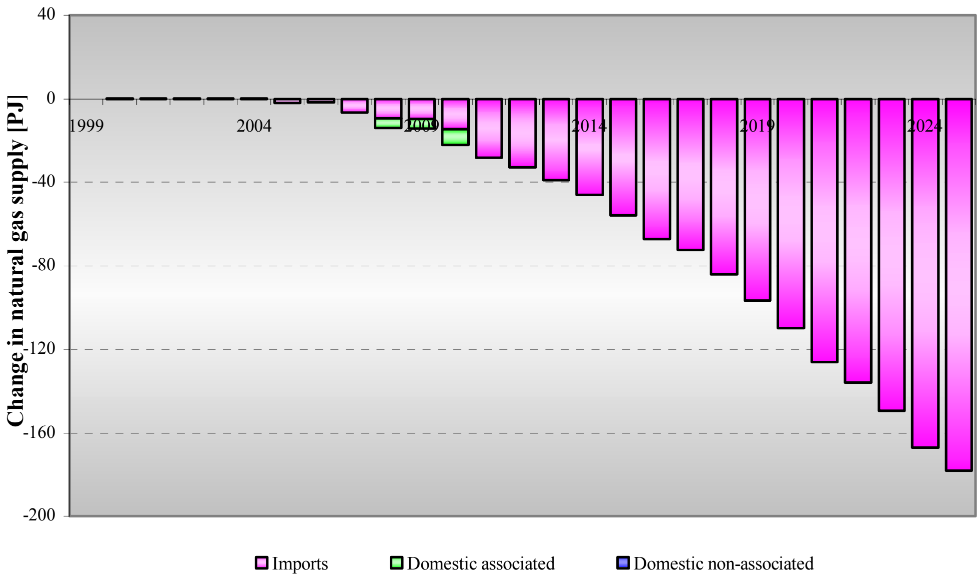

Figure 6.46 Change in natural gas supply (Renewables case minus Reference case).

6.7.3. *Effects on Emissions*

The fact that solar and wind replace electricity that is generated mostly by gas-fired combined cycle units limits the emission reduction potential of renewable technologies. NO_X emissions, for example, are 44,000 ton per year (2025) below projected reference case levels (Figure 6.47). This is equivalent to a 5.5 percent drop in power sector emissions and a 1.0 percent decrease of total national NO_X emissions. Cumulative NO_X reductions over 2005–2025 total about 351,000 ton.

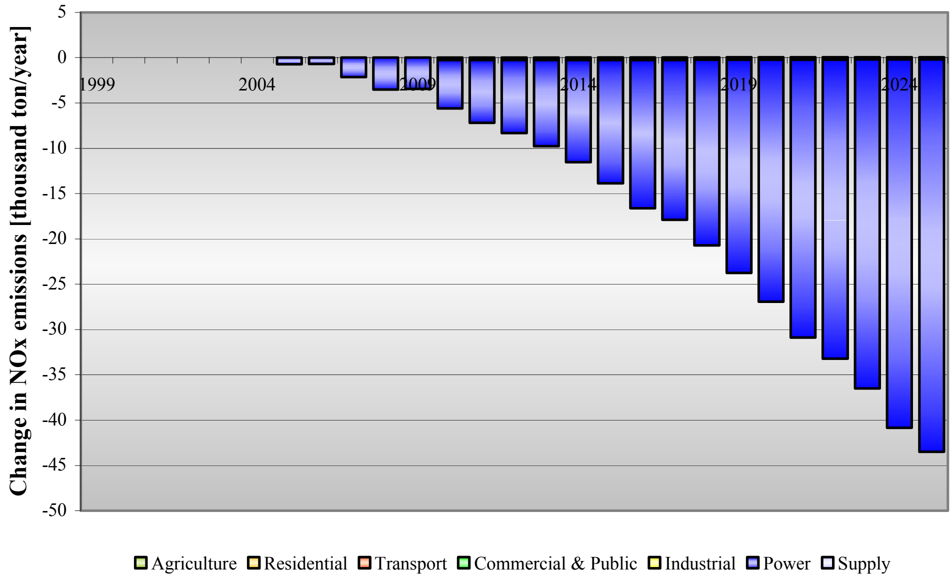

Figure6.47 Change in NO_X emissions by sector (Renewables case minus Reference case).

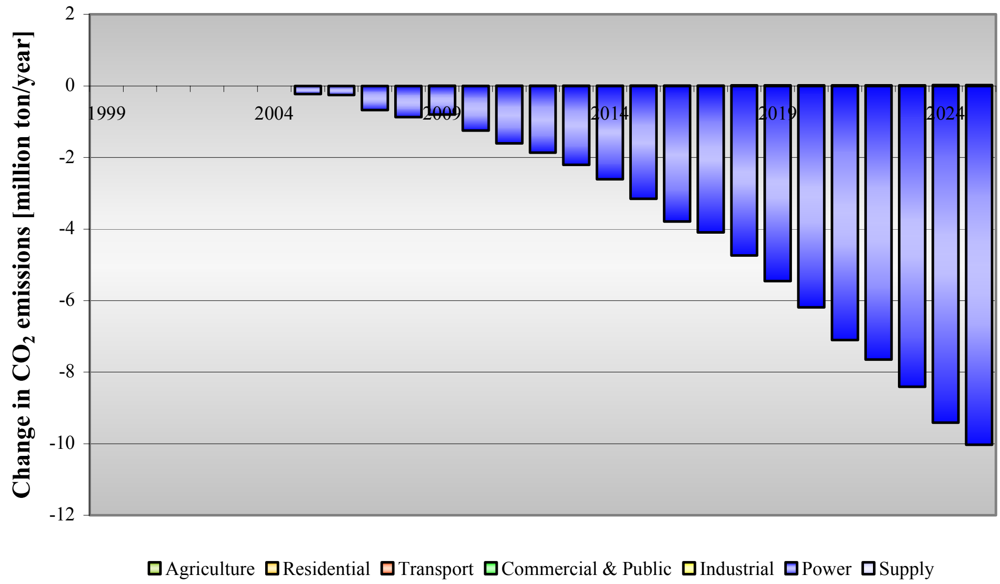

Figure 6.48 Change in CO_2 emissions by sector (Renewables case minus Reference case).

The combined effect of technologies, solar PV and wind, for example, on CO_2 emissions is shown in Figure 6.48. As can be seen, the accelerated penetration of renewable power generation results in CO_2 emissions that are up 10 million ton per year (2025) below the reference case levels. This represents a 5.4 percent decrease in power sector CO_2 emissions and a 1.2 percent decrease of total national CO_2 emissions. The total cumulative emissions reductions in the period from 2005 to 2025 are equal 81.96 million ton. The cost-effectiveness of solar and wind as a GHG mitigation technology is therefore US$5.6/ton CO_2. This value is likely to be lower if we ignore the more expensive solar technologies and include only wind in the model. This should be an area of future investigations.

6.8. Conclusions, recommendations and observations

The first type of conclusions refers to the attainment of the objectives of the project in its two phases. For Phase I, according to the DECADES methodology, the country specific data base (CSDB) for Mexico was created; the initial screening of the candidate technologies for the electric system expansion was done in terms of their technical performance, economic competitiveness and environmental impacts; comparative assessment of full energy chains was the most difficult task of the project due to the amount, detail and complexity of the data required; the comparative assessment of electricity system expansion strategies until 2025 was successfully completed, with one base case and 14 alternatives considered.

For Phase II of the project, according to the ENPEP methodology, the country specific database for Mexico was created reflecting the structure of the Mexican Energy System with the detail that the available information allows to carry out. The available information allows creating and incorporating to the model a Mexican energy system structure into 7 great sectors. A supply sector disaggregated in two sub-sectors (oil and gas sector and coal sector); a power sector split into 8 thermal generation technologies and two renewable energy sources; an industrial sector disaggregated into 17 sub-sectors, five of them expressed in terms of final energy services; a residential sector also disaggregated in terms of final energy services; a transport sector disaggregated into 5 transportation modes and two sectors (commercial and public sector and agricultural sector) incorporated in terms of final energy demand. The structure incorporates 19 primary and secondary energy sources for the set of sectors and sub-sectors as well as 8 energy sources as raw material in the industrial sector. Also, it incorporates 9 pollutants through their emission factors.

This structure allow to project the need for primary energy in Mexico for the period through 2025 that is driven by the expected demand growth for all energy sources; to identify domestic supply sufficiency for major energy resources, the long term need for energy imports, and the potential for energy exports; to study energy infrastructure development to support the growing energy use in Mexico; to analyze, in view of the projected high reliance of the power system and other demand sectors on natural gas, the development of the gas sector in detail in order to identify possible supply constraints, price implications and relevant policy measures; to identify the potential role of renewable energy sources in the Mexican energy system; to quantify environmental emissions of the whole energy sector associated with the expected growth of energy consumption and possible emission mitigation measures and to provide, by considering several alternative scenarios, a set of possible scenarios as input to national decision-making in the energy sector.

The second type of conclusions is related to the usefulness of the tools supplied by the IAEA to the Government of Mexico and their use in future studies. In relation with the first phase of the project although CFE had for some years been using the WASP module for electric system expansion analysis, the supply of the DECADES package with the additional VALORAGUA and the DAM models has increased qualitatively the capacity for analysis of the hydro-thermal interaction and of the environmental impacts of the electrical generation system. Also SENER and UNAM have benefited from the availability and detailed knowledge of these tools because they can be used skillfully in further studies.

For the phase II of the project the tool supplied by the IAEA to the Government of Mexico was the ENPEP model developed by Argonne National Laboratory. This IAEA tool in conjunction with the energy demand model MODEMA developed at the Dirección General de Servicios de Cómputo Académico of UNAM allow to study the energy supply and demand implications incorporating the effect of energy prices and the competition between different energy sources.

The third type of conclusions refers to the synthetic analysis of the main results of energy projections for the entire Mexican energy system as for the study of the system level expansion of the power sector and the DAM program. In this respect, the basic expansion of the interconnected system would be based on natural gas-fired combined cycle units, with some gas turbines for peak demand hours. Nonetheless, the possibility of natural gas prices increases makes it desirable to consider some diversification using alternative technologies such as coal fired dual units, fuel oil units, and nuclear units. In such cases the total discounted costs can increase but a higher diversification is provided, the dependence on foreign fuel sources supply is reduced increasing the independence of this strategic sector. Moreover, some environmental benefits can be obtained as well, such as lower CO_2, NO_X, PM and SO_2 emissions in the case of nuclear units and renewable energies.

The ENPEP methodology allows a detailed analysis of the effects of such an energy policy on the Mexican oil and gas industry as well as the effects on the energy supply and consumption of the rest of the economical activities. In addition allows studying and analyzing the environmental impacts of the energy supply and consumption activities.

The fourth type of conclusions to be derived from the study is the need for SENER, CFE and UNAM to analyze with much more detail the issue of economic, environmental, social and political impact of the diversification of the mix of technologies for the long term expansion of the electric system in Mexico as well as for the entire Mexican energy system. This conclusion arises from the vulnerability that exists in case of limitations in the supply of natural gas or in the increase of their prices.

In the context of diversification it can be recommended that SENER, CFE and UNAM study the possible economic and environmental benefits of incorporating more wind, solar and geothermal units as candidate technologies for the expansion of the electric system and alternative technologies in the other sectors of the Mexican energy system. The results of these studies could indicate the need to incorporate wind and solar technologies in the COPAR document of CFE as well as in the outlook of the electric sector published by SENER [5]. On the other hand, at the level of the integrated Mexican energy system the need for the study of the possible economic and environmental costs and benefits of incorporating new technologies for transportation, industrial process and final end uses in the different sector of the energy system.

For the four scenarios analyzed in the present study the specific and detailed conclusions, observations and recommendations are as follows:

6.8.1. Reference case

Under the selected GDP and population scenarios and unlimited natural gas case –reference case- the main conclusions, recommendations and observations are:

6.8.2. Energy

- Mexico will continue to rely heavily on fossil fuels for its energy trade and final energy consumption.

- Crude oil market share decrease from 68.2 percent in 1999 to 62.7 percent in 2025, as a consequence of the non-associated gas growth share in 11.9 percent in 2025 (compared with 4.5 percent in 1999) meanwhile associated gas decrease from 13.9 percent in 1999 to 12.8 percent in 2025. Non-associated gas average annual growth rate is the highest (5.2%) followed by coal (3.7%), crude oil (1.0%), geothermal (0.8%) and sugar cane bagasse (0.2%).
- Crude oil production increase, in millions of barrels per day, from 2.91 in 1999 to 3.49 in 2005, to 3.58 in 2010, to 3.65 in 2015, to 3.72 in 2020 and 3.78 in 2025. The projected production allow to satisfy the internal consumption (feedstock for the domestic refining system (1.35 million barrels per day in 1999 and 1.71 million barrels per day in 2025), including the programmed expansion of the refining capacity in the system, as well as the maquila mechanism along the entire period) plus the projected crude oil exports (1.55 million barrels per day in 1999 to 2.07 million barrels per day in 2025).
- In order to reduce the dependency on imported gasoline and increase gasoline exports refining capacity has to increase according to the following results: by 2006 domestic refining capacity increase to 1.715 million barrels per day, which will cover, in essence, the projected gasoline demand with a deficit of 27,000 barrels per day (this demand deficit could be covered through the maquila mechanism or through imports); after year 2008 and the rest of the projection period, once the completion of the reconfiguration program with a gasoline yielding of 39 percent, the total refining capacity increase, in millions of barrels per day, up to 1.94 by 2008, to 2.48 in 2015, 3.16 in 2020 and to 4.07 in 2025. Therefore, the accumulated increase capacity along the projection period is 2.36 million barrels per day. The elimination of the gasoline exports has the effect to reduce the additional capacity to 2.1 million barrels per day.
- Natural gas production and imports increase its participation in the total primary energy supply at an average annual growth rate of 4.8 percent along the entire period. Associated and non-associated gas production grow at an average annual growth rate of 1 and 5.18 percent, respectively, while natural gas imports grow at an average annual growth rate of 15.75 percent. To keep a proper balance between supply and consumption with an important participation of domestic production, starting 2010, it will be necessary to incorporate more non-associated gas fields to production. The market share of natural gas increases to 45.3 percent by 2025.
- In order to handle the natural gas production and the imports, natural gas infrastructure (production wells, gas pipelines, processing centers and distribution) will have to grow at an accelerated level.
- Natural gas will be the primary fuel of choice for power system expansion and generation leading to a near term and long term need for additional gas imports (or accelerated expansion of domestic production). Natural gas-fired generation share will increases from 8.09 to 78.94 percent.
- Fuel oil generation share decreases from 53.96 to 2.46 percent as a result of the fuel oil reduction policy in the country and the conversion of fuel oil based dual generation units to imported coal. Therefore, coal imports will increase from 3.36 million ton per year up to 7.99 million ton per year in 2002 and stay at the same level for the rest of the projection period.

- In absolute terms coal generation grows, however its share decreases from 9.82 to 6.61 percent.
- Diesel shows an increasing share from 0.66 to 2.02 percent as a result of its use in coal power generation plants and other sectors.
- Hydro and geothermal generation also grows in absolute terms, but their shares show a decreasing pattern.
- Nuclear generation decreases in absolute and percent wise terms due to no nuclear additions in the expansion scenario for the power sector and the retirement of the first unit of Laguna Verde nuclear power plant.
- Wind participates in the total generation with a very small amount and a decreasing share.
- Mexico will continue to rely heavily on refined oil products for its final energy consumption. Final energy consumption will increase at an average annual growth rate of 3.41 percent along the entire period.
- Mexico's transport sector will continue to grow rapidly, at a 4.89 percent average annual growth rate, making transportation the largest final energy consumer in the country. Its market share grows from 38.39 percent in 1999 to 50.15 percent in 2025. Gasoline is expected to grow at an average annual growth rate of 4.99 percent, diesel at a 4.73 percent, kerosene at a 4.43 percent and LPG at a 3.25 percent. Fuel oil is expected to decrease at an average annual growth rate of 0.8 percent while natural gas increases its participation in road transport at an average annual growth rate of 24.27 percent. For natural gas penetration in the transport sector, it remains to see how real is this penetration rate under constraints on the availability of natural gas, transportation and distribution infrastructure.
- Industrial sector is the second highest final energy consumer with a 3.68 percent average annual growth rate; however its market share drops from 38.73 to 37.43 percent.
- Main energy consumption will be placed in the Cement, Iron and Steel, Chemical, and PEMEX Petrochemical sub sectors accounting for 46 percent of the total consumption.
- Natural gas and electricity will continue to be the most used fuels in the industrial sectors accounting for 65 percent.
- No changes of significance in the structure of the industrial energy consumption, other than the drastic reduction on fuel oil consumption, are to be expected.
- Nonetheless it is to be notice the impact of natural gas availability and price volatility in the energy bill of the industrial sector and the rest of the sectors.
- It is also to be noted the evolution of co-generation and self-generation in the industrial sector which are expected to grow 108 percent along the projection period; however the availability and price volatility of natural gas can cause adverse effects in these power generation activities.
- In the sugar sector biomass-based cogeneration, employing modern, efficient technology can be a cost-effective and a low greenhouse gas-emitting option but need significant investments to be developed.

- Final energy consumption in the agricultural sector increases at an average annual growth rate of 2.5 percent, but its market share falls from 2.9 to 2.08 percent. Clearly, if the needed re-activation of the sector and the current negotiations with the farmers have success, the impact on the energy consumption of the sector could be important.
- Commercial and public sectors energy consumption increases at an average annual growth rate of 2.22 percent; however its market share drops from 2.96 to 1.98 percent. Electricity becomes the main energy source with an average annual growth rate of 5.1 percent. The commercial sector has a good potential for electricity generated through renewable energies, both biomass and solar. Also, solar energy for water heating in substitution of fossil fuels has a good potential in the sector.
- Residential sector final energy consumption grows at an average annual growth rate of 1.01 percent loosing market share from 17.02 to 8.36 percent. LPG continues as the most important fuel in the sector in competition with natural gas. Firewood continues as the second energy source followed by electricity.
- As a result of the natural gas and fuel oil policies national CO2 (346.1 and 828.41 million ton in 1999 and 2025, respectively), NOX (1.52 and 4.61 million ton in 1999 and 2025, respectively), and PM (323.2 and 484.26 thousand ton in 1999 and 2025, respectively) emissions will increase while SO2 (2.35 and 1.78 million ton in 1999 and 2025, respectively) emissions are projected to decline.

6.8.3. Emissions

- By all means, the transport sector (shares of 31.08 and 44.73 percent in 1999 and 2025, respectively) becomes the most important contributor to the CO2, emissions followed by the power (shares of 28.37 and 23.31 percent in 1999 and 2025, respectively, showing the benefits of the energy policies in the sector), industrial (shares of 16.85 and 17.8 percent in 1999 and 2025, respectively) and supply (shares of 15.06 and 8.71 percent in 1999 and 2025, respectively) sectors. Residential, agriculture and commercial and public sectors contribute with shares of 8.64 in 1999 and 5.45 in 2025. Nevertheless, residential and commercial sectors are good candidates for the introduction of renewable energies, both biomass and solar for electricity generation as well as solar energy for water heating in substitution of fossil fuels.
- Also, transport sector is the most important contributor to the NOX emissions (shares of 66.84 percent in 1999 and 73.62 percent in 2025) followed by the power sector (18.59 percent in 1999 and 18.17 percent in 2025). The rest of the sectors contribute to these emissions with the 14.57 percent in 1999 and 8.21 percent in 2025. Clearly, actions aimed to reduce NOX emissions must have as its primary target the transport and power sectors, nevertheless existing technologies, rational energy use and fuel substitution measures can contribute to reduce the emissions in the other sectors.
- For PM emissions, also, the transport sector is the most important contributor (shares of 18.42 percent in 1999 and 42.97 percent in 2025) followed by the industrial sector (24.66 percent in 1999 and 29.28 percent in 2025). As a result of the energy policy in the power sector PM emission decrease from a share of 28.45 percent in 1999 to 3.89 percent in 2025. The supply sector reduces it share from 26.7 percent in 1999 to 21.86 in 2025, however, in absolute terms shows an increase in the PM emissions. The rest of the sectors show an increase in its share (1.71 percent in 1999 and 1.99 percent in 2025).

Finally, SO_2 emissions show a decreasing pattern. The origin of this behavior is the energy policy in the power sector with shares of 72.9 percent in 1999 and 21.67 percent in 2025. However, part of this beneficial result in wiped out by the increase in the industrial sector (shares of 18.85 percent in 1999 and 60.19 in 2025), the increase in the supply sector (shares of 5.03 in 1999 and 8.62 in 2025), the increase in the transport sector (2.33 percent in 1999 and 7.38 in 2025). The rest of the sector also have increases and, as a set; represent participations of 0.9 percent in 1999 and 2.15 in 2025.

6.9. Alternative scenarios

6.9.1. Limited gas scenario

6.9.2. Energy

- If natural gas supply is limited, the power sector may shift to imported coal combustion for system expansion substantially decreasing the need for gas imports. However, this shift will come at an economic and environmental expense leading to significantly higher system costs and atmospheric emissions.
- Natural gas imports will keep, essentially, the same value as in the reference case, however, starting 2014 there will be a reduction in the natural gas imports of 5.87 percent with respect to the reference case and this difference will reach a 33.78 percent by 2025, also with respect to the reference case. Clearly, this will lower the pressure for the development of the needed infrastructure for production, transportation and distribution of natural gas; however, it will transfer this pressure to the development of the corresponding infrastructure for the reception, transportation and distribution of imported coal. According to the available information, current coal reception, transportation and distribution infrastructure allows for the handling of 4 million ton per year. Under this scenario this infrastructure will have to grow and be able to handle 9.5 million ton in 2014. After 2014, the coal-handling infrastructure will have to grow fast reaching a total handling capacity of 84.81 million ton of coal per year by 2025.
- Due to the natural gas supply limitation, the remaining sectors will adjust their energy mix, reducing the participation of natural gas and distributing the reduction between the remaining fuels in their energy mix. According to the model's methodology, is expected that these distributions occur under the price competition for the different fuels within a given sector and between sectors. Since the current energy policy puts strong emphasis on the power sector, the natural gas supply limitation affects, directly to this sector, while for the remaining sectors the effect is less important.

6.9.3. Emissions

- Not surprisingly, the shift from natural gas to imported coal comes at an environmental cost. Atmospheric emissions are projected to increase under the limited gas scenario. Compared to the reference case, power sector CO2 emissions are forecast to reach about 238.69 million ton by 2025, which is about 45.62 million ton over or 23.63 percent higher than the reference case in 2025. Emissions of NOX exhibit a similar behavior under the limited gas scenario, they reach about 989,590 ton by 2025, which is about 152,180 ton or 18.17 percent higher than he reference case in 2025. The PM and SO2 emissions from the power sector are forecast to increase by 15,770 ton and 113,910 ton by 2025, respectively, also with respect to the reference case. In essence, the remaining sectors show, relatively small changes in their contributions to the emissions with respect to the reference case.

6.10. Nuclear Scenario

6.10.1. Energy

- Nuclear power also replaces base-loaded gas-fired generation and thereby can lead to lower gas imports and lower emissions. Because of the large capacity of the nuclear unit, the expansion schedule is slightly affected starting in 2001 even though the unit is not coming on-line until 2012. This leads to some changes in generation and fuel consumption in the power sector between 2001 and 2011. Between 2001 and 2011 there is an additional participation of fuel oil generation, which decreases along the years and ends by 2011 and a reduction in the consumption of natural gas. When de nuclear unit does come on-line, it is base-loaded into the system and generates a constant level of 34 PJ of electricity per year equivalent to 1.5 percent of total generation in 2025 as compared to 1.1 percent under the reference case. The system-level analysis shows that nuclear replaces effectively base-loaded gas combined-cycle capacity and between 33-37 PJ of gas-fired generation. This represents a reduction in the imports of natural gas of 189.6 million cubic feet per day and an additional consumption of uranium dioxide of 31.31 ton per year. The remaining sectors show minor changes.

6.10.2. Emissions

- The changes in dispatch in the early years lead to small emissions increases of up to 1.2 million ton of CO_2 per year in 2003. But emissions are noticeable reduced starting 2012 when the nuclear unit eventually comes on-line. CO_2 emissions reductions vary between 3.6 and 4.0 million ton per year, equivalent to 1.9 percent reduction in power sector emissions and a 0.4 percent reduction in national emissions. Total cumulative reductions are 47.5 million ton of CO_2 and the cost-effectiveness of nuclear technology as a GHG mitigation technology is therefore US$5.8 per ton of CO_2.
- NOX emissions show a similar behavior and annual reductions vary between 15,000 and 17,000 ton of NOX. The cumulative emissions reductions total 228,000 ton.
- PM and SO_2 emissions exhibit a similar behavior as CO_2 and NOX emissions. Total cumulative emissions reductions of SO_2 and PM emissions for the entire period are 242,790 and 14,320 ton, respectively.
- This calls for specific studies on the nuclear option. Special attention has to be paid to the total cost of the expansion scenarios including the internalization of the environmental externalities of the whole energy chain and looking for the total cost at which the nuclear option becomes competitive.

6.11. Renewables scenario

6.11.1. Energy

- Because of the relative costs of wind and solar, the role of solar PV will be very limited. By 2025, solar will generate only about 1.2 PJ of electricity or 0.1 percent of total generation. This is equivalent to 195 MW of installed PV capacity.

- Wind, on the other side, is forecast to penetrate the market relatively rapidly. This energy source is forecasted that will account approximately 4.9 percent of total generation that is 78.3 PJ by 2025. At the assumed capacity factor of 26.2 percent, about 9,500 MW of wind capacity will be needed to generate this power.
- Wind will essentially replace marginal gas-fired generation by up to 93.3 PJ in 2025, that is, about 19 percent more than wind electricity. The main reason for this difference is the underlying model implementation which assumes that wind generation will be more dispersed, closer to actual loads, and therefore not subject to the transmission and distribution losses of the electric grid.
- Due to the change in generation originated by the incorporation of wind energy, the power sector will require less natural gas and as a consequence less natural gas imports. The reduction in natural gas imports grows as wind generation increases and reaches approximately 178.31 PJ by 2025, which is equivalent to a reduction in the natural gas imports of 508.63 million cubic feet per day with respect to the reference case.

6.11.2. Emissions

- Renewables can contribute to GHG mitigation but their potential is somewhat limited as they mostly replace gas-fired generation.
- The combined effect of the accelerated penetration of renewable technologies in the power sector, solar PV and wind, results in CO2 emissions that are up to 10 million ton per year in 2025 below the reference case levels. This represents 5.4 percent decrease in the power sector CO2 emissions and a 1.2 percent decrease of total national CO2 emissions. The total cumulative emissions reductions in the period 2005 to 2025 are equal to 81.96 million ton.
- The cost-effectiveness of solar and wind a GHG mitigation technologies is therefore US$5.6 per ton of CO2. This value is likely to be lower if we ignore the more expensive solar technologies and include only wind in the model.
- This should be an area of future investigations in the power sector and other sectors as is the case of solar energy for water heating in substitution of fossil fuels in the residential and commercial sectors [4] as well as in the industrial sector.
- Also, it will be necessary to get and produce better information on the renewable energy costs and prices.

6.12. Additional comments and recommendations

It is known that in terms of the pure economic analysis *e.g.* considering the total cost of the expansion scenarios, the optimal solution is the Base Case or the decreased reliability scenarios, which is even more economic. But these decisions have the hidden costs of the environmental externalities (CO_2, SO_X, or other emissions), plus a possible security or diversification externality, which we have tried to understand and study. It is important to show the limitations of these scenarios in terms of environmental and social costs.

If the environmental externalities of the emissions are internalized, not only for the power plant but for the whole energy chain considered and the entire energy system, then the cleaner expansions (considering the forced nuclear expansion or increasing the reliability of the system), become potentially optimal and at the higher range cost of the CO_2, the forced nuclear expansion solution becomes optimal. This is not a surprising result since the nuclear unit is a zero emitter of greenhouse gases and if its operation starts in 2012, then a considerable amount of pollution is avoided. Using renewable resources such as wind power, which may have even better capital cost and construction periods, can produce the same effect. A study is under way to assess the introduction of such renewable resources, but was not included in this report.

On the other hand, if diversity is considered as an additional important component parameter, the options with higher diversity index become more competitive, and again some other options become optimal, for example the forced nuclear expansion and the limited combined cycle (LCC) scenarios are potentially optimal, being this last scenario optimal at the higher values of the diversity index. In both analysis the forced nuclear scenario (and equivalent forced renewable scenario), appear as good candidates for a reduction in environmental emissions and increasing the diversity of the system. Probably an optimal solution from the point of view of both emissions and diversity could be the introduction of a forced renewable scenario in the short term, and then a forced nuclear scenario in the longer term. This consideration remains as a matter of further study by SENER, CFE and UNAM.

As shown by the model results energy and energy services play and will continue to play a central role in the development of the Mexican energy system. The model results show how its needs for energy per unit GDP will increase steeply and how this growing demand for energy and energy services will have important consequences in emissions.

In general terms the model results reflects the mitigation strategy for greenhouse gases and other pollutants adopted recently by the Mexican government aiming to reduce fuel oil and LPG consumption and replace it by natural gas.

In light of the rapid growth of energy consumption in the industrial sector and other sectors, policies promoting energy efficiency and conservation should therefore continue to be an important component of energy policy. This energy policy and environmental management should shift towards a greater focus on structuring energy systems that promote sustainable development. Therefore, one of the key challenges for the Mexican energy system, today and in the future, will be the scaling up the activities of the different sectors in an economically, socially and environmentally sustainable way.

Energy efficiency measures include improved housekeeping procedures, maintenance, process control and automation, the replacement of outdated plant and equipment with the modern energy-efficient equivalent, and the recovery of embodied energy in recycled post-consumer wastes. This policy initiatives will have to be promoted in order to encourage the transfer and deployment of energy efficient technologies and/or measures which would then enable the system to deliver energy efficient products and services to consumers.

There is also a need to increase energy data availability and quality in the all the sectors. This is strictly necessary in order to improve the results of the model and the benefits of its use. Significant efforts are to be done in the characterization of the different conversion processes used in the industrial and other sectors. It is urgent to improve availability and reliability of the information related to energy efficiency, costs, final end uses, input/output ratios for different processes and final end uses, etc. This could be achieved by providing information, sources of information, accessibility to the information and a compromise of confidential and correct use of the provided information.

7. SPECIAL CHAPTER: "COMPARATIVE ASSESSMENT OF ENERGY SOURCES FOR ELECTRICITY SUPPLY UNTIL 2025"

7.1. Objectives and methodology of the study

This special chapter concentrates only in the discussion and results of the first phase of the national TC-project MEX/0/012: "Comparative Assessment of Energy Sources for Electricity Supply until 2025" that was carried out in the period 1999-2000. A study was conducted by the Mexican expert's team under the coordination of SENER using DECADES tool that was provided by IAEA. Under this project, a comprehensive assessment of different energy supply options was conducted with environmental considerations in order to identify sustainable strategies to support the expected growth in electricity demand in Mexico. These results would provide in turn, the Mexican authorities with comprehensive information to make sound decisions regarding the expansion of the national electricity system.

7.1.1. Overview of the Mexican electric system

At present, the Mexican Public Power System produces electricity through the combustion of fossil fuels (coal, fuel oil, diesel and natural gas), through nuclear fuels, hydro resources and renewable energies (geothermal and wind). In 1999 the total primary energy consumption accounted for 6,280.49 PJ, of which Power Sector consumed 1,858.98 PJ producing 651.30 PJ of electricity (equivalent to an amount of brut power generation of 180.92 TW·h). Mexican power system rests, strongly, on fossil fuels and, as a consequence it becomes an important contributor to the global emissions of the country. In 1999 total capacity of the public power system was 35,666 MW, its composition by type of technology was discussed in Chapter 2, Section 2.4.2. Also, during 1999 total generation of the public power system was 180.92 TW·h. It is estimated that private producers contributed with an amount of 11,317 GW·h during 1999.

Country's actual energy policy privileges power generation through natural gas in detriment of fuel oil and nuclear. In this aspect, two independent prospective studies [3][4] indicate an important increase in the contribution to the power generation from natural gas and, also important, a reduction in fuel oil contribution. Natural gas increase is projected, mainly, through combined cycle generation technologies. Fuel oil reductions include the conversion to natural gas of eight fuel oil power plants (4,051 MW) and a dual power plant to imported coal (presently, Petacalco's power plant consumes fuel oil); all of them located in environmentally critical areas (Appendix I). Therefore, their conversion obeys to environmental and, in some cases, to economical reasons. However, due to the recent escalation of natural gas prices it becomes necessary to review this electric expansion policy, as well as the natural gas policy, and reevaluate the contribution of fuel oil, nuclear and other options.

Environmental impacts related to the operation of Electrical Energy Systems comprise the direct or indirect adverse effects and disadvantages phenomena that must be taken into consideration when discussing such a type of systems. Impacts are connected with the production, transmission, distribution and utilization of electrical energy, in both normal operation and other situations. In this sense, the environmental impacts related to the Electrical Energy Systems result from numerous complex phenomena and interactions, starting with the activities related to the exploration, mining, transportation, transformation of the fuels used in power generation up to the its utilization of the electricity for producing energy services.

Because of the complexity, generally is not possible to deal with all of the potential burdens, pathways and types of impacts in a single environmental impact study. The approach usually taken is to focus the environmental impact study on identifying and analyzing those, which appear, on a first review, to have the largest potential impacts in the specific situation. Owing to this, however, it is possible that some eventually important impacts will be overlooked. Also, this approach means that the potential environmental impacts of the different candidate energy sources and generation technologies are not fully evaluated. Therefore, resulting comparative assessment will not incorporate all aspects for the different options, which could lead to a "less than best" expansion strategy. In such a case, it will be necessary to review and monitor the performance of the strategy in order to determine whether any unforeseen damages are occurring, and to mitigate such effects.

The importance of energy sector planning and decision-making and, in particular, planning and decision making in the electrical sector has increased in the recent years due to its economical, social and environmental impacts. These two central activities, planning and decision making, must take into account a range of factors related to the entire fuel chain of the energy source, including their technical and economic performance as well as their impact on health and environment.

Cost, environment, options and strategies must be analyzed and compared in many different ways. Therefore, it is necessary to develop and apply tools, techniques and data for comparative assessment of different electricity generation options and strategies. In this sense, DECADES provides an enhancement, to some extent, of capabilities for comparative assessment of different electricity supply options and strategies in the process of planning and decision-making in the electricity sector.

The electricity planning perspective requires general characteristics data and analysis tools in order to understand the options available, as a function of the differences and tradeoffs between economic, health and environmental aspects of the different electric power technologies and alternative electricity supply policies. Therefore, this requires a detailed understanding of entire electric power system, the capacity growth that has to meet in the future, data on the fuel options and plant candidates for meeting the capacity expansion requirements, methods for the calculation of health impacts and environment related emissions and burdens from the cost-optimized expansion strategies. Also, the analysis is by nature highly specific and requires detailed data on the project costs, emissions and other burdens resulting from the plant construction and operation.

7.1.2. Objectives

The main study objectives are:

- To develop a Country Specific Data Base (CSDB) including technical, economic, and environmental parameters of alternative electricity generation technologies and their full energy chains; and,
- To study alternatives for the expansion of the Mexican generating system until 2025 at four analytical levels:
- Plant-level analysis;
- Chain-level analysis;
- System-level analysis; and,
- Decision-making analysis.

7.1.3. Methodology

The following methodological steps have been implemented in the study:

- Identify all possible fuels in the country (imported fuel included) in order to create the fuel inventory and implement them in CSDB. For each fuel (gas, oil, coal and nuclear) the potential resource and its availability for future plans are considered. The database involves the source, type and subtype of fuel and it contains economic, technical characteristics and environmental factors.
- Establish the existing electricity generation technologies (thermal and hydro plants) and consider candidate technologies. Some technologies to be considered are combined cycle based on natural gas; dual power plants based on coal with desulphurization, gas turbine, and nuclear power plants (ABWR) and a list of hydro power plants as candidates.
- Establish the auxiliary inputs for every step in the chain, e.g. self-consumption in its process (electricity, fuel, heat and mechanical power).
- Link the determined technologies for existing and candidates plants with the fuels to be considered according to the regional availability.
- In order to select the power generation plants considered as expansion alternatives, the screening curves for each technology will be prepared with the objective to determine which of these plants are more attractive.
- Define the chain boundaries (within the country boundaries) by energy chain (e.g. gaseous fuel, liquid fuel, solid fuel, nuclear, hydro and geothermal) and by steps in the energy chain (*e.g.* mining, transportation, preparation, electricity generation).
- Establish allocation criteria for steps in the energy chain with multiple inputs/outputs such as refineries and drilling sites. Review the direct and indirect emission factors for main air pollutants. Assess the emissions of radionuclides in air and water from the nuclear energy chain. Estimate chain specific emissions (e.g. CH4 emissions associated with the hydro reservoirs). Calculate levelized full chain electricity generation costs. The calculation performed will take into consideration different chain specific aspects, such as transportation distance for fuels.
- Assess and compare the full energy chains of the country (gaseous fuel, liquid fuel, solid fuel, nuclear, hydro and geothermal) in terms of their technical performances, economic characteristics and environmental parameters and considering their steps: mining, transportation, preparation, electricity generation, and waste disposal. Compare the levelized full chain electricity generation costs and air pollutants and air emissions of radionuclides.
- Perform analysis considering all possible supply sources in the country and select the expansion scenarios to be studied in order to obtain different alternative expansion plans which take in consideration technical, economic and system reliability factors. These alternative expansion plans will be assumed in order to provide information to the decision makers and obtain a robust plan.
- Define different scenarios in order to be able of study the impact of higher demand growth, nuclear option, escalation of fossil fuel prices, limitations of new gas-fires units, discount rate and changes of the reliability on the power system expansion.

- Prepare information about fixed system and candidate technologies aggregating in the database technical and economic data.
- Prepare additional information, which is necessary to perform the system analysis (demand, economic parameters, operation constrains and reliability criteria).
- Carry out the system analysis using DECPAC; the analytical software of DECADES, in order to obtain the optimal solution of different expansion alternative plans incorporating Valor Agua model results interactively.
- Select a number of alternatives over which we can take a decision about. Define criteria, such as CO2, SOx, NOx, particulates emissions and the criterion for the diversity of the system as represented by the Stirling Index, and determine weights to study/evaluate the scenarios selected.
- Conduct decision-making analysis of the selected alternatives using the DAM (Decision Analysis Module) of the DECADES package with all gathered data in order to obtain the relevant conclusions to be given to the decision makers.

7.1.4. Modeling approach

As described earlier, DECADES is the modeling tool that was used in this part of the study. It is an integrated software package developed to provide senior analysts and energy experts with an easy to use tool for carrying out decision support studies for the power sector. Briefly, these tools consist of:

- Several databases providing a comprehensive, harmonized set of technical, economic and environmental data for energy chains that use fossil fuel, nuclear power and renewable energy sources for electricity generation;
- A data management system which provides user friendly access to the DECADES databases;
- An analytical software designed to access the information stored in the databases for analysis of costs and environmental burdens at the power plant, full energy chain and electric system levels; and,
- A decision analysis tool.

The DECADES tools are RTDB, CSDB, HEIES, and DECPAC. They consist of databases and analytical programs, which can be used for national, regional and international studies in order to evaluate trade-offs between technical, economic and environmental aspects of different electricity generation technologies, chains, and systems. For a detailed description of the DECADES methodology see section 3.3 of the Summary of the present report.

7.2. Chain-level analysis

As was mentioned in Section 7.1.2, the study of the alternatives for the expansion of the Mexican generating system was carried out at four analytical levels: plant-level analysis, chain-level analysis, system-level analysis and decision-making analysis. Plant-level analysis provides to the user with a preliminary screening of different electricity generation options, emission factors for main air pollutants are estimated based on fuel characteristics and power plant performances. On the other hand, System-level analysis also provides a screening of the generation system expansion strategies and the conduction of comprehensive studies to develop mixes of energy chains, which meet electricity demand for a country or region. The environmental residuals are estimated taking into account the full energy chains composing the system and the cost effectiveness of different air pollutant abatement strategies is also estimated. These two aspects are discussed in detail in Chapter 4 (Plant-Level and System-Level Analysis of Expansion Alternatives). In essence, Chapter 4 corresponds to the WASP analysis of the electric system. Therefore, the present chapter concentrates, also in detail, on the remaining two analytical levels, *i.e.,* Chain-level and Decision-making analysis.

Energy chain analysis comprises the analysis of different types of energy sources from exploration, exploitation, transportation, transformation, transportation and final use in the power plant. This chapter concentrates and highlights detailed impacts associated with the full energy chain for the principal energy sources and generation technologies with consideration of environmental aspects in the Mexican electrical system. Energy chains that are to be analyzed are fossil fuel (oil, diesel, natural gas and coal), nuclear, hydro, geothermal and wind energy.

A large number of energy chains (fossil, nuclear, hydro, other renewable energies) and technology options exist, each producing a range of waste streams and emissions. Some of the wastes may be of a nature, or at levels low enough, that they cannot be considered as harmful, and therefore are discharged directly to air or surface water bodies. Other wastes arise as solids that cannot be discharged directly. Others may contain hazardous substances at concentrations high enough to require some treatment for their safe management and special systems for their safe disposal. This treatment may result in further discharges to air or surface water bodies and the production of other wastes.

Figure 7.1 shows a graphical representation of a general fuel chain in DECADES tool. This general fuel chain has to be particularized for each of the fuel sources employed in the Mexican electrical system. This means that for a given fuel one has to go from the resource location up to the final use at the power station, passing through the mining or extraction, transportation to the processing plant, from there through transportation into the power plant, transportation of the waste and by products from the power plant to the treatment of waste facilities and, finally transportation of waste into the final disposition facility.

Chain-level analysis requires detailed and general data and allows presenting a broad view of the major tradeoffs between technical, economic, health and environmental aspects of the energy chains. Also allows a comparative assessment of the full energy chains for electricity generation, from resource extraction to waste disposal. Therefore, chain level results include: mass flow of fuels and waste, levelized cost of electricity generation and quantities of environmental burdens such as air pollution and total greenhouse gas emissions (CO_2 equivalent), water effluents, solid waste generation and land use. Environmental burdens from auxiliary inputs such as electricity, fuels and materials are also calculated. This auxiliary inputs will also contribute to the emissions and, therefore, they have to be added to the total estimation in order to provide an as complete as possible representation of the total environmental fluxes. The emissions originated from the auxiliary inputs are called indirect. As an example of auxiliary inputs and indirect emissions, let us consider the full coal chain and pay attention to the mining step. In this step one important factor to be considered in the mining of the coal is the electricity and fuel consumption. In this case the auxiliary inputs can be defined as the electricity, heat and mechanical energy required during this activity and they are considered as a separate type of energy. Therefore, not only direct (concentrated) emissions from the plants have to be covered but also indirect emissions have to be considered.

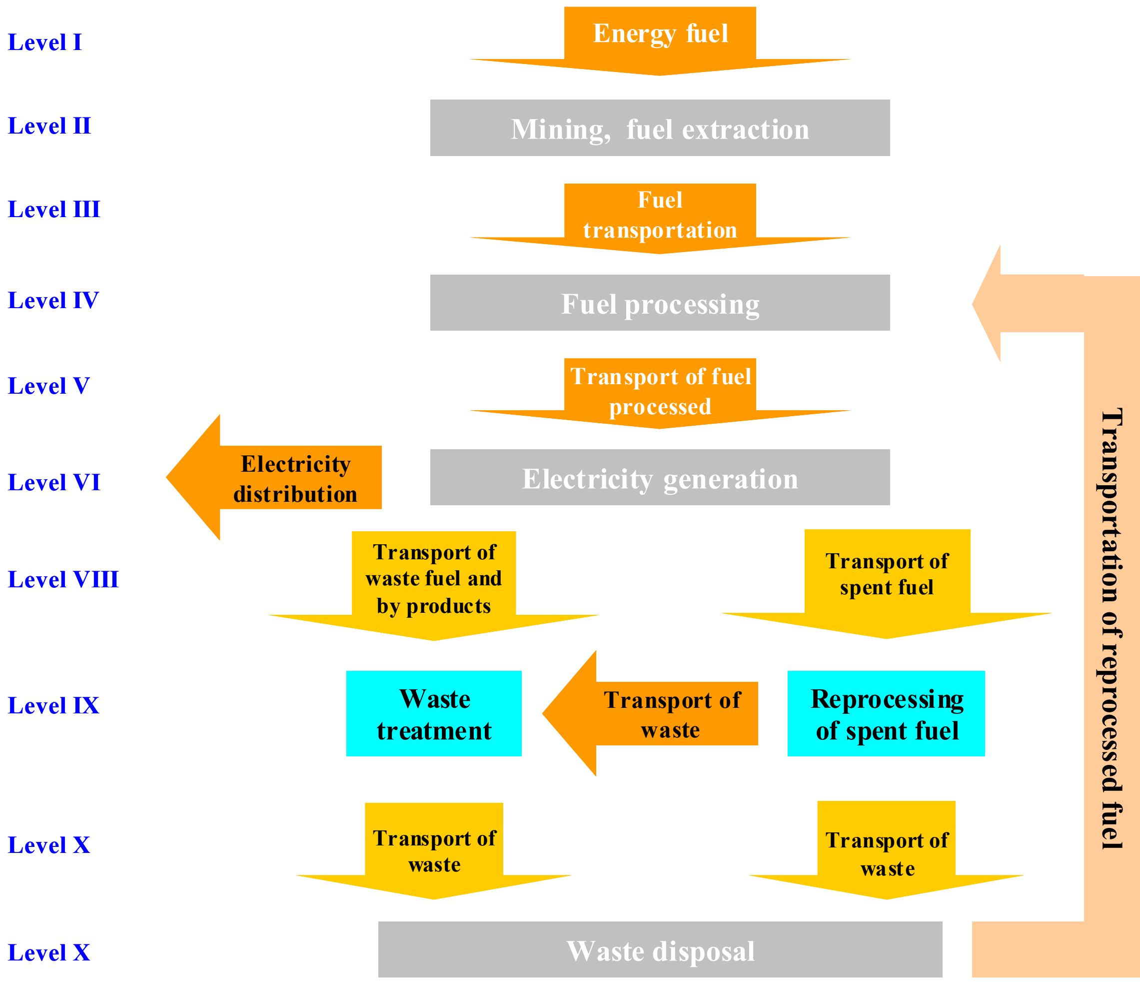

Figure 7.1 Graphical representation of a generalized fuel chain.

7.2.1. Oil chain

Fuel oil and diesel are derived products from the crude oil. In the case of Mexico oil resources are located onshore and offshore. At present most of the oil production comes from the marine oil fields, located in the Gulf of Mexico. Most of the present production of oil it is associated with natural gas. Fuel oil and diesel, two by-products of the petroleum industry, are used as boiler fuels in thermal plants for electricity production, but they have other energy applications also. Therefore, it is necessary to consider the full energy chain. The impacts from the oil chain for electricity generation are associated with the overall activities for the oil exploration, production, processing and transportation.

The specific chain we use for this case is shown in detail in Figure 7.2. Additionally, the figure shows the associated auxiliary levels for each of the primary level or steps. The discussion will be carried out step-by-step indicating the data and main assumptions we made in the preparation of the input for the chains. Each one of the auxiliary levels in the figure is connected with one and only one step. The auxiliaries can be diesel, electricity, mechanical energy, etc

For a general discussion of the crude oil and gas production, processing, transportation and their environmental impacts see Appendix IV of the present report. For the oil and gas chains, we will refer the discussion to the levels or steps shown in Figure 6.2 and our analysis will be carried out step-by-step along the specific chain.

7.2.2. Crude oil production (Level II)

Mexican crude oil is extracted from onshore and offshore oil fields. Offshore crude oil production accounts for the main portion of the total oil production. As we mentioned most of the oil production has natural gas associated with it. Once crude oil and natural gas has been separated, at the separation batteries, crude oil is sent, through pipelines, to the storage and distribution facilities for shipment into the crude oil processing centres (refineries) and to the preparation facilities for export to other countries.

In order to satisfy the domestic demand and maintain the exports platform PEMEX-Exploration and Production has reached a level of production of 3 million barrel of crude oil per day (Chapter 3, Table 3.11) and operates 324 producing fields with a total of 4 522 producing wells and 156 offshore platforms. Additionally, it operates 8 904 km of pipelines to collect the crude oil from the producing wells and transportation into the exporting facilities and refineries.

In the case of Mexico, most of the crude oil production is associated with natural gas, therefore, in order to prepare the data for the first step (level II in Figure 6.2) the initial assumption was to consider the whole crude oil production as associated with natural gas. This assumption implies the necessity to get information on several factors such as those shown in Table 7.1. Unfortunately, specific data for these factors was not available at the time of the present study, however, there was a very comprehensive study carried out by the Swiss Federal Institute of Technology Zurich (PSEL-LCA-1996) that provide us, in principle, with information very close to the Mexican case. Therefore, this study will be used extensively along the present study.

In addition one has to consider the energy requirements during crude oil extraction. These are related with the required electricity, fossil fuels, mechanical energy and heat for the operation of pumps, gas re-injection, and process heat for heater/treaters and CO_2 injection. Clearly, these energy requirements are responsible for the indirect emissions. Therefore, during crude oil production, it was assumed that diesel generators provide power for pumps and associated gas re-injections; heat for heater/treaters is provided by industrial fuel oil firing, and CO_2 injection (if is carried out) by gas-fired gas turbines.

Table 7.1 shows the values for these activities. Once we have the energy requirements, it is necessary to have the emission factors per each type of activity, fuel and equipment that are used during the different operations in the production stage. Tables 7.2 and 7.3 show these values for the direct and indirect emissions, respectively. The emission factors for the indirect are related to the use of diesel, fuel oil and natural gas in the production step.

Table 7.1 Factors related to activities during crude oil production

	Factor	**Unit**
Associated gas vented and flared	27.20[a]	cbm/ton crude
Associated gas flared in pipe flares (94.2% efficient)	12.24[b]	cbm/ton crude
Associated gas flared in ringed pipe flares and steam/air inject flares (98.3% efficient)	10.20[c]	cbm/ton crude
Associated gas flared in multi-jet flares (99.3% efficient)	3.81[d]	cbm/ton crude

Associated gas vented	0.95[e]	cbm/ton crude
Methane emissions from leaks, accidents, etc.	3.50[f]	kg CH_4/ton crude
Density of natural gas/methane	0.67606	kg/ton crude
Energy requirements (indirect)		
Diesel[g]	3.51×10^{-4}	TJ/ton crude
Fuel oil[g]	2.40×10^{-4}	TJ/ton crude
Natural gas[g]	6.40×10^{-5}	TJ/ton crude
Total[g]	6.55×10^{-4}	TJ/ton crude
Energy transformation factors		
Diesel heat content	45.4	MJ/kg_{diesel}
Fuel oil heat content	41.0	$MJ/kg_{fuel\ oil}$
Natural gas: heat content	0.04826	$MJ/kg_{natural\ gas}$
Diesel density	1186.0	l_{diesel}/ton_{diesel}
Fuel oil density	1058.9	$l_{fuel\ oil}/ton_{fuel\ oil}$

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirtschaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

[a] PSEL-LCA Study, Chapter 4, Table IV.7.34, page 78, establishes this value for the Latin American region.

[b] PSEL-LCA Study, Chapter 4, Table IV.7.34, page 78, establishes 45% of 27.20 for the Latin American region and Table IV.13.10, page 250 the value for the pipe flares efficiency.

[c] PSEL-LCA Study, Chapter 4, Table IV.7.34, page 78, establishes 37.5% of 27.20 for the Latin American region and Table IV.13.10, page 250 the value for the ringed pipe flares efficiency.

[d] PSEL-LCA Study, Chapter 4, Table IV.7.34, page 78, establishes 14% of 27.20 for the Latin American region and Table IV.13.10, page 250 the value for the multi-jet flares efficiency.

[e] PSEL-LCA Study, Chapter 4, Table IV.7.34, page 78, establishes 3.5% of 27.20 for the Latin American region.

[f] PSEL-LCA Study, Chapter 4, Table IV.7.35, page 80, establishes this value for the Latin American region.

[g] PSEL-LCA Study, Chapter 4, Table IV.7.24, page 74, establishes these values for the Latin American region.

Source: USEPA, GHG Inventory, Appendix Q, page 2.

7.2.3. Crude oil transportation (Level III)

Crude oil is distributed according to the share shown in Chapter 3, Table 3.11. Over 50% (53.7% in 1999) of the total domestic production is exported into more than 20 countries; the remaining amount is transported by pipeline into the 6 refining facilities and to La Cangrejera petrochemical facility, where after the extraction of naphthas and some light hydrocarbons for the production of aromatics, is sent back, by pipeline, into the refining facilities.

The second main assumption was to take into account just the pipelines from the marine regions, their length up to the coastal terminal of Dos Bocas and from Dos Bocas to the distribution centre of Nuevo Teapa and finally to each one of the processing centres. The offshore pipeline length to Dos Bocas terminal was estimated in 163.2 km; form Dos Bocas terminal to Nuevo Teapa distribution centre was estimated in 144 km. To these distances we have to add the pipeline length up to each one of the processing facilities. These facilities are located at the southeast, central and northeast parts of the country. With pipeline transportation, oil spills and fires can occur, with the most important initiating cause being damage to the pipeline. Table 7.3 shows the estimated pipeline lengths from the oil fields to each one of the 6 refining facilities. It is important to recognize that part of these distances is offshore pipelines and part is onshore. This was taken into account in the data preparation.

Table 7.2 Emission factors from venting and flaring, leaks and accidents (Direct)

Pollutant	**Flaring**[a]	**Venting**[a]	**Leaks and accidents**	**Combined factor**
	kg/cbm of gas flared	**kg/cbm of gas vented**	**kg/ton of crude oil**	**g/ton crude oil**
NO_X	1.2×10^{-2}			$3.04 \times 10^{+2}$
NMTOC/NMVOC		2.71×10^{-1}	6.6[b]	$7.10 \times 10^{+3}$
CH_4		$5.85 \times 10^{+1}$	1.97[c]	$3.06 \times 10^{+3}$
CO_2	$2.41 \times 10^{+0}$	1.4×10^{-2}		$6.11 \times 10^{+4}$
He	1.0×10^{-3}	1.0×10^{-3}		$2.72 \times 10^{+1}$
Hg	1.5×10^{-8}	1.5×10^{-8}		4.08×10^{-4}
222Rn (kBq/cbm)	1.0×10^{-1}	1.0×10^{-1}		$2.72 \times 10^{+3}$

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirtschaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

[a] PSEL-LCA Study, Chapter IV, Table IV.13.12, page 251.

[b] PSEL-LCA Study, Chapter IV, Table IV.7.35, page 80. The values are: low-pressure venting 4.8, accidents 0.1 and facility leaks 1.7.

[c] PSEL-LCA Study, Chapter IV, Table IV.7.35, page 80. The values are: low-pressure venting 0.43, accidents 0.04 and facility leaks 1.5.

For step III, we need data on the crude oil losses, the electricity requirements and diesel requirements for the offshore pipeline part. Again, the PSEL-LCA, 1996, provides us with the required information. Two contributions have to be considered in this step since we have direct and indirect contributions to the emission. Direct contributions are the result of the NMTOC/NMVOC, methane and VOC/TOC total (NMTOC + methane). Indirect contributions are originated in the electricity that is used and the diesel consumed by the diesel engines in the offshore facilities. These factors are shown in Table 6.4.

Table 7.3 Pipeline lengths for crude oil transportation

Processing facility	Offshore length km	Onshore length km
Cadereyta, Nuevo León	163.2	1 318.5
Madero, Tamaulipas	163.2	848.5
Minatitlán, Veracruz	163.2	172.9
Salamanca, Guanajuato	163.2	1 039.5
Salina Crux, Oaxaca	163.2	409.4
Tula, Hidalgo	163.2	629.1

Source: Data estimated on the basis of PEMEX data.

7.2.4. Crude oil processing (Level IV)

The Mexican refining system accounts for 6 refineries, Salamanca and Tula located at the central area of the country, Cadereyta and Madero in the northeast, Minatitlán in the south part of the Gulf of Mexico and Salina Cruz in the south pacific part of the country. Atmospheric distillation capacity accounts for 1.53 million barrels of crude oil per day and accounts for the highest capacity followed by vacuum distillation, reforming, catalytic and thermal cracking, hydrodesulfurization, visbreaking and natural gas liquids fractionation. A comparison with the bold-line boxes of Figure D.1 in Appendix IV shows that all of these processes have direct emissions to the air.

The composition of crude oil feedstock and the chosen slate of petroleum products largely determine a refinery's processing flow scheme. On the other hand, DECADES methodology requires the specification of the physical and chemical properties and composition of the fuel used in a specific power facility therefore will require establishing the particular crude oil processing facility form, which the fuel oil is coming from. In addition, for step IV the methodology only allows to define electricity requirements and not fuel requirements, therefore we have to combine everything into direct emission factors. Table 6.5 and 6.6 show the energy parameters and emission factors for chains using fuel oil.

Table 7.4 Energy requirements, crude oil losses and emission factors for step III

Crude oil losses	2.3[a]	$g/ton_{crude\ oil}$
Energy requirements		
Electricity requirements	20.0[b]	$Wh/ton_{crude\ oil}$ - km
Diesel requirements[c]	4.40×10^{-7}	$TJ/ton_{crude\ oil}$ - km
Diesel heat content	45.50	MJ/kg
Diesel density	0.85	kg/liter

Emission factors	**Emission factor direct $g/ton_{crude\ oil}$**	**Emission factor direct $g/ton_{crude\ oil}$ - km**	**Auxiliary electricity[e] onshore pipeline g/kWh**	**Large diesel[f] engines g/GJ**	**Auxiliary diesel offshore pipeline g/liter**
Particulates (total)			$1.202 \times 10^{+1}$	$3.000 \times 10^{+1}$	$1.158 \times 10^{+0}$
Particulates (PM-10)			$2.917 \times 10^{+0}$	$2.470 \times 10^{+1}$	9.532×10^{-1}
SO_X (as SO_2)			$1.174 \times 10^{+1}$	$4.340 \times 10^{+2}$	$1.675 \times 10^{+1}$
NO_X			$1.534 \times 10^{+0}$	$1.322 \times 10^{+3}$	$5.102 \times 10^{+1}$
CO			1.504×10^{-1}	$3.490 \times 10^{+2}$	$1.347 \times 10^{+1}$
HCl			4.902×10^{-2}		
HF			6.027×10^{-3}		
NMTOC/NMVOC	16.38[d]	1.081×10^{-2}	1.479×10^{-2}	$3.490 \times 10^{+1}$	$1.347 \times 10^{+0}$
CH_4	1.62[d]	1.069×10^{-3}	1.528×10^{-2}	$3.102 \times 10^{+0}$	1.197×10^{-1}
VOC/TOC total (NMTOC + CH_4)	18.00[d]	1.188×10^{-2}	3.007×10^{-2}	$3.800 \times 10^{+1}$	$1.466 \times 10^{+0}$
CO_2			$5.877 \times 10^{+2}$	$7.094 \times 10^{+4}$	$2.738 \times 10^{+3}$
N_2O			4.313×10^{-3}	n. d.	

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirtschaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

[a] PSEL-LCA Study, Chapter IV.8.8.6, page 110. The values are: 2.3 g/ton for all regions except in the CIS where the value is 154 g/ton.

[b] PSEL-LCA Study, Chapter IV.8.8.3, Table IV.8.22, page 108. The range for onshore pipelines is 17-33 Wh/ton - km. The Swiss Study used a value of 20. In the same page are reported values for offshore pipelines.

[c] PSEL-LCA Study, Chapter IV, Table IV.8.24, page 109.

[d] PSEL-LCA Study, Chapter IV, Table IV.8.19, page 105. General VOC emissions from crude oil transport is 18 g/ton with a 9% methane content (range of 0.5 - 25), we use 9% methane content.

Source: USEPA, Air Pollution Emission Factors, Vol. I, Stationary Point and Area Sources, AP-42, 5th edition, November 1996.

[e] These emission factors were estimated by a weighting procedure of the USEPA emission factors for electricity generation per type of technology and fuel. The weighting factor is the conversion factor per fuel and generation technology over the total

[f] USEPA AP42 provides values for the emission factor for Uncontrolled Large Diesel Engines under the Large Stationary Engines, EDE-2.

7.2.5. Fuel oil chain (Level IV)

As we can see, from Tables 7.5 and 7.6, many of the energy parameters are coming from the European situation. The assumption was that several national oil products are similar to the European ones, and that the introduction of them will provide us with the indication on which parameters we have to make an additional effort in order to obtain more representative values for the parameters (if is possible by refinery) of the Mexican refining system. On the other hand, the present *status* allow us to have a more complete data base for the different energy chains and show the strengths and weaknesses of the DECADES methodology and tools. All the values shown in Table 7.6 are the same for each of the refineries, the exception to this assumption were the values for the SO_X (as SO_2), in which we took into account the sulfur content of the fuel oil produced by each refinery.

Table 7.5 Energy and materials requirements for the fuel oil chain

Parameter	**Units**	**Cadereyta**	**Madero**	**Minatitlán**	**Salamanca**	**Salina Cruz**	**Tula**
Fuel oil density	kg/liter	0.999	0.996	0.996	0.996	1.001	0.999
Sulfur content	%	3.90	4.40	3.85	3.50	4.00	3.77
Fuel oil heat content	MJ/kg	42.00	41.38	41.60	41.84	42.10	42.00
Fuel oil requirements	$kg_{fuel\ oil}/ton_{fuel\ oil}$	25.3[a]	25.3[a]	25.3[a]	25.3[a]	25.3[a]	25.3[a]
Refinery gas requirements	$kg_{gas}/ton_{fuel\ oil}$	42.8[b]	42.8[b]	42.8[b]	42.8[b]	42.8[b]	42.8[b]
Electricity requirements	$GJ/tonf_{uel\ oil}$	0.14[c]	0.14[c]	0.14[c]	0.14[c]	0.14[c]	0.14[c]
Refinery factor	$ton_{crude\ oil}/ton_{fuel\ oil}$	1.07[d]	1.07[d]	1.07[d]	1.07[d]	1.07[d]	1.07[d]
Electricity requirements	$kWh/ton_{crude\ oil}$	36.34	36.34	36.34	36.34	36.34	36.34
Energy factor for fuel oil		1.00[e]	1.00[e]	1.00[e]	1.00[e]	1.00[e]	1.00[e]
Electricity factor for fuel oil		1.00[f]	1.00[f]	1.00[f]	1.00[f]	1.00[f]	1.00[f]

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirtschaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

[a] PSEL-LCA Study, Chapter IV.9.5.4, Table IV.9.15, page 141. The values are: 25.3 for Europe, 8.5 for Raffoil, 11.2 for Swiss RSO and 29.4 for CIS.

[b] PSEL-LCA Study, Chapter IV.9.5.4, Table IV.9.15, page 141. The values are: 42.8 for Europe, 33.2 for Raffoil, 47.4 for Swiss RSO and 47.8 for CIS.

[c] PSEL-LCA Study, Chapter IV.9.5.4, Table IV.9.15, page 141. The values are: 0.14 for Europe, 0.117 for Raffoil, zero for Swiss RSO and 0.658 for CIS.

[d] PSEL-LCA Study, Chapter IV.9.3.1, Table IV.9.6, page 135. The values are for Europe and include different values for different products.

[e] PSEL-LCA Study, Chapter IV.9.5.5, Table IV.9.17, page 143. This factor is the ratio of energy requirements of refined products to energy requirements of entire refinery, provided for different products (diesel 0.5, gasoline 2.0, kerosene 0.5, LPG 1.5, bitumen 0.5, heavy fuel oil 1.0 and refinery gas 1.0).

[f] PSEL-LCA Study, Chapter IV.9.5.5, Table IV.9.17, page 143. This factor is the ratio of electricity requirements of refined products to electricity requirements of entire refinery, provided for different products (diesel 0.5, gasoline 1.5, kerosene 0.5, LPG 1.5, bitumen 1.0, heavy fuel oil 1.0 and refinery gas 1.0).

7.2.6. Fuel oil transportation (Level V)

Pipeline, ship, train and truck perform fuel oil transportation from the processing facilities to the power utilities. The type of transportation depends on the specific power utility location, the transport infrastructure and logistics considerations.

Due to the fact that the WASP model is a one-node model, and that the Mexican electric system is a very scattered system of power utilities it was necessary to put the power utilities into several groups (see Chapter 4) according to similar installed capacities. This solves the problem represented by the one node limitation of WASP; however it gives rise to several problems in the transportation step from the refinery to the power plant. Of course, these problems would not be present with a several node WASP version, since, in that case, WASP could handle a regional electrical system, avoiding, in principle, the problem of different transportation modes.

These problems are present in the steam and turbo gas plants. In order to deal with these problems we made an additional assumption. This assumption was to keep the grouping of the power plants and consider the actual transportation mode and traveled distance, as well as, fuel's volume transported, the emission factors of the fuel used in each transportation mode and the amount of fuel consumed in the transportation mode per ton of fuel oil transported and per kilometre and estimate an equivalent distance for the group.

Clearly, this procedure will give us different distances for the different pollutants and the criteria were to choose the distance associated with the CO_2, the major pollutant. Table 7.7 shows the estimated distances for all steam groups.

Table 7.8 shows the energy requirements and fuel oil losses during this transportation step. According to the consulted literature there are fuel oil losses due to spills and accidents. On the other hand there are electricity requirements, which contribute to the indirect emissions, as well as, those resulting from the use of diesel for the trains, trucks and ships. For the emission factors associated with this transportation step, Table 7.9 shows the values as well as the source of the factors. According to the consulted literature there are not noticeable VOC emissions from transporting heavy refined products, such as diesel and fuel oil, however there are values for gasoline and jet fuel. Therefore, there are not direct emissions for this transportation step and the factors shown in Table 7.9 are related to the auxiliary fuels -diesel and electricity- and correspond to indirect emissions.

7.2.7. Fuel oil electricity generation (Level VI)

The electricity generation step and the crude oil refining step are the more energy consuming steps of the whole oil chain. However, the electricity generation step is by all means the most energy-consuming step of these two activities in the chain. Therefore, is of the major importance to carry out a complete and detailed analysis of the data on energy consumption and emissions during this part of the chain.

The detailed analysis of the electricity generation step was carried out in the plant-level analysis of expansion alternatives (Chapter 5). For the expansion analysis it was necessary to consider, in detail, parameters such as the efficiency, heating value, specific consumption, net heat value, fuels and their characteristics, emission factors and control devices, costs, etc., for all the power plants -existing and additional- in the expansion alternatives. In consequence, the most convenient action is to refer to the reader to Chapter 5 for a detailed analysis on the relevant parameters for this step of the chain.

Table 7.6 Emission factors for the fuel oil production in the oil regining

Emission	Fuel oil combustion	Refinery gas combustion	Process-related emissions	Combined direct emission factors
	$kg/ton_{fuel\ oil}$	kg/ton_{gas}	$g/ton_{fuel\ oil}$	$kg/ton_{crude\ oil}$
Particulates (total)	3.3[a]		0.01[a]	$8.74 \times 10^{+1}$
Particulates (PM-10)				
SO_X (as SO_2)				
Cadereyta refinery	73.5[n]	4.2[i]	0.47[i]	$2.35 \times 10^{+3}$
Madero refinery	83.2[n]	4.2[i]	0.47[i]	$2.58 \times 10^{+3}$
Minatitlán refinery	72.8[n]	4.2[i]	0.47[i]	$2.33 \times 10^{+3}$
Salamanca refinery	66.2[n]	4.2[i]	0.47[i]	$2.17 \times 10^{+3}$
Salina Cruz refinery	75.3[n]	4.2[i]	0.47[i]	$2.39 \times 10^{+3}$
Tula refinery	71.1[n]	4.2[i]	0.47[i]	$2.29 \times 10^{+3}$
NO_X	5.0[b]	5.0[b]	0.028[b]	$3.44 \times 10^{+2}$
CO	0.24[c]	0.24[c]		$1.53 \times 10^{+1}$
HCl	90.0[d]	90.0[d]		$5.73 \times 10^{+3}$
HF	9.0[e]	9.0[e]		$5.73 \times 10^{+3}$
NMTOC/NMVOC	0.2[f]	0.25[f]	0.36[j]	$3.51 \times 10^{+2}$
CH_4	0.2[f]	0.25[f]	0.04[k]	$5.21 \times 10^{+1}$
VOC/TOC total	0.4[g]	0.5[g]	0.40[l]	$4.03 \times 10^{+2}$
CO_2	3110.0[h]	2870.0[h]	8.6[m]	$1.96 \times 10^{+5}$
N_2O				

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirtschaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

[a] PSEL-LCA Study, Chapter IV.9.7.5, Table IV.9.32, page 151. The values are: Fuel oil combustion (3.3 for Europe, 1.7 for Raffoil, 1.1 for Swiss RSO and 3.3 for CIS), Process-related emissions (0.01 for Europe, Raffoil, Swiss RSO and CIS).

[b] PSEL-LCA Study, Chapter IV.9.7.4, Table IV.9.30, page 150. The values are: Fuel oil combustion (5.0 for Europe, 3.0 for Raffoil, 7.0 for Swiss RSO and 5.0 for CIS); Refinery gas combustion (5.0 for Europe and CIS, 3.0 for Raffoil, 7.0 for Swiss

[c] PSEL-LCA Study, Chapter IV.9.7.2, Table IV.9.27, page 149. The values are: 0.24 for Europe, 0.15 for Raffoil, and Swiss RSO and 3.3 for CIS.

[d] PSEL-LCA Study, Chapter IV.9.7.7, Table IV.9.37, page 153. The values are: 90.0 for all refineries.

[e] PSEL-LCA Study, Chapter IV.9.7.7, Table IV.9.37, page 153. The values are: 9.0 for all refineries.

[f] PSEL-LCA Study, Chapter IV.9.7.6, Table IV.9.36, page 153. The values are: 50% methane in VOC.

[g] PSEL-LCA Study, Chapter IV.9.7.6, Table IV.9.36, page 153. The values are: Fuel oil combustion (0.4 Europe, Swiss RSO and CIS, 0.04 Raffoil), Refinery gas combustion (0.5 Europe, Swiss RSO and CIS, 0.04 Raffoil).

[h] PSEL-LCA Study, Chapter IV.9.7.1, Table IV.9.26, page 148. The values are: Fuel oil combustion (3110 for Europe and CIS, 3220 for Raffoil and Swiss RSO), Refinery gas combustion (2870 for Europe and CIS, 2750 for Raffoil and Swiss RSO).

[i] PSEL-LCA Study, Chapter IV.9.7.3, Table IV.9.29, page 150. The values are: Refinery gas combustion (4.2 for Europe, 0.05 for Raffoil, 2.0 for Swiss RSO and 4.2 for CIS), Process-related emissions (0.47 for Europe and CIS, 0.0 for Raffoil and Swiss

[j] PSEL-LCA Study, Chapter IV.9.7.6, Table IV.9.35, page 152. The values are: 0.36 for Europe, 0.4 for Raffoil, 0.61 for Swiss RSO and 10 for CIS.

[k] PSEL-LCA Study, Chapter IV.9.7.6, Table IV.9.35, page 152. The values are: 0.04 for Europe, 0.05 for Raffoil, 0.07 for Swiss RSO and 1.0 for CIS.

[l] PSEL-LCA Study, Chapter IV.9.7.6, Table IV.9.35, page 152. The values are: 0.4 for Europe, 0.45 for Raffoil, 0.68 for Swiss RSO and 11 for CIS.

[m] PSEL-LCA Study, Chapter IV.9.7.1, Table IV.9.26, page 148. The values are: 8.6 for Europe, 8.3 for Raffoil and Swiss RSO and 14.4 for CIS.

Source: USEPA, Air Pollution Emission Factors, Vol. I, Stationary Point and Area Sources, AP-42, 5th edition, November 1996.

[n] USEPA AP-42 provides the formula 157*sulfur content, to convert to kg/1000 liters multiply by 0.12 and by the inverse of the fuel oil density to convert to kg/ton of fuel oil.

Table 7.7 Estimated transportation distances, fuel oil chain (step V)

Steam	V350	V300	V250	V160	V150	V082	V075	V036
	km	km	km	km	km	km	km	km
Estimated distance	596.7	1309.2	19.5	503.3	79.6	228.7	34	1065.5

Table 7.8 Energy requirements and fuel oil losses in step V

	Unit	V350	V300	V250	V160	V150	V082	V075	V036
		ship	pipeline	pipeline	train	truck	pipeline	pipeline	train
Fuel oil losses	$g_{fuel\ oil}/tonf_{uel\ oil}$	0.0[b]	2.3[a]	2.3[a]	0.0[g]	0.0[g]	2.3[a]	2.3[a]	0.0[g]
Fuel oil losses	$g_{fuel\ oil}l/ton_{fuel\ oil}$ - km	0.0[b]	0.00102	0.00223	0.0[g]	0.0[g]	0.00102	0.00152	0.0[g]
Electricity requirements	kWh/$ton_{fuel\ oil}$ - km		0.020[d]	0.020[d]			0.020[d]	0.020[d]	
Diesel requirements	$g_{diesel}/ton_{fuel\ oil}$ - km	12.0[c]			4.7[e]	0.024[f]			4.7[e]
Diesel requirements	$l_{diesel}/ton_{fuel\ oil}$ - km	0.0142			0.0056	0.0285			0.0056

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirtschaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

[a] PSEL-LCA Study, Chapter IV.8.8.6, page 110. The values are: 2.3 g/ton for all regions except CIS in which the value is 154 g/ton. Values are for crude oil losses, assumed to be the same for refined products as these losses are related to spills/accidents.

[b] No information for inland barges. Accidents data only available for large ocean vessels/tankers. The PSEL-LCA Study, Chapter IV.8.9.6, page 118 indicates 0.8 kg/ton for ocean-going tankers.

[c] PSEL-LCA Study, Chapter IV.8.10.5, page 121. Indicates 12 g/ton-km for inland barges.

[d] PSEL-LCA Study, Chapter IV.8.8.3, Table IV.8.22, page 108. The range for onshore pipelines is 17-33 Wh/ton - km. The Swiss Study used a value of 20. In the same page are reported values for offshore pipelines.

[e] PSEL-LCA Study, Appendix B, Table B.2.2, page 32. Indicates 4.7 g/ton-km for average diesel trains.

[f] PSEL-LCA Study, Appendix B, Table B.1.5, page 5. Indicates 0.024 kg/ton-km for large trucks with total weight of 40 ton, value for 28 ton truck is 0.034; value for 16 ton truck is 0.08.

[g] No information for these transport modes.

7.2.8. Diesel chain (Level IV)

Since fuel oil and diesel are two by products of the crude oil refining process, the energy parameters and emission factors associated with the step of crude oil production (step II) will be the same as those for the fuel oil chain.

For the discussion of this step of the diesel chain we refer to the reader to Tables 7.1 to 7.3, comments and assumptions of section 7.2.1.. Therefore some of the previous Tables are also applicable to the diesel chain. Due to this consideration we will just call for the Tables and comments expressed in the corresponding section of the fuel oil chain.

Table 7.9 Emission factors for the fuel oil transportation (step V)

Emission	Emission factors					
	Electricity for pipeline[a]	Diesel (barge/tanker/ship)[b]		Diesel train[b]	Diesel truck	
	g/kWh	$g/ton_{fuel\ oil}$ - km	g/l_{diesel}	g/l_{diesel}	g/kg_{diesel}	g/l_{diesel}
Particulates (total)	$1.202 \times 10^{+1}$	$3.000 \times 10^{+0}$	$2.108 \times 10^{+0}$	$3.000 \times 10^{+0}$	15.61[c]	$1.316 \times 10^{+1}$
Particulates (PM-10)	$2.917 \times 10^{+0}$					
SO_X (as SO_2)	$1.174 \times 10^{+1}$	$3.100 \times 10^{+0}$	$2.178 \times 10^{+0}$	$6.800 \times 10^{+0}$		
NO_X	$1.534 \times 10^{+0}$	$3.000 \times 10^{+1}$	$2.108 \times 10^{+1}$	$4.400 \times 10^{+1}$	41.00[e]	$3.457 \times 10^{+1}$
CO	1.504×10^{-1}	$1.700 \times 10^{+1}$	$1.194 \times 10^{+1}$	$1.600 \times 10^{+1}$	7.90[e]	$6.661 \times 10^{+0}$
HCl	4.902×10^{-2}					
HF	6.027×10^{-3}					
NMTOC/NMVOC	1.479×10^{-2}	$4.000 \times 10^{+0}$	$2.811 \times 10^{+0}$		3.80[e]	$3.204 \times 10^{+0}$
CH_4	1.528×10^{-2}	$3.000 \times 10^{+0}$	$2.108 \times 10^{+0}$		0.12[e]	$1.012 \times 10^{+1}$
VOC/TOC total	3.007×10^{-2}	$7.000 \times 10^{+0}$	$4.918 \times 10^{+0}$		3.92[e]	$3.305 \times 10^{+0}$
CO_2	$5.877 \times 10^{+2}$	$3.800 \times 10^{+3}$	$2.670 \times 10^{+3}$	$2.659 \times 10^{+3}$	2659.11[f]	$2.242 \times 10^{+3}$
N_2O	4.313×10^{-3}				0.08[d]	7.109×10^{-2}

Source: USEPA, Air Pollution Emission Factors, Vol. I, Stationary Point and Area Sources, AP-42, 5th edition, November 1996.

[a] These emission factors were estimated by a weighting procedure of the USEPA emission factors for electricity generation per type of technology and fuel. The weighting factor is the conversion factor per fuel and generation technology over the total generation for year 1998, the base year.

Source: USEPA, Air Pollution Emission Factors, Vol. I, Mobile Sources, AP-42, 5th edition, November 1996.

[b] USEPA AP-42 provides values for different mobile sources and fuels.

Source: USEPA, Part 5 draft User Guide, Figure 1.8, HDDV particulate emission factors of 1.583 1.38 g/mi for 1994; Part 5 Appendix to draft User Guide, Table 2, PM emission factors in g/bhp-hr for different model years; IPCC Guidelines Reference Manual, Table 1-39, page 1.82, 3.3 km/liter for fuel efficiency HDDV.

[c] We use average value for the HDDV particulate emission factor; also we use values for 1994 and 1988/90 to scale to 1988/90 using 0.0836 (1994) and 0.436 (1988/90); convert to km from miles and the fuel efficiency for HDDV from IPCC.

[d] IPCC Guidelines Reference Manual, Table 1-39, page 1.82, indicates a value of 0.1 g/kg for N_2O.

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirtschaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

[e] PSEL-LCA Study, Appendix B, Table B.1.6, page 6. Indicates 41 for NO_X; 3.8 for NMVOC; 0.12 for CH_4 and 7.9 for CO.

[f] Calculated on the basis of an 86.01% carbon content of auxiliary fuel (diesel) and a diesel density of 1186 liters/ton.

7.2.9. *Diesel transportation (Level III)*

As in the fuel oil chain, the second main assumption was to take into account just the pipelines from the marine regions and their length up to the coastal terminal of Dos Bocas and from there to the distribution centre of Nuevo Teapa and finally to each one of the processing centres. The offshore pipeline length to Dos Bocas terminal was estimated in 163.2 km; form Dos Bocas terminal to Nuevo Teapa distribution centre was estimated in 144 km. To these distances we have to add the pipeline length up to each one of the processing facilities.

These facilities are located at the southeast, central and northeast parts of the country. However, for the expansion analysis it was necessary to group 27 power plants with 59 generation units and capacities between 44 and 12 MW into three general groups (TG42, TG30 and TG14). These generation units are scattered along the whole country, 35 consume diesel, 20 natural gas and diesel and 4 natural gas. Therefore, it was necessary to assign them an input fuel type and a supply processing facility. Since most of the generation units consume diesel and this fuel has a more flexible transportation infrastructure, than natural gas, it was decided to use diesel as fuel type for these plant's grouping.

Finally, the diesel supply processing facility was select as the Tula’s refinery. The reason was that this facility is located near the geographical center of the group of generation plants. The crude oil pipeline that supplies crude oil to this refining facility has an average length of 923 km. It is important to recognize that part of this pipeline length is offshore and part is onshore. This was taken into account in the data preparation.

For step III, we need data on the crude oil losses, the electricity requirements and diesel requirements for the offshore pipeline part. Again, the PSEL-LCA, 1996, provides us with the required information. Two contributions have to be considered in this step since we have direct and indirect contributions to the emission. Direct contributions are the result of the NMTOC/NMVOC, methane and VOC/TOC total (NMTOC + methane). Indirect contributions are originated in the electricity that is used and the diesel consumed by the diesel engines in the offshore facilities. These factors are shown in Table 7.10.

7.2.10. *Crude oil processing in the diesel chain (Level IV)*

For this step of the diesel chain, some energy parameters will change in comparison with the fuel oil case. Specifically, the parameters that are different are: diesel density, heat content, energy factor for diesel, electricity factor for diesel, electricity requirements and the refinery factor. The energy and emission factors are shown in Table 7.11 and 7.13.

7.2.11. *Diesel transportation (Level V)*

Pipeline, ship, train and truck perform diesel transportation from the processing facilities to the power utilities. The type of transportation depends on the specific power utility location, the transport infrastructure and logistics considerations.

As in the case of the fuel oil chain, in this step of the diesel chain, we also face the same type of problems originated by the expansion grouping of power plants and the different transportation modes for diesel. In order to solve these problems we made the same assumptions as in the fuel oil chain, section 7.2.1. and follow the same procedure for the estimation of the diesel transportation distances. Taking into account that the processing centre that provides diesel to this group of power plants is the Tula's refinery, the estimated average distances for diesel transportation to the power plants are shown in Table 7.14. Tables 7.12 and 7.15 showed the energy parameters and emission factors for the diesel transportation from the crude oil processing facilities to the power plants.

Table 7.10 Energy requirements, crude oil losses and emission factors for step III

Crude oil losses	2.3[a]	g/ton$_{crude\ oil}$			
Energy requirements					
Electricity requirements	20.0[b]	Wh/ton$_{crude\ oil}$ - km			
Diesel requirements[c]	4.40×10^{-7}	TJ/ton$_{crude\ oil}$ - km			
Diesel heat content	45.50	MJ/kg			
Diesel density	0.85	kg/liter			
Emission factors	**Emission factor direct g/ton$_{crude\ oil}$**	**Emission factor direct g/ton$_{crude\ oil}$ - km**	**Auxiliary electricity[e] onshore pipeline g/kWh**	**Large diesel[f] engines g/GJ**	**Auxiliary diesel offshore pipeline g/liter**
Particulates (total)			$1.202 \times 10^{+1}$	$3.000 \times 10^{+1}$	$1.158 \times 10^{+0}$
Particulates (PM-10)			$2.917 \times 10^{+0}$	$2.470 \times 10^{+1}$	9.532×10^{-1}
SO_X (as SO_2)			$1.174 \times 10^{+1}$	$4.340 \times 10^{+2}$	$1.675 \times 10^{+1}$
NO_X			$1.534 \times 10^{+0}$	$1.322 \times 10^{+3}$	$5.102 \times 10^{+1}$
CO			1.504×10^{-1}	$3.490 \times 10^{+2}$	$1.347 \times 10^{+1}$
HCl			4.902×10^{-2}		
HF			6.027×10^{-3}		
NMTOC/NMVOC	16.38[d]	5.908×10^{-3}	1.479×10^{-2}	$3.490 \times 10^{+1}$	$1.347 \times 10^{+0}$
CH_4	1.62[d]	5.844×10^{-4}	1.528×10^{-2}	$3.102 \times 10^{+0}$	1.197×10^{-1}
VOC/TOC total (NMTOC + CH_4)	18.00[d]	6.493×10^{-3}	3.007×10^{-2}	$3.800 \times 10^{+1}$	$1.466 \times 10^{+0}$
CO_2			$5.877 \times 10^{+2}$	$7.094 \times 10^{+4}$	$2.738 \times 10^{+3}$
N_2O			4.313×10^{-3}		

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirtschaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

[a] PSEL-LCA Study, Chapter IV.8.8.6, page 110. The values are: 2.3 g/ton for all regions except in the CIS where the value is 154 g/ton.

[b] PSEL-LCA Study, Chapter IV.8.8.3, Table IV.8.22, page 108. The range for onshore pipelines is 17-33 Wh/ton - km. The Swiss Study used a value of 20. In the same page are reported values for offshore pipelines.

[c] PSEL-LCA Study, Chapter IV, Table IV.8.24, page 109.

[d] PSEL-LCA Study, Chapter IV, Table IV.8.19, page 105. General VOC emissions from crude oil transport is 18 g/ton with a 9% methane content (range of 0.5 - 25), we use 9% methane content.

Source: USEPA, Air Pollution Emission Factors, Vol. I, Stationary Point and Area Sources, AP-42, 5th edition, November 1996.

[e] These emission factors were estimated by a weighting procedure of the USEPA emission factors for electricity generation per type of technology and fuel. The weighting factor is the conversion factor per fuel and generation technology over the total

[f] USEPA AP42 provides values for the emission factor for Uncontrolled Large Diesel Engines under the Large Stationary Engines, EDE-2.

7.2.12. Diesel electricity generation (Level VI)

The electricity generation step and the crude oil refining step are the more energy consuming steps of the whole oil chain. However, the electricity generation step is, by all means, the most energy-consuming step of these two activities in the chain. Therefore, is of the major importance to carry out a complete and detailed analysis of the data on energy consumption and emissions during this part of the chain.

The detailed analysis of the electricity generation step was carried out in the plant-level analysis of expansion alternatives (Chapter 5). For the expansion analysis it was necessary to consider, in detail, parameters such as the efficiency, heating value, specific consumption, net heat value, fuels and their characteristics, emission factors and control devices, costs, etc., for all the power plants -existing and additional- in the expansion alternatives. In consequence, the most convenient action is to refer to the reader to Chapter 5 for a detailed analysis on the relevant parameters for this step of the chain.

Table 7.12 Energy requirements and diesel losses in diesel chain (step V)

	Unit	TG42 pipeline	TG30 truck	TG14 truck
Diesel losses	g_{diesel}/ton_{diesel}	2.3[a]	0.0[g]	0.0[d]
Diesel losses	g_{diesel}/ton_{diesel} - km	0.0008	0.0[g]	0.0[d]
Electricity requirements	kWh/ton_{diesel} - km	0.020[b]		
Diesel requirements	g_{diesel}/ton_{diesel} - km		0.024[c]	0.024[c]
Diesel requirements	l_{diesel}/ton_{diesel} - km		0.0285	0.0285

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirtschaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

(a) PSEL-LCA Study, Chapter IV.8.8.6, page 110. The values are: 2.3 g/ton for all regions except CIS in which the value is 154 g/ton. Values are for crude oil losses, assumed to be the same for refined products as these losses are related to spills/accidents.

(b) PSEL-LCA Study, Chapter IV.8.8.3, Table IV.8.22, page 108. The range for onshore pipelines is 17-33 Wh/ton - km. The Swiss Study used a value of 20. In the same page are reported values for offshore pipelines.

(c) PSEL-LCA Study, Appendix B, Table B.1.5, page 5. Indicates 0.024 kg/ton-km for large trucks with total weight of 40 ton, value for 28 ton truck is 0.034; value for 16 ton truck is 0.08.

(d) No information for these transport modes.

7.2.13. Natural gas chain

Natural gas, as a resource can be present in natural gas fields or associated to oil. In the case of Mexico oil and natural gas resources are located onshore and offshore. At present most of the oil and natural gas production comes from the marine oil fields, located in the Gulf of Mexico. Most of the present production of natural is associated to oil.

Mexican natural gas is extracted from onshore and offshore gas fields. Onshore natural gas production dominates (Chapter 3, Table 3.14)). Associated natural gas contributes with the main portion to the total natural gas production of the country. Associated natural gas is extracted from both regions, marine and main land.

Table 7.13 Emission factors for the diesel production in the oil refining

Emission	Fuel oil combustion	Refinery gas combustion	Process-related emissions	Combined direct emission factors
	$kg/ton_{fuel\ oil}$	kg/ton_{gas}	g/ton_{diesel}	$kg/ton_{crude\ oil}$
Particulates (total)	3.3[a]		0.01[a]	$4.98 \times 10^{+1}$
Particulates (PM-10)				
SO_X (as SO_2)	44.0[n]	4.2[i]	0.47[i]	$1.07 \times 10^{+3}$
NO_X	5.0[b]	5.0[b]	0.028[b]	$1.91 \times 10^{+2}$
CO	0.24[c]	0.24[c]		$7.86 \times 10^{+0}$
HCl	90.0[d]	90.0[d]		$2.95 \times 10^{+3}$
HF	9.0[e]	9.0[e]		$2.95 \times 10^{+2}$
NMTOC/NMVOC	0.2[f]	0.25[f]	0.36[j]	$3.54 \times 10^{+2}$
CH_4	0.2[f]	0.25[f]	0.04[k]	$4.60 \times 10^{+1}$
VOC/TOC total	0.4[g]	0.5[g]	0.40[l]	$4.00 \times 10^{+2}$
CO_2	3110.0[h]	2870.0[h]	8.6[m]	$1.05 \times 10^{+5}$
N_2O				

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirtschaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

(a) PSEL-LCA Study, Chapter IV.9.7.5, Table IV.9.32, page 151. The values are: Fuel oil combustion (3.3 for Europe, 1.7 for Raffoil, 1.1 for Swiss RSO and 3.3 for CIS); Process-related emissions (0.01 for Europe, Raffoil, Swiss RSO and CIS).

(b) PSEL-LCA Study, Chapter IV.9.7.4, Table IV.9.30, page 150. The values are: Fuel oil combustion (5.0 for Europe, 3.0 for Raffoil, 7.0 for Swiss RSO and 5.0 for CIS); Refinery gas combustion (5.0 for Europe and CIS, 3.0 for Raffoil, 7.0 for Swiss RSO); Process-related emissions (0.028 for Europe and CIS, 0.013 for Raffoil and 0.024 for Swiss RSO).

(c) SEL-LCA Study, Chapter IV.9.7.2, Table IV.9.27, page 149. The values are: 0.24 for Europe, 0.15 for Raffoil, and Swiss RSO and 3.3 for CIS.

(d) PSEL-LCA Study, Chapter IV.9.7.7, Table IV.9.37, page 153. The values are: 90.0 for all refineries.

(e) PSEL-LCA Study, Chapter IV.9.7.7, Table IV.9.37, page 153. The values are: 9.0 for all refineries.

(f) PSEL-LCA Study, Chapter IV.9.7.6, Table IV.9.36, page 153. The values are: 50% methane in VOC.

(g) PSEL-LCA Study, Chapter IV.9.7.6, Table IV.9.36, page 153. The values are: Fuel oil combustion (0.4 Europe, Swiss RSO and CIS, 0.04 Raffoil); Refinery gas combustion (0.5 Europe, Swiss RSO and CIS, 0.04 Raffoil).

(h) PSEL-LCA Study, Chapter IV.9.7.1, Table IV.9.26, page 148. The values are: Fuel oil combustion (3110 for Europe and CIS, 3220 for Raffoil and Swiss RSO), Refinery gas combustion (2870 for Europe and CIS, 2750 for Raffoil and Swiss RSO).

(i) PSEL-LCA Study, Chapter IV.9.7.3, Table IV.9.29, page 150. The values are: Refinery gas combustion (4.2 for Europe, 0.05 for Raffoil, 2.0 for Swiss RSO and 4.2 for CIS), Process-related emissions (0.47 for Europe and CIS, 0.0 for Raffoil and Swiss RSO).

(j) PSEL-LCA Study, Chapter IV.9.7.6, Table IV.9.35, page 152. The values are: 0.36 for Europe, 0.4 for Raffoil, 0.61 for Swiss RSO and 10 for CIS.

(k) PSEL-LCA Study, Chapter IV.9.7.6, Table IV.9.35, page 152. The values are: 0.04 for Europe, 0.05 for Raffoil, 0.07 for Swiss RSO and 1.0 for CIS.

(l) PSEL-LCA Study, Chapter IV.9.7.6, Table IV.9.35, page 152. The values are: 0.4 for Europe, 0.45 for Raffoil, 0.68 for Swiss RSO and 11 for CIS.

(m) PSEL-LCA Study, Chapter IV.9.7.1, Table IV.9.26, page 148. The values are: 8.6 for Europe, 8.3 for Raffoil and Swiss RSO and 14.4 for CIS.

(n) PSEL-LCA Study, Chapter IV.9.7.3, Table IV.9.29, page 150. The values are: 44.0 for Europe, 16.4 for Raffoil, Swiss RSO 10.0 and 44.0 for CIS.

Burgos region, located at the northeast part of the country, is becoming an important natural gas production zone, however its importance will depend on the amount of proved reserves and the available infrastructure (presently and in the future) for production and transportation.

Once crude oil and natural gas has been separated, at the separation batteries, natural gas is sent, through pipelines, to the storage and distribution facilities for shipment into the processing gas plants and preparation for distribution to the customers.

The impacts from the gas chain for electricity generation are associated with the overall activities for the gas exploration, production, processing and transportation (Appendix IV). During natural gas extraction, there are some leaks. Since natural gas is mainly methane, a strong greenhouse gas, there are some concerns that these leakages can add to the possible risks of global warming.

Natural gas, with a carbon to energy ratio that is less than half that of coal, and about two-thirds that of oil, may receive strong attention as a fuel for generating electricity, as is the case at present, when there is need to minimize CO_2 emissions. So far as the greenhouse effect is concerned, this advantage may be put in jeopardy due to releases of methane during the gas extraction, transportation and handling. Therefore, it is necessary to consider the full energy chain and consider that there are options for the reduction of such methane losses.

Besides the already mentioned sources of pollution of air and water (Appendix IV), for the analysis we have to take into account other sources of contamination under normal conditions of operation. These additional sources of emissions are related to the energy uses for extraction, re-injection and other services that are needed for the separation of oil and natural gas and its shipment into the storage facilities. Compressors, electricity generators and other equipment require a source of energy for its operations. Electricity, diesel and natural gas can provide the required energy for this equipment. Normally, for their operations, offshore facilities employ diesel generators to produce the required electricity and mechanical work.

Table 7.14 Estimated transportation distances, diesel chain (step V)

Turbogas	**TG42**	**TG30**	**TG14**
	km	km	km
Estimated distance	1836	1926	1759

From the DECADES point of view the structure of the natural gas chain is quite similar to the oil chain shown in Figure 7.2. The main differences lie in the processing step (Appendix IV) and the transportation steps. A very important difference is that in a gas chain the user cannot define emission factors for natural gas as an auxiliary fuel. These emissions have to be entered as direct factors.

7.2.14. Natural gas production (Level II)

In principle, for the estimation of the emission factors of this step we consider three elements of contribution: gas leakage, flaring and compressors. However, since there was no possibility to confirm the emission factor for gas leakage, therefore it was not included. A fourth element was considered, emissions from diesel consumption for construction of production facilities, but not included into the database for the study. Under these assumptions, Table 7.16 shows the energy factors and emission factors for the gas production step.

Table 7.15 Energy requirements and diesel losses in diesel chain (step V)

Emission	Emission factors		
	Electricity for pipeline[a]	Diesel truck	
	g/kWh	g/kg_{diesel}	g/l_{diesel}
Particulates (total)	$1.202 \times 10^{+1}$	15.61[b]	$1.316 \times 10^{+1}$
Particulates (PM-10)	$2.917 \times 10^{+0}$		
SO_X (as SO_2)	$1.174 \times 10^{+1}$		
NO_X	$1.534 \times 10^{+0}$	41.00[d]	$3.457 \times 10^{+1}$
CO	1.504×10^{-1}	7.90[d]	$6.661 \times 10^{+0}$
HCl	4.902×10^{-2}		
HF	6.027×10^{-3}		
NMTOC/NMVOC	1.479×10^{-2}	3.80[d]	$3.204 \times 10^{+0}$
CH_4	1.528×10^{-2}	0.12[d]	$1.012 \times 10^{+1}$
VOC/TOC total	3.007×10^{-2}	3.92[d]	$3.305 \times 10^{+0}$
CO_2	$5.877 \times 10^{+2}$	2659.11[e]	$2.242 \times 10^{+3}$
N_2O	4.313×10^{-3}	0.08[c]	7.109×10^{-2}

Source: USEPA, Air Pollution Emission Factors, Vol. I, Stationary Point and Area Sources, AP-42, 5th edition, November 1996.

[a] These emission factors were estimated by a weighting procedure of the USEPA emission factors for electricity generation per type of technology and fuel. The weighting factor is the conversion factor per fuel and generation technology over the total generation for year 1998, the base year.

Source: USEPA, Part 5 draft User Guide, Figure 1.8, HDDV particulate emission factors of 1.583 1.38 g/mi for 1994; Part 5 Appendix to draft User Guide, Table 2, PM emission factors in g/bhp-hr for different model years; IPCC Guidelines Reference Manual, Table 1-39, page 1.82, 3.3 km/liter for fuel efficiency HDDV.

[b] We use average value for the HDDV particulate emission factor; also we use values for 1994 and 1988/90 to scale to 1988/90 using 0.0836 (1994) and 0.436 (1988/90); convert to km from miles and the fuel efficiency for HDDV from IPCC.

[c] IPCC Guidelines Reference Manual, Table 1-39, page 1.82, indicates a value of 0.1 g/kg for N_2O.

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirtschaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

[d] PSEL-LCA Study, Appendix B, Table B.1.6, page 6. Indicates 41 for NO_X; 3.8 for NMVOC; 0.12 for CH_4 and 7.9 for CO.

[e] Calculated on the basis of an 86.01% carbon content of auxiliary fuel (diesel) and a diesel density of 1186 liters/ton.

Table 7.16 Energy parameters and emission factors for gas production (step II)

	Gas flaring	Gas consumption for compressors
Amount of gas flared[a]	0.0025 $m^3_{gas\ flared}/m^3_{gas\ produced}$	
Gas consumption in compressors[c]		0.33 %
Natural gas heat content	0.0392 GJ/m^3	0.0392 GJ/m^3

Emission	Gas flaring		Gas consumption for compressors		Total for step II
	$g/m^3_{natural\ gas\ in\ the\ flare}$	$g/m^3_{natural\ gas}$	ng/J[d]	$g/m^3_{natural\ gas}$	$g/m^3_{natural\ gas}$
Particulates (total)			$1.802 \times 10^{+1}$	2.35×10^{-3}	2.35×10^{-3}
Particulates (PM-10)			$1.802 \times 10^{+1}$	2.35×10^{-3}	2.35×10^{-3}
SO_X (as SO_2)	0.17[b]	4.25×10^{-4}	4.04×10^{-1}	5.28×10^{-5}	4.78×10^{-4}
NO_X	0.012	3.00×10^{-5}	$1.45 \times 10^{+2}$	1.89×10^{-2}	1.90×10^{-2}
CO			$7.10 \times 10^{+1}$	9.28×10^{-3}	9.28×10^{-3}
HCl					
HF					
NMTOC/NMVOC	0.003	7.50×10^{-6}	8.60×10^{-1}	1.12×10^{-4}	1.20×10^{-4}
CH_4	0.006	1.50×10^{-5}	$2.19 \times 10^{+1}$	2.86×10^{-3}	$3.77 \times 10^{+0}$
VOC/TOC total	0.009	2.25×10^{-5}	$2.28 \times 10^{+1}$	2.98×10^{-3}	3.00×10^{-3}
CO_2	2.0	5.00×10^{-3}	$4.7424 \times 10^{+4}$	$6.20 \times 10^{+0}$	$6.20 \times 10^{+0}$
N_2O					

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirtschaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

[a] PSEL-LCA Study, Chapter V.6.3.4, Table V.6.9, page 20. For associated gas the values are: Europe (0.013), CIS (0.025), and Algeria (0.017); flaring is done by flaring of excess gas, flaring of gas during the drilling, during the startup of a new field, during repair work and accidents, and during pressure spikes. We assume these are kg of pollutant per cubic meter of gas input into the flare.

[b] PSEL-LCA Study, Chapter V.6.3.4, Table V.6.9, page 20. Indicates 0.17 for sour gas and zero for sweet gas.

[c] PSEL-LCA Study, Chapter V.6.3.3, Table V.6.6, page 18. For natural gas production, collection, transport to processing, and compression at processing plant; we assume a breakdown of 1/3 for steps II, III and IV.

Source: USEPA, Air Pollution Emission Factors, Vol. I, Stationary Point and Area Sources, AP-42, 5th edition, November 1996.

[d] USEPA AP-42 provides these values for gas compressors, all of them in ng/J.

7.2.15. Natural gas transportation (Level III)

Natural gas consists of methane and other hydrocarbon compounds, and usually is transported in gaseous form through pipelines. The primary risks with gas pipelines are associated with fires and explosions, in particular from pipelines passing through or near heavily populated areas. In addition, pipeline leakage of methane, a strong greenhouse gas, contributes to the potential risks of climate change and global warming.

For ocean transport, natural gas is cooled to its liquid state (liquefied natural gas, LNG) for transport by special LNG tankers. The main environmental effects associated with natural gas liquefaction plants are the discharge of heat to the atmosphere or to fresh or marine waters, depending on the type of cooling system used, and the occasional emission or flaring of some components extracted during gas liquefaction. There is also a possibility of destructive evaporation of LNG if it comes in contact with water.

Natural gas exports started in 1993, mainly to the United States. The amount is marginal in comparison with the total production. Imports are relatively small, however they are bigger than exports, approximately, by a factor of four. In Mexico, transportation of imported and exported natural gas is carried out by pipeline. According to the available information there is no any amount of natural gas transported by LNG tankers.

In the case of Mexico the natural gas fields are located in the Gulf of Mexico (marine regions), the states of Tabasco, Veracruz, Campeche and Tamaulipas. Most (8) of the processing centres (10) are located in the states of Veracruz (south part of the state), Tabasco and Campeche. The remaining centres are in the north part of the state of Tamaulipas and Veracruz. 74.5% of the natural gas production is extracted from the marine region, Tabasco, Campeche and south of Veracruz. The remaining 25.5% of the production is extracted from the north part of Veracruz and Tamaulipas.

The main processing and distribution centres are located in the states of Tabasco and Veracruz. Therefore, taking into account gas production level per region and distances from the production fields to the nearest processing centres, it was estimated a distance of 179 km, as an average distance from the gas fields to the processing centres.

The second assumption was a breakdown of 1/3 for steps II, III and IV in the self-consumption of natural for gas production, collection, and transport to processing and compression at processing plant. With these assumptions, Table 7.17 shows the energy requirements and emission factors for step III within the DECADES methodology.

7.2.16. Natural gas processing (Level IV)

The most common gas sweetening process for sour gas processing is described in Appendix IV. The purpose of the sweetening process is to remove the hydrogen sulfide (H_2S) from the sour gas. The H_2S removal is carry out by absorption in an amine solution. Therefore, the main assumption for the data preparation was to consider a 100% conversion of H_2S to SO_2 and to elemental sulfur. No H_2S was flared and no emissions of SO_2 per cubic meter of gas processed. 67% of the natural gas processed is sour gas and the H_2S content in the natural gas was assumed to be 2%. Also the natural gas self-consumption for natural gas treatment was assumed to be 0.02 m^3 natural $_{gas}/m^3$ natural gas produced. Finally, the losses of natural gas during natural gas treatment were considered as similar to the European case, that is, 0.013 m^3 natural gas/m3 natural gas produced. With this set of assumptions, Table 7.18 shows the energy requirements and emission factors for the processing step of natural gas chain.

Table 7.17 Energy parameters and emission factors for natural gas transportation (step III)

Gas losses/leakage in pipelines[a]	0.01	%
Gas self-consumption to run pipeline compressors[b]	2.00	% per 1000 km
Gas losses	1.00×10^{-7}	$m^3_{natural\ gas}/m^3_{natural\ gas}$ - km
Self consumption of gas	0.36	%
Gas requirements	2.00×10^{-5}	$m^3_{natural\ gas}/m^3_{natural\ gas}$ - km
Natural gas heat content	0.03920	$GJ/m^3_{gas\ natural}$

Emission	**Gas turbine compressors**[c]	**Emission factor**
	$g_{natural\ gas}/GJ$	$g_{natural\ gas}/m^3_{natural\ gas}$ - km
Particulates (total)	$1.80170 \times 10^{+1}$	1.41×10^{-5}
Particulates (PM-10)	$1.80170 \times 10^{+1}$	1.41×10^{-5}
SO_X (as SO_2)	2.58000×10^{-1}	2.02×10^{-7}
NO_X	$1.89200 \times 10^{+2}$	1.48×10^{-4}
CO	$4.73000 \times 10^{+1}$	3.71×10^{-5}
HCl		
HF		
NMTOC/NMVOC	$0.00000 \times 10^{+0}$	$0.00 \times 10^{+0}$
CH_4	$1.03200 \times 10^{+1}$	8.09×10^{-6}
VOC/TOC total	$1.03200 \times 10^{+1}$	8.09×10^{-6}
CO_2	$6.07398 \times 10^{+4}$	4.76×10^{-2}
N_2O	$1.29000 \times 10^{+0}$	1.01×10^{-6}

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirtschaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

[a] PSEL-LCA Study, Chapter V.8.4, page 38. Indicates a worldwide range of 0.001 to 0.15% of transported gas. Other sources have 600 m^3/km - year equaling about 0.01% per 1000 km.

[b] PSEL-LCA Study, Chapter V.8.3, Table V.8.4, page 37. Indicates a worldwide range of 1.4 to 3.0% per 1000 km. For West Europe and Algeria 2.00%, CIS 3.0%.

Source: USEPA, Air Pollution Emission Factors, Vol. I, Stationary Point and Area Sources, AP-42, 5th edition, November 1996.

[d] USEPA AP-42 provides these values for gas compressors, all of them in g/GJ. The exception is the CO_2 emission factor, which was calculated on the basis of the percent of carbon content in natural gas, information that was provided by the Energy Ministry of Mexico.

Table 7.18 Energy parameters and emission factors for gas processing (step IV)

H_2S content of natural gas[a]	2	mole %
Share of sour gas	67	%
Share of H_2S flared	0	%
Natural gas self-consumption for gas treatment	0.02	$m^3_{natural\ gas\ burned}/m^3_{natural\ gas\ produced}$
Natural gas losses in gas treatment[b]	0.0013	$m^3_{natural\ gas}/m^3_{natural\ gas\ produced}$

Emission	**Emission factor**[c]	**Emission factor**
	$mg/m^3_{natural\ gas\ produced}$	$g/m^3_{natural\ gas\ produced}$
Particulates (PM-10)	3.00×10^{-4}	6.00×10^{-7}
SO_X (as SO_2)	3.40×10^{-4}	6.8×10^{-2}
NO_X	2.0×10^{-3}	4.00×10^{-5}
CO	4.00×10^{-4}	8.00×10^{-7}

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirts-chaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

[a] PSEL-LCA Study, Chapter V.7.3, Table V.7.4, page 28.

[b] PSEL-LCA Study, Chapter V.7.6, page 30.

[c] PSEL-LCA Study, Chapter V.7.5, Tables V.7.6 and V.7.7, pages 29 and 30.

7.2.17. Natural gas transportation (Level V)

As in step III, the transportation mode is by pipeline, and therefore all the assumptions made for step III are applicable to the present step. However, we must remember that WASP's plant treatment of existing and additions by groups conduct us to a procedure for the estimation of the average distance for each group of plants in the expansion. This procedure was to take the actual natural gas pipeline distance to each power facility and weight them by the ratio of the consumed gas over the total gas consumption of the group of the group of plants.

The starting point for the supply was the distribution center of Ciudad Pemex in the state of Tabasco and from there each individual distance in a given group was weighted by the weighting factor of the gas consumed by the central. This was done for each of the groups of existing plants. For the additions the criteria was to consider an average distance of 300 km. Table 7.19 shows the resulting distances for this step for each of the groups. For the energy parameters and emission factors associated with this step Table 7.20 shows the values and assumptions made during the data preparation.

7.2.18. Natural gas electricity generation (Level VI)

The detailed analysis of the electricity generation step was carried out in the plant-level analysis of expansion alternatives (Chapter 5). For the expansion analysis it was necessary to consider, in detail, parameters such as the efficiency, heating value, specific consumption, net heat value, fuels and their characteristics, emission factors and control devices, costs, etc., for all the power plants -existing and additional- in the expansion alternatives. In consequence, the most convenient action is to refer to the reader to Chapter 4 for a detailed analysis on the relevant parameters for this step of the chain.

Table 7.19 Estimated transportation distances (step V)

Combined cycle					**Gas turbine**
CC240	**CC220**	**CC200**	**CC170**	**CC540**	**T122**
km	km	km	km	km	km
924.0	356.3	1345.2	2411.0	300.0	300

7.2.19. Coal chain

Coal can be mined, according to its geological setting by a variety of methods, the most common of which are underground mining (room and pillar or long-wall techniques) and surface mining (area or contour strip mining). Both underground and surface mining can cause land disturbances resulting in negative effects on the surrounding environment. Land reclamation is needed to mitigate these effects and recover degraded areas.

The large excavations associated with surface mining, as well the deposition sites for the large amounts of materials removed in order to gain access to the coal deposit, can cause dramatic changes on the landscape. Underground coal extraction also can cause significant impacts on the landscape, in particular through the land subsidence in some cases. The degree of difficulty and the time required for the impacted land to be restored depend to a large extent on the physical and topographical conditions of the site (e.g. amount of recon touring that has to be done to the land), the fertility of the soils (e.g. amount of fertilizer that has to be added), the amount and type of planting and reseeding required, and the amount of rainfall in the area. In some cases, the difficulties and costs of land restoration are greater for underground mining than for surface mining, in particular when extensive surface subsidence has occurred.

Both methods of mining can have impacts also on streams and water bodies in the surrounding areas, caused by the drainage of polluted water from the mines. All coal contains some concentration of soluble minerals that may be leached into waters draining from the mine into water bodies, thereby causing degradation of the water quality.

Measures taken to minimize the detrimental effects of mine drainage include: drainage control in the mine area; proper disposal to ensure that sulfur-bearing pyritic materials do not come in contact with water; sealing up abandoned mines to avoid leaching and drainage; and chemical treatment of acid mine drainage (alkaline neutralizing agents).

Coal mining has a number of occupational hazards. In addition to the risks of accidents in underground mines (fires, explosions, mine collapse, etc.) and in surface mines (accidents with mining machinery, wall collapse, etc.), coal miners are subject to respiratory diseases, especially pneumoconiosis, commonly known as “black-lung” disease.

Coal miners may be exposed also to an increased level of radiation exposure, arising from natural radioactive materials (mainly radon) that are released from the coal and rock during mining operations. In many countries, stringent control measures have considerably reduced exposures to radiation and to the dust precursors of black-lung disease. Another occupational hazard in coal mining arises from the high levels of noise produced by mining equipment.

Coal mining is also a source of methane gas, which is present in significant quantities in many coal seams and is released during mining. In underground mines, methane and dust pose risks of explosions. Also, the mining related emission of methane is a contributor to the atmospheric build-up of greenhouse gases arising from human activities. There are, however, possibilities to reduce methane emissions from coal mines by using methane recovery techniques.

7.2.20. Coal production (Level II)

According to the available information coal extraction in Mexico is carried out by the surface mining method. The coal production region is located in the north part of the state of Coahuila. For the estimation of the emission factors of the coal production is necessary to provide information on energy requirements (diesel and electricity) as well as the CH_4 emissions from this activity. Table 7.21 shows the energy parameters and emission factor for step II of the coal chain.

7.2.21. Coal transportation (Level III)

Also, in addition to the already mentioned emissions, there are contributions of air pollutants originated from the use of fossil fuels and electricity in the mining activities. In particular, those related with the transportation, to the next step, of the mined materials and coal (e.g. conveyor belts, truck and railroad fuels, crushing and grinding, etc.). The elements that we have to consider for the estimation of the emission factor in this step are: coal losses during transportation and fuel requirements of the transportation mode (diesel, electricity, etc.).

In Mexico train carries coal’s transportation. The auxiliary fuel for this transportation mode is diesel. Table 7.22 shows the energy parameters and emission factors for this step.

7.2.22. Coal preparation (Level IV)

Coal cleaning is accomplished by physically separating ash and sulfur-bearing pyritic material from coal (chemically bound organic sulfur to the coal is not removed). These physical beneficiation techniques are capable of removing up to 50% of the sulfur and 75% of the ash contained in the raw coal. The amount of pollution generated in the process of coal cleaning depends upon the amount of coal treated and the chemical and physical properties of the coal.

Most of the air pollution arising from coal washing is the result of drying the coal in a stream of hot gas. The pollutants are fine coal dust, ash, NO_X, SO_X, CO_2, CH_4, unburned hydrocarbons and particulate, resulting from the combustion of the coal or fossil fuels used to supply the hot gases for coal drying. Besides, coal dust and additional emissions of NO_X, SO_X, CO_2, CH_4, unburned hydrocarbons and particulate are produced during crushing and grinding of the coal.

Table 7.20 parameters and emission factors for natural gas transportation (step V)

Gas losses/leakage in pipelines[a]	0.01	%
Gas self-consumption to run pipeline compressors[b]	2.00	% per 1000 km
Gas losses	1.00×10^{-7}	$m^3_{natural\ gas}/m^3_{natural\ gas}$ - km
Self consumption of gas	0.71	%
Gas requirements	2.00×10^{-5}	$m^3_{natural\ gas}/m^3_{natural\ gas}$ - km
Natural gas heat content	0.03920	$GJ/m^3_{gas\ natural}$

Emission	**Gas turbine compressors**[c]	**Emission factor**
	$g_{natural\ gas}/GJ$	$g_{natural\ gas}/m^3_{natural\ gas}$ - km
Particulates (total)	$1.80170 \times 10^{+1}$	1.41×10^{-5}
Particulates (PM-10)	$1.80170 \times 10^{+1}$	1.41×10^{-5}
SO_X (as SO_2)	2.58000×10^{-1}	2.02×10^{-7}
NO_X	$1.89200 \times 10^{+2}$	1.48×10^{-4}
CO	$4.73000 \times 10^{+1}$	3.71×10^{-5}
HCl		
HF		
NMTOC/NMVOC	$0.00000 \times 10^{+0}$	$0.00 \times 10^{+0}$
CH_4	$1.03200 \times 10^{+1}$	8.09×10^{-6}
VOC/TOC total	$1.03200 \times 10^{+1}$	8.09×10^{-6}
CO_2	$6.07398 \times 10^{+4}$	4.76×10^{-2}
N_2O	$1.29000 \times 10^{+0}$	1.01×10^{-6}

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirtschaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

[a] PSEL-LCA Study, Chapter V.8.4, page 38. Indicates a worldwide range of 0.001 to 0.15% of transported gas. Other sources have 600 m^3/km - year equaling about 0.01% per 1000 km.

[b] PSEL-LCA Study, Chapter V.8.3, Table V.8.4, page 37. Indicates a worldwide range of 1.4 to 3.0% per 1000 km. For West Europe and Algeria 2.00%, CIS 3.0%.

Source: USEPA, Air Pollution Emission Factors, Vol. I, Stationary Point and Area Sources, AP-42, 5th edition, November 1996.

[d] USEPA AP-42 provides these values for gas compressors, all of them in g/GJ. The exception is the CO_2 emission factor, which was calculated on the basis of the percent of carbon content in natural gas, information that was provided by the Energy Ministry of Mexico.

Table 7.21 Energy parameters and emission factors for the coal production (step II)

CH4 emissions from gas production[a]	2.00	$m^3_{methane}/ton_{coal\ mined}$
Methane density[b]	0.67606	kg/m3
Emission factor CH4 (direct emissions)	135	g/ton_{coal}
Mining factor[c]	1.43	
Electricity requirements (indirect emissions)[d]	15.0	kWh/ton_{coal}
Diesel requirements (indirect emissions)[e]	8.9	l_{diesel}/ton_{coal}
Diesel heat content	45.4	MJ/kg
Diesel density[b]	1186.0	l_{diesel}/ton_{diesel}
Emission	**Large diesel engines[f]**	**Emission factor (indirect)**
	g/GJ	g/l_{diesel}
Particulates (total)	30.00	$1.15 \times 10^{+0}$
Particulates (PM-10)	24.70	9.46×10^{-1}
SO_X (as SO_2)	434.00	$1.66 \times 10^{+1}$
NO_X	1322.00	$5.06 \times 10^{+1}$
CO	349.00	$1.34 \times 10^{+1}$
HCl		
HF		
NMTOC/NMVOC	34.90	$1.34 \times 10^{+0}$
CH_4	3.10	1.19×10^{-1}
VOC/TOC total	38.00	$1.45 \times 10^{+0}$
CO_2	70950.00	$2.71 \times 10^{+3}$
N_2O		

[a] IPCC Guidelines Reference Manual 1996, page 1.108, equation 2. IPCC gives a range of 0.3 to 2.0. The upper value is used as a conservative estimate.

[b] USEPA Greenhouse Gas Inventory, Appendix Q, page 2.

Source: Ökoinventare von Energiesystemen, Project-und Studienfonds der Elektrizitätswirtschaft (PSEL-LCA), Budesamt für Energiewirtschaft (BEW), Juli 1996.

[c] PSEL-LCA Study, Chapter IV.6.4.2, Table VI.6.14, page 36. The values are: mining factor of 1.43 for surface bituminous, 1.67 for underground bituminous. Chapter VI.6.3.2, Table VI.6.7, page 27. the values are: mining factor of 3.7 m^3 of overburden per raw ton of coal.

[d] PSEL-LCA Study, Chapter IV.6.4.2, Table VI.6.14, page 36. The values are: Electricity of 15 kWh for surface bituminous, 85 kWh for underground bituminous. Chapter V.6.3.2, Table VI.6.7. page 27. the values are: for sub-bituminous 20 kWh per raw ton of coal.

[e] PSEL-LCA Study, Chapter IV.6.4.2, Table VI.6.14, page 36. The values are: Diesel of 340 MJ per ton usable coal for surface bituminous, 11 MJ per ton usable coal for underground bituminous. Chapter V.6.3.2. Table VI.6.7. page 27. the values are: for sub-bituminous 10 MJ

Source: USEPA, Air Pollution Emission Factors, Vol. I, Mobile Sources, AP-42, 5th edition, November 1996.

[f] USEPA AP-42 provides values for different mobile sources and fuels.

Table 7.22 Energy parameters and emission factors for coal transportation (step III)

Losses in transportation[a]	2.00	kg_{coal}/ton_{coal}
Coal losses	0.033	g_{coal}/ton_{coal} - km
Carbon content of auxiliary fuel (diesel)	86.01	%
Heat content of coal	16.20	MJ/kg
Density content of diesel[c]	1186.0	l_{diesel}/ton_{diesel}
Diesel requirements[b]	0.0056	l_{diesel}/ton_{coal} - km

Emission	**Diesel train**[d]	**Emission factor (indirect)**
	g/GJ	g/l_{diesel}
Particulates (total)	3.00	$3.00 \times 10^{+0}$
Particulates (PM-10)		
SO_X (as SO_2)	6.80	$6.80 \times 10^{+0}$
NO_X	44.00	$4.40 \times 10^{+1}$
CO	16.00	$1.60 \times 10^{+1}$
HCl		
HF		
NMTOC/NMVOC		
CH_4		
VOC/TOC total		
CO_2	2659.11	$2.66 \times 10^{+3}$
N_2O		

Source: [6].

[a] PSEL-LCA Study, Chapter VI.6.6.3, page 28. UBA estimates 0.2 kg/ton for handling and transport of brown coal (sub-bituminous). No information on bituminous.

[b] PSEL-LCA Study, Appendix B, page 32. Indicates 4.7 g_{diesel}/ton_{coal} - km.

[c] USEPA, Greenhouse Gas Inventory, Appendix Q, page 2.

Source: [7].

Air pollution can rise also from refuse pile fires, which can occur as the result of spontaneous combustion. Coal washing requires large amounts of water, the quantity depending upon the type of coal and the process used. The liquid effluent produced; commonly called "black-water", contain suspended small particles of coal and other solids. Black-water usually is sent to a "tailings pond" where the solids are allowed to settle and the clarified water is re-circulated to the washing process. Solid wastes from coal cleaning and processing consist of coarse and fine solids, that usually contain sulfur-bearing pyritic compounds and other chemicals, and that constitute a potential source of acid mine drainage.

According to the literature emissions from coal preparation are included in the mining process. Data sources typically give emissions for mining and preparation together and do not provide the information separately for each step. Therefore, emission factors associated with this step are included in Table 7.21.

7.2.23. Coal transportation (Level V)

Coal is transported by rail, road, waterways (rivers, canals, lakes, inter-coastal waterways and oceans), slurry pipelines and conveyor belts. Transport related environmental impacts occur during loading, conveyance and unloading of coal. The impacts affect natural systems, buildings and installations as well as humans.

Engines powering the transportation system cause noise and lead to pollutant emissions to the air. In addition, there are inevitably some accidents involving coal transportation vehicles (trains, trucks, barges, and ships) that can cause injury, death, damage to other facilities and environmental impacts. The transport of coal in all its forms involves unavoidable “fugitive dusts” (coal lost to the air in the form of small particles); even when preventive measures are taken. According to the general literature, for rail transport, it is estimated that about 25% of the total coal dust loss occur during loading, 50% during transit, and 25% during unloading. In addition to fugitive dust, there is some coal loss due to spillage.

Some estimates suggest that fugitive dust amount to about 0.2 kg/ton of coal loaded and a similar amount during unloading. Coal transport by rail has a number of other environmental impacts relating to noise (engine, exhaust, horn, wheel-rail interaction and brake cooling blowers). Diesel engines emit exhaust gases and some chemicals may be leached from the coal through exposure to rainfall during transit. Sparks from trains may cause brush fires, mainly along the rail right-of-way, but potentially spreading to surrounding areas. Control measures involve spraying vegetation along the right-of-way with chemicals.

Truck transport, usually confined to short distance haulage, involves exhaust emissions, coal spillage and fugitive dust losses (estimated at 0.04% of the load during loading and unloading combined and 0.05% during transit). Near the road noise from the trucks can exceed acceptable levels. Heavily laden coal trucks can cause structural damage to roads and bridges.

The transport of coal by water involves towed barges, motorized barges and ships. Losses during loading, unloading and transit are similar to those for truck and train transport. Finally, slurry pipelines with electrically powered pumping stations are used in some cases for transporting coal in water-based suspension. With this system, there are no fugitive dust losses and, with effective sound insulation and remote sitting, noise usually is not a problem. However, large quantities of water are needed for preparing the slurry and normally it is not economical to return the water for reuse. Thus, water consumption can have an adverse impact on the supplying water body (river or lake). Also, the slurry has to be “dewatered” prior to combustion in the power plant. The effluent from the dewatering process contains coal particles and saline compounds, and is a potential source of environmental impacts.

As in step III train transports coal’s transportation from the coal processing plant with diesel as auxiliary fuel. Table 7.23 shows the emission factor for step V in the coal chain.

Table 7.23 Energy parameters and emission factors for coal transportation (step III)

Losses in transportation[a]	2.00	kg_{coal}/ton_{coal}
Coal losses	0.167	g_{coal}/ton_{coal} - km
Carbon content of auxiliary fuel (diesel)	86.01	%
Heat content of coal	16.20	MJ/kg
Density content of diesel[c]	1186.0	l_{diesel}/ton_{diesel}
Diesel requirements[b]	0.0056	l_{diesel}/ton_{coal} - km

Emission	**Diesel train[d]**	**Emission factor (indirect)**
	g/GJ	g/l_{diesel}
Particulates (total)	3.00	$3.00 \times 10^{+0}$
Particulates (PM-10)		
SO_X (as SO_2)	6.80	$6.80 \times 10^{+0}$
NO_X	44.00	$4.40 \times 10^{+1}$
CO	16.00	$1.60 \times 10^{+1}$
HCl		
HF		
NMTOC/NMVOC		
CH_4		
VOC/TOC total		
CO_2	2659.11	$2.66 \times 10^{+3}$
N_2O		

Source: [6]

[a] PSEL-LCA Study, Chapter VI.6.6.3, page 28. UBA estimates 0.2 kg/ton for handling and transport of brown coal (sub-bituminous). No information on bituminous.

[b] PSEL-LCA Study, Appendix B, page 32. Indicates 4.7 g_{diesel}/ton_{coal} - km.

[c] USEPA, Greenhouse Gas Inventory, Appendix Q, page 2.

Source: [7].

7.2.24. Coal electricity generation (Level VI)

The qualities of coal in terms of heat output per tone or amounts of ash and other wastes vary considerably. For example, lignite has a lower heat value and contains significantly more ash than hard coal.

The type and efficiency of the installed flue gas treatment system will influence the amount of solid wastes also. For example, the use of limestone injected into the combustion chamber as a means for removing sulfur increases the emissions of CO_2 and the quantities of solid wastes in comparison with a plant equipped with a wet flue gas scrubbing system for sulfur control.

In addition, toxic components of the ash (metals, radio nuclides, etc.) are incorporated in the total solid waste volume from the plant using limestone injection, whereas in a plant equipped with wet scrubbers, the solid wastes from the post-combustion flue gas desulphurization process are, in essence, free of these components. This may affect the choice of systems for the management and disposal of the solid wastes. The storage of coal can present problems of spontaneous combustion, especially in the case of lower rank coals with high content of volatile compounds.

As in the case of the previous chains the emission factors for the electricity generation were discussed in detail in Chapter 3, therefore we refer to the reader to the expansion analysis chapter.

7.2.25. Nuclear chain

The nuclear energy chain is more complex than other energy chains. It has many levels and sub-levels. It can be divided into three main stages:

- The so-called front-end which extends from the mining of uranium ore until the delivery of fabricated fuel elements to the reactor site;
- Fuel use in the reactor, where fission energy is employed to produce electricity, and temporary storage at the reactor site; and,
- The so-called back-end, which starts with the shipping of spent fuel to away-from reactor storage or to a reprocessing plant ends with the final disposal of wastes from reprocessing or the encapsulates spent fuel itself.

The nuclear energy chain has been called for historical reasons “the nuclear fuel cycle”. Actually there are two options: the “open cycle” or “direct disposal” option, and the “closed cycle” or “reprocessing and recycling” option.

Some countries like USA and Sweden use the “open cycle” option, while most of the European countries (France, Germany, Belgium, Switzerland, Holland and Japan) use the “closed cycle”. Other countries like Spain, Korea, Taiwan and Mexico are still undecided with respect to this option that impacts mainly the backend of the nuclear chain.

Figure 5.3 shows the full nuclear energy chain defined in DECADES. The “Reprocessing” level and its preceding transport level should be omitted in the chain for the “open cycle”. The nuclear chain is very complex and requires a great number of steps with different technologies, with transportation steps indicated by the arrows; however its environmental impact is smaller than that generated in fossil fuel energy chains.

The DECADES chain assessment is designed to compute mass flows of fuels, wastes and emissions during the economic life of the energy chain and to calculate the levelized electricity generation costs. It is assumed that the energy chain is in equilibrium. One-time impacts like initial fuel loading and the decommissioning waste disposal are distributed over the electricity generated during the economic life of the chain.

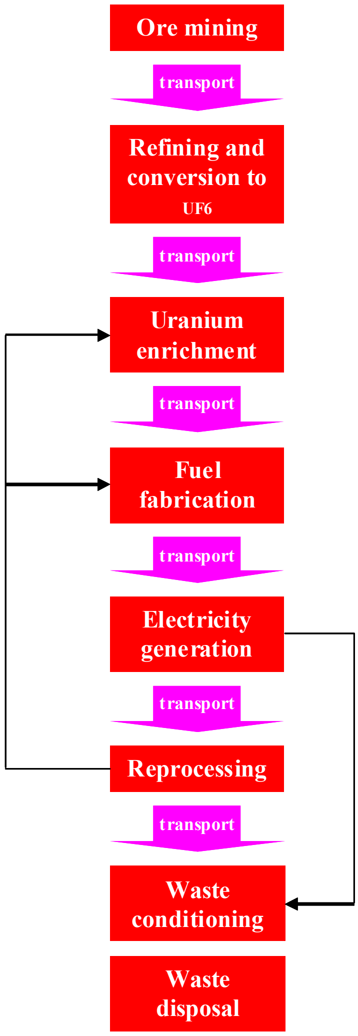

Figure 7.3 Nuclear chain.

At present there is only one nuclear power plant, with two BWR reactors, in Mexico at Laguna Verde in the State of Veracruz, 70 km north from the port of Veracruz. The fuel supplied to these reactors comes from the USA and other countries, so most of the impact in the front-end of the nuclear chain occurs outside Mexico. However the impact of the back-end will happen in Mexico.

Also, at present there is no policy about the spent fuel management of the Laguna Verde plant and both options of direct disposal and the closed cycle are still open, as in many other countries. Consequently, in the case of Mexico the nuclear chain only includes the transportation of fuel elements to the power plant, and the electricity generation step (Figure 7.4).

In Table 7.24 the main technical parameters for the Mexican nuclear chain in the database for DECADES can be observed. The N655 represents the Laguna Verde type reactor designed with a nominal capacity of 654 MWe that has been upgraded in power recently to 690 MWe. Two of this type of reactor is considered in the fixed system of the expansion. The N135 represents the candidate reactor for a large ABWR of a capacity of 1,314 MWe to be introduced in the variable system.

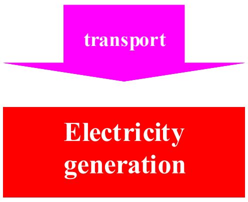

Figure 7.4 Mexican nuclear chain.

Table 7.24 Technical parameters

		N655	N135
Unit Technical Minimum	MW	551	1051
Output Capacity (Net)	MWe	656	1314
Output Capacity (Min)	MWe	551	1051
Equivalent Full Power	h/yr	7000	7258
Internal Consumption Fraction	%	3.1	3.1
Capacity Factor		0.799	0.828
Forced Outage	%	9.04	6.6
Maintenance Outage Rate	%	10.96	10.96
Scheduled Maintenance	days/yr	40	40
First Fuel Inventory	t	80.274	157.57
Enrichment-Equilibrium	% U235	3.92	4.49
Burn up	MWd/kg	45.2792	49
Net Efficiency (LHV)	%	34	34
Heat Rate - Full Load	kcal/kWh	2529	2570.2
Heat Rate - Average Incr.	kcal/kWh	2733	2570.2
Heat Rate - Min. Load	kcal/kWh	2733	2570.2
Plant Technical Lifetime	yr	40	40
Manpower Requirements	men/MWe	1.2	1.2
Cycle Length	mth	18	18

In Figure 7.5 the mass balance for the nuclear chains of the N655 and N135 reactors is presented. The mass balance shows the amounts of materials or services necessary in each step of the nuclear chain. For example for one reload of fuel of the Laguna Verde type reactor which will generate energy for 18 months, it will require 161,500 Kg U as uranium concentrates which will come from the mining of 64.6 million kg of uranium ore with an average content of 2.5 kg U/ton ore. After conversion of these concentrates to UF_6, with some material losses in the process, the amount will be used as feed in the enrichment plant.

At the enrichment plant, 114,350 kg of separative work units (SWU) will be required to increase the enrichment of uranium to 3.92% U-235. Each SWU is proportional to the energy that the plant will use in the isotopic separation process, plus other plant related charges. The SWU has a price calculated by the enrichment plant operator.

Finally the product of the enrichment plant, 20,220 kg U at 3.92% U-235, will be converted to UO_2 and this amount of fuel will be fabricated. All these steps of the nuclear chain will occur outside of Mexico.

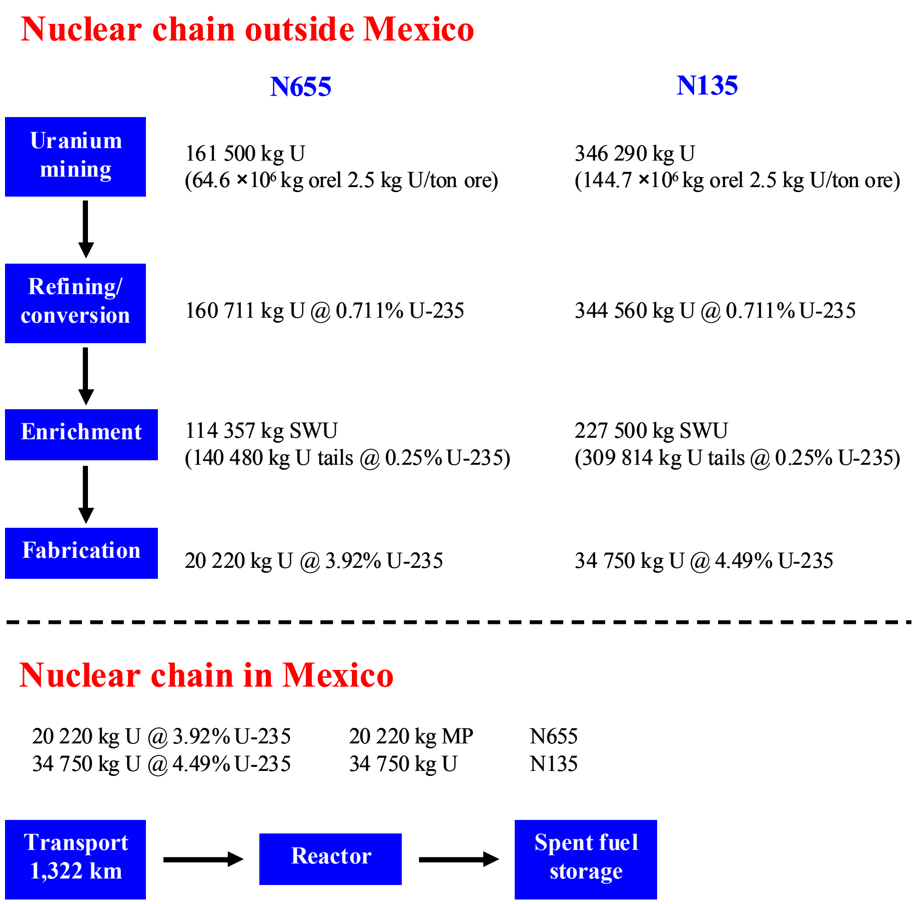

Figure 7.5 Balance mass for N655 and N135 nuclear chains.

The portion of the nuclear chain that occurs in Mexico is the transportation of the 20,220 kg U as fabricated fuel to the reactor plant, and its irradiation in the Laguna Verde reactors. The transportation of fuel elements is done by truck, which utilizes diesel as fuel. The distance in Mexican territory is 1,322 km and the combustion emissions produced in this step are also considered in calculations. The impact of the backend of the fuel cycle produced in Mexico will depend on the policy defined for the nuclear chain option. The reactor fuel and operation parameters necessary to define the nuclear chain cost, for the current operation conditions of the Laguna Verde plant, are presented in Appendix VI. There, the results of the calculation of the nuclear fuel chain cost using the methodology described by the IAEA in the benchmarking of extended burn up study[26] are presented.

7.2.26. Nuclear chain emissions

The nuclear fuel chain will produce solid, liquid and gaseous emissions. However this emissions are generally treated and contained, only emissions that are consistent with the natural background are discharged to the environment, and this is in accordance with the ALARA ("as low as reasonable acceptable") philosophy and in some cases the "zero discharge" philosophy is applicable.

This means that most of the environmental externalities produced in the nuclear chain are in fact internalized, in contrast with the externalities produced in other energy chains, like gas, oil or coal. As a matter of fact the nuclear chain is the lowest greenhouse gas producer and the nuclear reactor will produce zero greenhouse gases during its operation. All the nuclear wastes produced in the chain, either low/medium radioactive wastes (LMLW) or high-level waste (HLW) are conditioned and stored in safe conditions.

The different steps of the nuclear chain will produce some characteristic impacts such as the mining tails in the mining step or solid CaF_2 and fluorine gas in the conversion step. The enrichment step requires large quantities of water, electricity and also produces some enrichment tails. If the electricity necessary to operate these plants is produced by fossil fuels such as in the USA plants, we will have some secondary impacts in the form of air pollution coming from these plants.

All the rest of the nuclear chain steps such as fabrication or reprocessing plants, are relatively low impact with respect to the environment. Even the spent fuel storage facilities and radioactive waste repositories are safe in their design and produce a minimum impact to the environment.

The record of the transportation steps all over the nuclear chain is excellent and much better than the record of the transportation steps of the fossil chain. This is why we insist in saying that the nuclear chain has very small or almost zero externalities during normal operation, in comparison with other energy chains. If a fair comparison of technologies is to be made in the future, these large externalities of other energy chains must be evaluated and internalized in the chain.

We are not going to discuss all the impacts of the nuclear chain, because some of the impacts occur outside the boundaries of the study, in other countries. But we will discuss only the impacts of the nuclear chain in Mexico as seen in Figure 5.5. So these impacts will come mainly from the generation step of the plant, assuming that no other nuclear chain facilities will be built in the country during the term of the study. This is may not be completely true, because some spent fuel storage facilities or radioactive waste repositories may be built during the term of the study, but their specific time of construction has not been defined.

In Table 7.25, the emissions used for the nuclear chain in the study of environmental impact are shown. These emissions are typical values for BWR reactors.

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[26] "Water Reactor Fuel Extended Burn up Study", IAEA Technical Report Series No. 343, Vienna, 1992.

7.2.27. Renewable energy chains

Renewable energy sources are of two types: the first consists of more or less continuous natural energy flow, such as sunlight, wind, waves, etc. And the second consists of natural stocks of energy, which are renewed sufficiently rapidly for human use, such as biomass, hydropower reservoirs, etc.

These energy sources are quite heterogeneous and it is difficult to split them into cycle steps like in the case of the fossil fuels to identify the environmental residuals and impacts associated with each step of the specific chain. There is also considerably less literature on this subject compared with conventional energy sources.

Notwithstanding their generally favorable impression, renewable energy sources are not without potential environmental impacts. Because they are usually much more dilute forms of energy compared with fossil fuel or nuclear energy, renewable energy sources often require large structures for a comparable amount of energy produced, which means high material requirements and land use. It is also worth remembering that large-scale developments can also have climatologically or ecological impacts resulting directly from the diversion of a natural energy flow or the intensive use of a natural energy stock. On the positive side must be considered the avoidance of adverse environmental effects associated with the types of electricity generation displaced.

Hydropower is the main contributor of the renewable energy sources to electricity generation. Substantial research and development efforts are being made aiming towards enhancing the technical and economic performance of solar, wind, biomass and other renewable energy technologies. Already, some of these technologies are economically viable in favorable locations (e. g., wind power in locations with steady strong winds, solar power in remote locations not connected to electricity distribution networks). However, it is not expected that renewable energies will provide an important amount of the world's electricity in the next few decades. Renewable energy sources for electricity generation have to meet some criteria in order to be considered, in an appropriated magnitude, as a reliable energy source. Such criteria are: the energy source should have an adequate resource base and that can be produced in quantities suitable for power generation purposes. For renewable energy sources such as solar, wind and geothermal, this implies that the natural energy can be collected in adequate quantities and converted to electricity with a practical efficiency. Also, electricity generation utilizing the energy source must be economically competitive with alternative options and, safety risks and social and environmental impacts must be acceptable and should not be higher than with competing fuels.

With regard to electricity generation system expansion, special consideration has to be given to the stochastic availability of renewable energies; that is, the intensity of wind and sunshine varies with the time of the day and the season of the year, and these variations cannot be forecasted with certainty. Therefore, the introduction of a large share of generation based on renewable energies can lead to a higher uncertainty on the reliability of supply being available when it is needed.

The following sections will examine the environmental residuals and impacts more specifically associated with the most common forms, in the Mexican generation system, of renewable energy; geothermal, hydroelectric and wind energies. It should be noted that of these, solar and wind can be used in small-scale applications as well as to generate electricity at a centralized facility. Their environmental implications for smaller uses are not only different in scale, but may differ in nature as well.

Table 7.25 Environmental emissions for nuclear chain

		N655	N135
Air			
Cr-51	MBq/GWyr	1.08	1.08
Kr-85m	MBq/GWyr	123000	123000
Kr-87	MBq/GWyr	94700	94700
Kr-88	MBq/GWyr	105000	105000
Kr-89	MBq/GWyr	505000	505000
Xe-131m	MBq/GWyr	2180000	2180000
Xe-135	MBq/GWyr	$3.03 \times 10^{+8}$	$3.03 \times 10^{+8}$
Xe-135m	MBq/GWyr	2750000	2750000
Xe-137	MBq/GWyr	302000	302000
Xe-138	MBq/GWyr	759000	759000
Mn-54	MBq/GWyr	0.0959	0.0959
Co-58	MBq/GWyr	5.37	0.0424
Co-60	MBq/GWyr	82	4.47
Zn-65	MBq/GWyr	4.03	4.03
Sr-89	MBq/GWyr	0.587	0.587
Sr-90	MBq/GWyr	0.0539	0.0539
Nb-95	MBq/GWyr	0.0285	0.0285
Ru-103	MBq/GWyr	0.00883	0.00883
Sb-125	MBq/GWyr	0.391	0.391
Cs-134	MBq/GWyr	0.27	0.27
Cs-137	MBq/GWyr	6.06	6.06
Ba-140	MBq/GWyr	237	237
La-140	MBq/GWyr	1	1
Ce-141	MBq/GWyr	0.00921	0.00921
Kr-85	MBq/GWyr	319000	319000
Xe-133	MBq/GWyr	843000	3390000
I-131	MBq/GWyr	30.8	884
I-133	MBq/GWyr		
C-14	MBq/GWyr	591000	591000
Ar-41	MBq/GWyr	36000	36000
Water			
Co-58	MBq/GWyr	5320	5320
Co-60	MBq/GWyr	27100	27100
H-3	MBq/GWyr	1250000	839000
Cs-134	MBq/GWyr	24.3	380
Cs-137	MBq/GWyr	65.9	2910
Mn-54	MBq/GWyr		149
Mn-58	MBq/GWyr		1.28

7.2.28. Hydroelectric chain

Hydroelectric power plants contribute to the emissions due to the dam construction activities and those from decomposition of submerged biomass in hydroelectric reservoirs. When creating hydroelectric reservoirs, land surfaces containing phytomass (i. e. trees, grass, general vegetation, etc.) are flooded. The submerged phytomass undergoes anaerobic decomposition into greenhouse gasses such as CO_2 and CH_4, with the rate of decomposition depending on the types of phytomass and the physical and chemical properties of the water. The main conditions influencing decay rate and types of emissions are water temperature, water quality, acidity, dissolved oxygen, oxidation potential, light intensity, pressure and reservoir morphometry.

The hydro chain contains only two steps: water reservoir and hydro power plant. The specification of the chain requires installed capacity, energy storage, equivalent full power hours of operation per year, net overnight cost (NOC), NOC domestic fraction, fixed operation and maintenance costs, economic lifetime, construction period, interest during construction, CH_4 emission factors from the reservoir, material requirements, etc. The emission factors for a given pollutant in the hydro chain are originated en two sources: the reservoir and the materials used. The carbon cycle in the water reservoir from which CO_2 and CH_4 are released, is part of a complex ecological system with interconnected chemical, physical and biotic factors (Figure 7.6).

This system being a complex one increases its complexity due to the variety of water reservoirs. In terms of the conditions for Greenhouse Gasses release one should distinguish between cold climate, humid tropical and alpine areas.

Many factors can influence emissions of Greenhouse Gasses from hydropower reservoirs (Figure 7.6), among such factors are emissions of CO_2 and CH_4 from biodegradation of flooded biomass on the floor of the water reservoir; natural aquatic biomass build-up and biodegradation; removal of the original vegetation which was a CO_2 sink; and in view of the importance of CH_4 emissions from hydropower reservoirs, special attention will be given to its global warming potential.

According to the traditional DECADES methodology, there are two types of hydropower plants: reservoir power plants and run-of-river power plants. The run-of-river power plants constitute a separate category with probably low upstream Greenhouse Gasses emissions, because of the small actual reservoir size. The run-of-river is connected to an upstream reservoir that has little useful storage volume and turbine the water as it becomes available. The water not utilized is spilled over.

On the other hand, storage power plants are connected to an upstream reservoir that has significant useful storage volume. The can store the water for periods with low power requirements and utilize it when the power demand is high. This regulation capability may be daily, weekly, seasonal or inter-annual, depending on the size of the reservoir and the pattern of water inflows.

In some sense is easy to make an inventory of the different kinds of environmental impact; on the other hand it is difficult to use quantitative measures. The environmental impact of hydropower is in many respects more direct than that of fossil fuel-fired power plant and is easy to connect a certain environmental effect to a particular hydropower site, but is considerably more difficult when it comes to the effects. The environmental effects that are typical in the case of hydropower, for instance the impact on the landscape and biodiversity, cannot be quantified in the same manner as, for example, acidification caused by sulfur emissions.

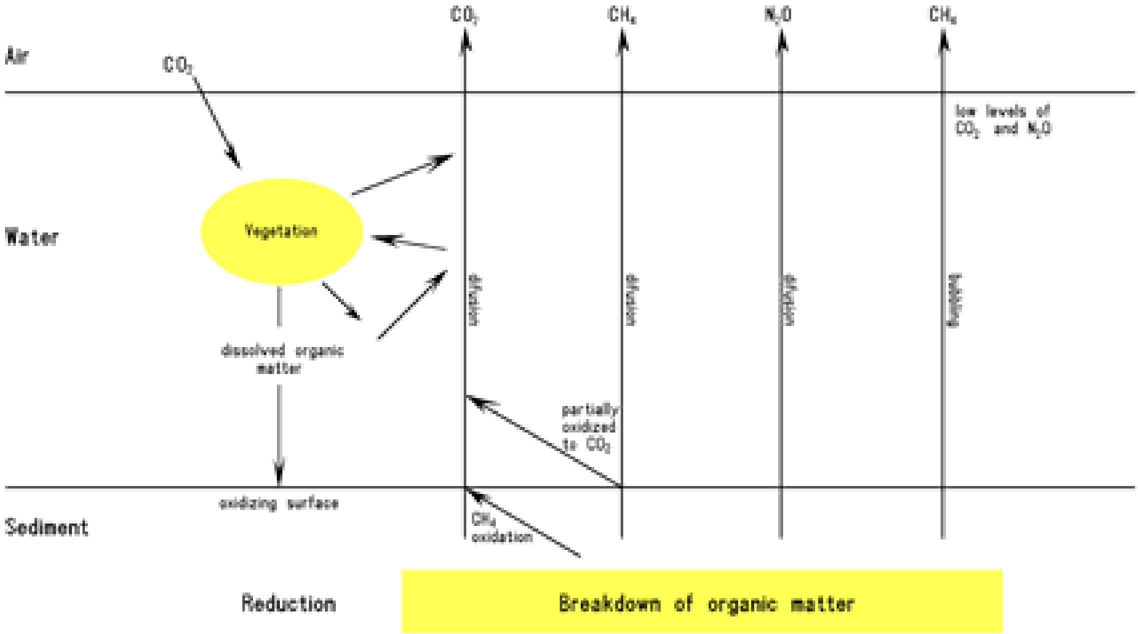

Figure 7.6 Schematic representation of the various processes that determine the release of greenhouse gases from water reservoirs of hydropower plants.

In Mexico, hydropower generation is carried out mainly in south part of the country (in 1998 the Grijalva region produced 10,451.8 GW·h, 42.68% of the total hydroelectric generation), the Balsas-Santiago region (5,967.8 GW·h, 24.37%), the Gulf region (2,521.6 GW·h, 10.30%); the Ixtapantongo region (2,518.3 GW·h, 10.28%), the north-west region (1,909.1 GW·h, 7.80%), and the Central region (892.4 GW·h, 3.64%), the north-east region (124.1 GW·h, 0.51%) and the north-center region (101.1 GW·h, 0.41%).

The Grijalva and Balsas-Santiago regions are located in a humid tropical area, the Gulf and Ixtapantongo regions in the central part of the country. These four regions account for the 87.64% of the total hydroelectric generation, while the Grijalva and Balsas-Santiago regions account for the 67.05%. Most of the hydropower facilities are of the dam type and few are run-of-river.

According to Figure 7.6 the releases of greenhouse gases from water reservoirs of hydropower plants are very complex, the variety of water reservoirs adds complexity to this energy chain, even that the energy chain is only a two-step chain. On the other hand DECADES methodology distinguishes between cold climate and humid tropical areas. Also, according to the previous paragraph more than 67% of the total generation is located in humid areas; therefore the main assumption for this energy chain was to consider the whole system as located in humid areas. On the basis of this assumption, the emission factor for CO_2 and CH_4 were 4.973 g/me/day for the CO_2 and 0.112 g/me/day for the CH_4. The details of existing hydropower plants as well as their parameters are discussed in Chapter 3, as well as in the Appendixes.

7.2.29. Geothermal chain

The use of geothermal energy is based thermodynamically on the temperature difference between a mass of subsurface rock and water and a mass of water or air at the earth's surface. This temperature difference allows production of thermal energy that can be either used directly or converted to mechanical or electrical energy.

Temperatures in the earth in general increase with increasing depth, to 200 –1 000 ºC at the base of the Earth's crust and to perhaps 3 500 – 4 500 ºC at the center of the earth. The heat produces geothermal gradients and this heat comes from two sources: flow of heat from the deep crust and mantle; and thermal energy generated in the upper crust by radioactive decay of isotopes of uranium, thorium, and potassium. Some granite rocks in the upper crust, however, has abnormally high contents of uranium and Thorium and thus produce anomalously great amounts of thermal energy and enhanced flow of heat toward the earth surface. Consequently, thermal gradients at shallow levels above these granite plutons can be somehow higher.

These thermal gradients can be calculated under the assumption that heat moves toward the earth surface only by thermal conduction through the solid rock. However, thermal energy is also transmitted toward the earth surface by movement of the molten rock (magma) and by circulation of water through interconnected pores and fractures. These processes are superimposed and give rise to very high temperatures near the earth surface. Areas characterized by such high temperatures are the primary targets for geothermal exploration and development.

Commercial exploration and development of geothermal energy have focused on natural geothermal reservoirs - volumes of rock at high temperature and with both high porosity (pore space, usually filled with water) and high permeability (ability to transmit fluid). The thermal energy is tapped by drilling well into the reservoirs. The thermal energy in the rock is transferred by conduction to the fluid, which subsequently flows to the well and then to the earth surface.

Natural geothermal reservoirs, however, make up only a small fraction of the upper part of the earth crust. The remainder is rock of relatively low permeability whose thermal energy cannot be produced without fracturing the rock artificially by means of explosives or hydro fracturing. There are several types of natural geothermal reservoirs. Most of the reservoirs developed to date for electrical energy are termed hydrothermal convection systems and are characterized by circulation of meteoric (surface) water to depth. The driving force of the convection systems is gravity, effective because of the density difference between cold, downward moving, recharge water and heated, upward-moving, thermal water.

A hydrothermal convection system can be driven either by an underlying young igneous intrusion or by merely deep circulation of water along faults and fractures. Depending on the physical state of the pore fluid, there are two kinds of hydrothermal convection systems: liquid -dominated, in which all the pores and fractures are filled with liquid water that exists at temperatures well above boiling at atmospheric pressure, owing to the pressure of overlying water; and vapor-dominated, in which the larger pores and fractures are filled with steam. Liquid-dominated reservoirs produce either water or a mixture of water and steam, whereas vapor -dominated reservoirs produce only steam, in most cases superheated.

In some rapidly subsiding young sedimentary basins such as the northern Gulf of Mexico Basin, porous reservoir sandstones are compartmentalized by growth faults into individual reservoirs that can have fluid pressures exceeding that of a column of water and approaching that of the overlying rock. The pore water is prevented from escaping by the impermeable shale that surrounds the compartmented sandstone. The energy of these geopressured reservoirs consists not only of thermal energy, but also of an equal amount of energy from methane dissolved in the waters plus a small amount of mechanical energy due to the high fluid pressures.

Although geothermal energy is present everywhere beneath the earth's surface, its use is possible when certain conditions are met:

- The energy must be accessible to drilling, usually at depths of 3 000 meters (6 to 7 km under particularly favorable environments, such as is the case of the northern Gulf of Mexico Basin);

- Pending demonstration of the technology and economics for fracturing and producing energy from rock of low permeability, the reservoir porosity and permeability must be sufficiently high to allow production of large quantities of thermal water;

- Since the major cost in geothermal development is drilling and since cost per meter increase with increasing depth, the shallower the concentration of geothermal energy the better; and

- Geothermal fluids can be transported economically by pipeline on the earth's surface only a few tens of kilometers, and thus any generating or direct-use facility must be located at or near the geothermal anomaly.

The most conspicuous use of geothermal energy is the generation of electricity. Hot water from the liquid-dominated reservoir is flashed partly to steam in the earth's surface, and this steam is used to drive a conventional turbine-generator set. In the relatively rare vapor-dominated reservoirs, superheated steam produced by wells can be piped directly to the turbine without need for separation of water. Electricity is most readily produced from reservoirs of 180ºC or greater, but reservoirs of 150ºC or even lower show promise for electrical generation, either by using steam directly or by transferring its heat to a working fluid of low boiling point such as isobutene or freon. Besides electric generation, there are direct uses such as heating and cooling of buildings, to provide hot or warm water for domestic use, for product processing, and many other possible uses.

In any analysis of the possible contribution of geothermal energy to human energy needs, one must keep in mind that the geothermal resource is only a fraction of the thermal energy in the subsurface volume of rock and water. For favorable hydrothermal convection systems, this fraction can be 25% or greater, but for systems of restricted permeability the fraction is likely to be far smaller. Only this recoverable energy can be meaningfully compared with the thermal energy equivalent of barrels of recoverable oil, cubic meters of recoverable gas, tons of minable coal, or kilograms of minable uranium.

The main environmental problems in producing geothermal power involve mineral deposition, changes in hydrological conditions, and corrosion of equipment. Pollution problems arise in handling geothermal effluents both water and steam. Geothermal energy may have adverse environmental effects on air, water, and land. The exact effects are site-specific varying according to the properties of the reservoir and the plant design.

Air pollutants are emitted through direct releases of geothermal steam and through releases of non-condensable gases. The type and quantity of pollutants are site-specific and they will depend on the chemical composition of the geothermal fluid. In some water-dominated fields there may be mineral deposition from boiling geothermal fluid. Silica deposition in wells can cause problems. Calcium carbonate scale formation in wells or in the country rock may limit field development.

Extensive production from wells changes the local hydrological conditions. Decreasing aquifer pressures may cause boiling of the water in the rocks (leading to changes in well fluid characteristics), encroachment of cool water from the outskirts of the field, or changes in water chemistry through lowered temperatures and gas concentrations. After an extensive withdrawal of hot water from the rocks of low strength, localized ground subsidence may occur and the original natural thermal activity may diminish in intensity. Land subsidence appears to be a problem, but mainly in liquid-dominated geothermal fields.

In the case of vapor-dominated geothermal fields, subsidence does not appear to be problem, because the formation of these fields requires the presence of a rock that is not subject to compaction and subsidence. Anyway, some changes occur in all fields, and a good understanding of the geology and hydrology of a system is needed so that the well withdrawal rate can be matched to the well's long term capacity to supply fluid.

Geothermal waters cause an accelerated corrosion of most metal alloys, but this is not a serious utilization problem except in areas where wells tap high-temperature acid waters. The usual deep geothermal water is of near neutral pH. The principal metal corrosion effects to be avoided are sulfide and chloride stress corrosion of certain stainless and high-strength steels and the rapid corrosion of cooper-based alloys. Hydrogen sulfide, or its oxidation products, also causes a more rapid degradation than normal of building materials, such as concrete, plastics and paints.

Geothermal steam suppliers differ widely in gas content. The gas is predominantly carbon dioxide, hydrogen sulfide, methane, and ammonia. Hydrogen sulfide (H_2S) is the air effluent of the biggest concern as it is highly toxic. Its direct effect on humans ranges from noxious odor at lower concentrations through systemic symptoms and death at higher concentrations and relatively short exposure time. In the case of geothermal energy, H_2S concentrations are usually below toxic levels, but H_2S is a problem because its odor and chemical reactivity. Implications of this may include corrosion of metals, blackening of paints, and vegetation damage. It therefore may then require control in specific cases.

CO_2 effluents do not create environmental problems near the plant, but may make a contribution to global atmospheric build-up of CO_2. Some estimates indicate that the contribution can be of a similar magnitude to that from a coal-fired plant. According to the UNEP[27], in the case of Cerro Prieto's power plant the amount of CO_2 could be of 150 000 ton per year on the basis of a 100 MW plant.

Ammonia (NH_3) creates no problem by itself because atmospheric processes to acceptable levels rapidly diffuse it. However, if NH_3 reacts with other chemicals, it can cause harmful environmental impacts; for example, ammonia may react with H_2S to form ammonium sulphate, which is harmful to the environment. Site-specific conditions may require some form of control.

Radon-222 is found in trace-amounts in the non-condensable gas portion of geothermal steam. However, radon has not been found to be a problem at geothermal plants. Nevertheless, it is necessary to study its effects when dispersed. Same situation appears to be in the case of mercury in geothermal steam, which is finally released into the atmosphere, but the concentrations created have to be studied.

[27] UNEP, The Environmental Impacts of Production and Use of Energy, Part III: Renewable Sources of Energy, Nairobi, August 1980.

The compositions of geothermal waters vary widely. Those in recent volcanic areas are commonly dilute saline solutions, but waters in sedimentary basins or active volcanic areas range upward to concentrated brines. Most geothermal hot waters contain a relatively large amount of dissolved solids and heavy metals. Usually, geothermal water is sodium, potassium chloride solution containing relatively large concentrations of some elements and metals. In comparison with surface waters, most geothermal waters contain exceptional concentrations of boron, fluoride, ammonia, silica, hydrogen sulfide, and arsenic. In the common dilute geothermal waters, the concentrations of heavy metals such as iron, manganese, lead, zinc, cadmium, and thallium seldom exceed the levels permissible in drinking waters. However, the concentrated brines may contain appreciable levels of heavy metals.

Because of their composition, effluent geothermal waters or condensates may adversely affect potable or irrigation water supplies and aquatic life. Ammonia can increase weed growth in waterways and promote eutrophication, while the entry of boron to irrigation waters may affect sensitive plants such as citrus. Small quantities of metal sulfide precipitate from waters, containing arsenic, antimony, and mercury, can accumulate in stream sediments and cause fish to derive undesirably high mercury concentrations.

The following methods could be used for disposing the waste of waste water: direct release to surface water bodies, evaporation, surface spreading to shallow aquifers, desalination with subsequent water reuse, and re-injection to the reservoir. The exact disposal method depends on local hydrologic conditions, water requirements, and environmental regulations. In the case of re-injection, steam condensate re-injection seem to have few problems, but the case of much larger volumes of separate waste hot water from water-dominated fields present a more difficult re-injection situation.

Silica and carbonate deposition may cause blockages in the rock fissures if appropriate temperature, chemical, and hydrological regimes are not met at the disposal depth. In some cases, chemical processing of the brines may be necessary before re-injection. Selective re-injection of water into the thermal system may help to retain aquifer pressures and to extract further heat from the rock. Dissolved silica may create problems, because if it enters the wastewater channels, the latter have to clean regularly.

For example, the water from Cerro Prieto's power plant contains, approximately, the same quantity of silica than Los Azufres power plant, six times more chloride, potassium and sodium. On the other hand Los Azufres presents more than 200 *ppm* of boron and 20 *ppm* of arsenic.

These considerations induce to recognize that the water deposition method will be different from one place to another. In Cerro Prieto's power plant is possible to dispose of the wastewater in evaporation ponds since the power plant is located at a desert area. This is not the case of Los Azufres since the climate and orography would prevent this possibility.

Noise could be another problem with geothermal energy, since noise levels could reach 120 decibels in the vicinity of unsilenced geothermal wells. Silencers could reduce the noise level to below 100 decibels and remove the high frequencies. Uncontrolled wells may produce ground vibrations and secondary drilling may be required to stop these vibrations.

Finally, the amount of land required for the development of a geothermal field depends on the topography and the well density. In geothermal plants with a low efficiency the waste heat discharge may create problems, such as local fog formation and icing of roads during winter.

According to the results presented in Chapter 4, expansion analysis does consider geothermal power plants; on the other hand DECADES methodology considers this type of generation facilities; however it does not include them in the calculation. Nevertheless, Table 7.26 shows the emission factors for the existing plants.

Table 7.26 Emission factors for geothermal power plants

Emission	G020	G050
	g/kWh	g/kWh
CO	0.0	0.0
CO_2	172.8	186.6
NH_3	0.39	0.4
N_2S	2.4	2.1
NO_X	0.98	2.65
SO_X	5.39	10.16

7.2.30. Wind chain

Wind generators have been used in a decentralized way for centuries, first to provide motive power and more recently electricity on a small scale. Over the past few decades' attention has been dedicated to the possibility of larger scale electricity generation on "wind farms" situated in favorable areas.

The environmental impacts of wind energy are in general of small magnitude and could be classified into visual pollution, noise, telecommunication interference, safety and breakdown hazards. As windmills have to be located on exposed sites, they are usually visible from afar. The pylons and the rudder mainly cause visual pollution, since the blades are invisible when they are rotating. The use of colors for the pylons and rudder can significantly reduce visual pollution. The visual impact is somewhat subjective, for example, traditional windmills in Holland are not considered to be visually offensive. Even that visual impact of wind turbines is of a rather qualitative nature, it can be a realistic planning restriction, particularly for areas of outstanding natural beauty, landscapes with cultural value and in densely populated areas or countries. The disturbance caused by the noise produced by wind turbines, is probably the most important drawback to sitting wind turbines close to inhabited areas. The acoustic emission is composed of a mechanical and aerodynamic part. The aerodynamic part in the acoustical emission is a function of the wind speed. According to the literature, for turbines with rotor diameters up to 20 meters the mechanical component dominates, whereas for larger rotor diameters the aerodynamic component is predominant. The noise problem emerges especially in densely populated areas and can cause limitations to potential wind turbine areas.

Wind turbines present an obstacle for incident electromagnetic waves. These waves can be reflected, scattered and diffracted. This means that wind turbines may interfere with telecommunication links. Therefore, this can be another problem for the spreading of this technology since wind turbines should not interfere with telecommunication links, or with domestic radio and television reception.

Accidents with wind turbines are rare but they do happen, as in other industrial activities. Breakdown hazards can occur even a blade comes off its supporting structure or the entire windmill is toppled because of wind speeds exceeding design. Therefore, it is necessary to develop safety standards for wind turbines addressing safety philosophy, structural integrity and personnel safety. Perhaps, the aim of the document will have to be on guidance to the designers so that the probability of an accident with the wind turbines they produce is at an acceptable level.

The operation of wind turbines may damage birds. This damage can be split up into bird kills as a result of collisions with tower or blades and the disturbance of breeding or resting birds in the vicinity of turbines. It seems that this problem is small, although it is clear that possible damage to bird life must be analyzed, in detail and very carefully, and might limit the application of wind energy in certain regions, such as migratory flyways. Finally, the construction and operation of wind turbines cause some pollution. However, little is known about these so-called indirect emissions. According to general literature CO_2 emissions can be produced during construction (around 7 ton per GW·h) but in total the CO_2 emission over the total operating period is very low.

At the present, the Mexican electric system counts with a wind capacity of 2 MW but no information about emission factors during operation. According to the DECADES methodology this chain will be a one step chain, that is, only the electricity generation step, of course there are contribution from materials and, perhaps, some indirect fuels.

7.2.31. Elementary comparison of three expansion technologies

As an example of the DECADE's chain analysis and full chain emission analysis Figure 7.7 shows the case of three of the four technology options in the expansion analysis of the Mexican electrical system. The expansion technologies shown in Figure 7.7 are natural gas combined cycle (CC546 (1 × 350 MW) as CC54 in the figure), Dual coal based with desulphurization (D350 (2 × 350 MW) as ND35 in the figure) and natural gas simple cycle (T179 (1 × 179)). The fourth technology was an advanced boiling water reactor (N135, 1 × 1,356 MW).

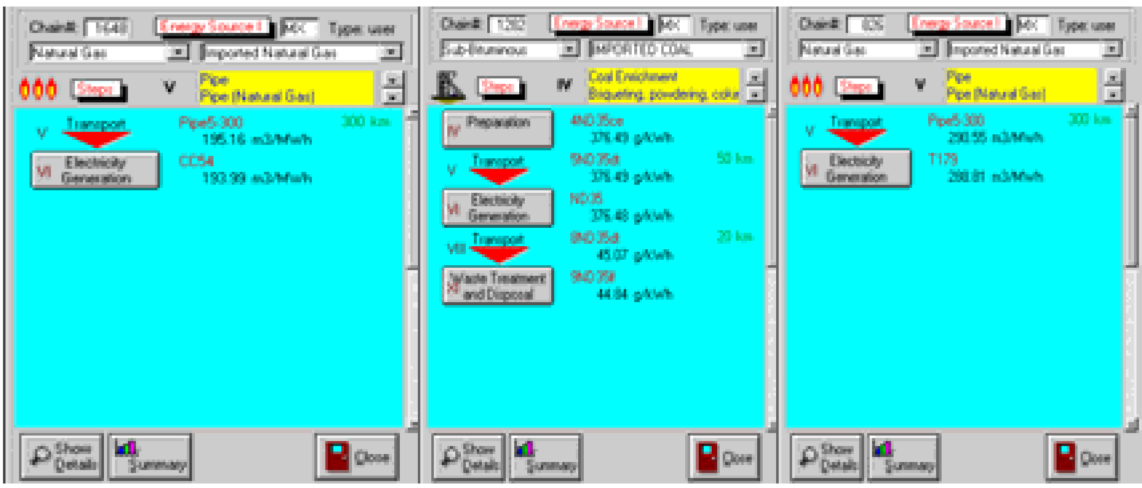

Figure 7.7 Side-by-side displays of energy chains.

From the figure is clear that of the three options two are based on imported natural gas and the third one on imported coal. Also is clear the difference in steps in each of the chains. In the coal case it is, also, clear the type of preparation process. For the other two chains the preparation step is not necessary since it is assumed that the preparation was done in the facilities of the exporting country. For each step in the chain appears an identification of the type of process or transport used, a mass balance for each step and the average distance of transportation, also it is shown the data for the generation plant.

Another chain analysis comparison that can be done is presented in Figure 7.8. There we can see the contribution to emissions of the three expansion options and two steps (V and VI) in the chain. All the graphs show that the step VI is the major contributor to the emissions of the whole chain and therefore under an environmental policy of reduction of emissions this sector will be the main target for emission reductions.

Looking at the CO_2 graph, we can see that the transport step contributes very slightly in all the chains. The important contributor is step VI and, within this step the coal plants come in first place as source of emissions, followed, in second place, by the natural gas simple cycle (with 21.92% less emissions than the coal's option) and, finally the combined cycle (with 47.55% less emissions than the coal's option).

In the case of NO_X emissions (Figure 7.9) coal’s option is in first place in terms of contributions, natural gas simple cycle is second (74.38% less than the coal's option) and natural gas combined cycle third (82.78% less than the coal's option).

In terms of SO_X emissions (Figure 7.8), again the coal’s option is the important one with, almost, no emission from the other options. Looking at the CH_4 emissions (Figure 7.9), the most important contribution comes from the natural gas simple cycle option, followed by the coal option with very small contribution from the combined cycle option. Finally, for the particulate emissions (Figure 6.10) coal’s option is the only contributor.

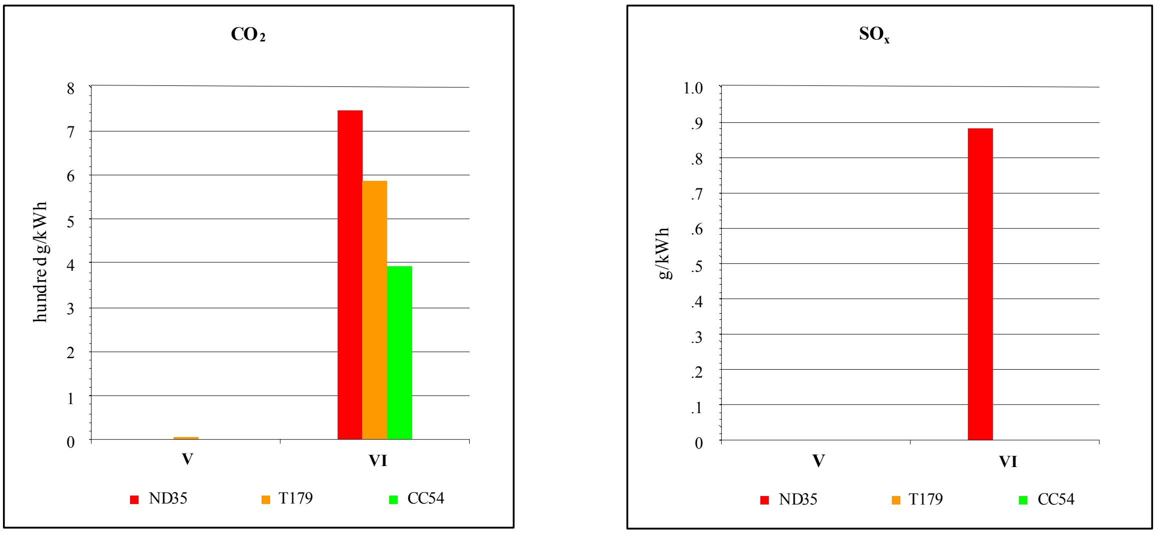

Figure76.8 CO_2 and SO_X chain emission comparison for Nd35, T179 and CC54 expansion options.

Therefore, at first sight, if Greenhouse Gases is the important issue for a sustainable development of the electrical sector in Mexico, the coal option would not be a convenient one and for the rest of the fossil fuel choices the most recommendable would the combined cycle.

Of curse, nuclear option does not have any Greenhouse Gases emissions and will have to be considered as a possible option under Greenhouse Gases point of view. However, all options will have to be analyzed under economical, safety, technological and reliability conditions.

7.3. Decision-making analysis of power system expansion

7.3.1. Applied methodology of decision-making analysis

After the system level analysis of the generation system expansion scenarios is concluded, and a number of interesting expansion scenarios is selected, it is necessary to implement a decision analysis methodology in order to determine the optimal solutions for the system. The final step of an energy study is to provide relevant information about these competing options to decision makers in a way that will facilitate their decisions.

In general terms the problem of decision-making is composed of three elements: 1) an *objective* or goal, 2) a number of *criteria* to evaluate this objective and 3) a number of *alternatives* to select. For example, in an electric system expansion scenario the objective may be minimum cost and there may be several different alternatives, each based on different assumptions: no constraints, a limit to gas availability, a different discount rate, etc. Examples of other objectives are to create jobs, to reduce pollution, to reduce dependence on imports, etc.

In such a problem it is necessary to have measures or indicators that would show how good or bad are the alternatives in achieving these objectives. Such measures are called criteria and the problems are called multiple criteria decision analysis problems. The number of objectives and the number of criteria may not and often do not coincide. For example, several criteria may be required to measure the level of air pollution: emission levels of CO_2, SO_2, methane, particles, etc.

Each criterion has its units of measurement and its direction. The direction indicates whether the criterion is to be maximized or minimized. For example the SO_2 emissions from a selected scenario can be computed and measured in tons of SO_2 and it is desirable to minimize them. The difficulty of choosing the best alternative in this type of problems is that normally there is no single alternative, which is the best for all criteria. For example the most ecologically friendly decision alternative may be one of the most costly. On the other hand, the least expensive option may be unacceptable because of the pollution it would cause.

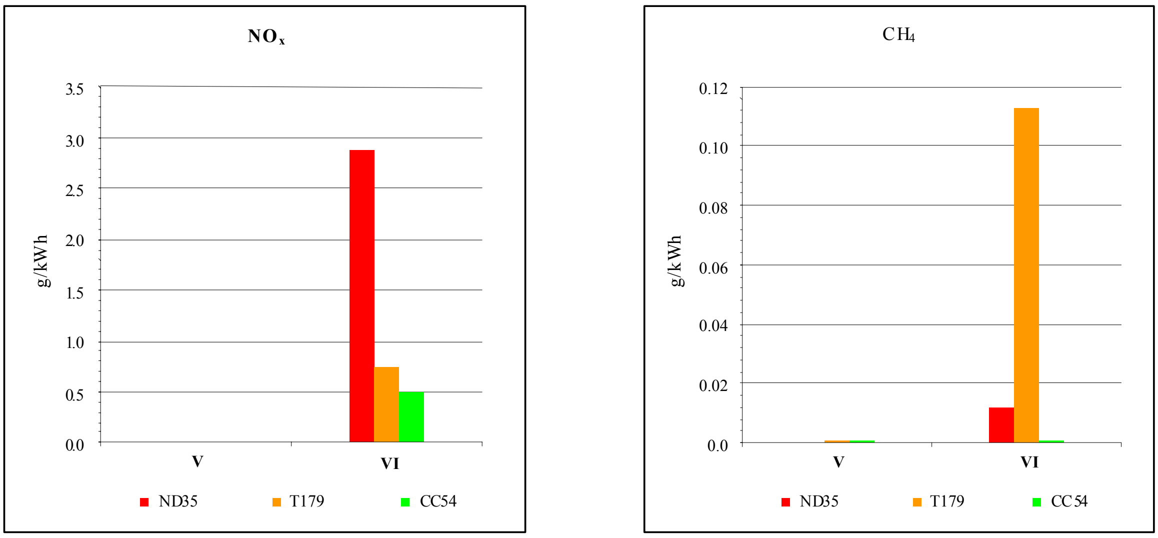

Figure 7.9 NO_X and CH_4 chain emissions comparison for ND35, T179 and CC54 expansion options.

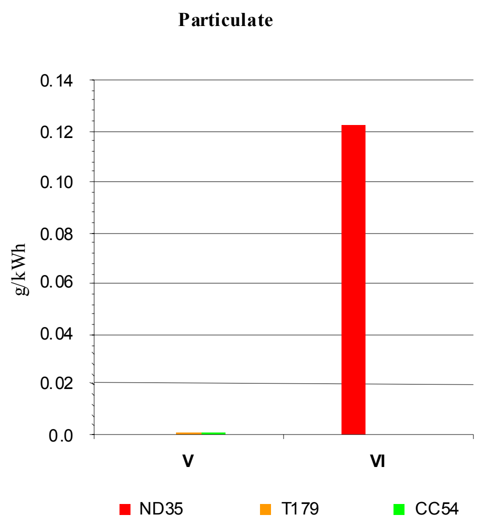

Figure 7.10 Particulate chain emissions comparison for ND35, T179 and CC54 expansion options.

Several approaches have been designed to cope with these types of problems: the interval decision methodology is one of them. In this methodology you have first to reduce all your criteria to one, for example cost. The way to do this is by using weights (e.g. unit costs of pollution) or trade-offs, if we have relevant information between the environmental impacts of several types of pollutants and can translate this information into only one type. For example we can say that the environmental impact of 1 ton of SO_2 is equivalent to that of 5 tons of CO_2.

The problem with using this methodology is that we don't know accurately the cost or trade-off of a given environmental impact. Recently there have been serious studies on the evaluation of these costs by means of "externalities" [28], but there is still a great variability and uncertainty on these costs at a local, regional or global level.

This uncertainty can be always being reduced by means of gathering more information, consulting with experts or getting different perspectives from opinion groups. Generally we will end up not with one value, but with a range of values; and the greater the uncertainty, the larger the range or interval.

Another point to consider is that as time will pass these "external" costs will be internalized in the cost of each alternative by means of more restrictive environmental regulations or international agreements, like those of the Kyoto protocol, to reduce greenhouse emissions. An effort should be made to find truly "sustainable" options in the long range, in comparison with the narrow view, "short term" analysis.

To compare different scenarios of electricity generation is a complex problem with multiple conflicting objectives, therefore an effort should be made to improve the way in which information is displayed, aggregated and evaluated.

[28] ExternE Externalities of Energy – National Implementation (1998), CIEMAT (ed.)

For this purpose DECADES has developed a modular approach by means of the DECADES tool DAM – the Decision Analysis Module -[29]. This module is based on the "interval decision methodology". DAM is a computer program developed to aid a decision analyst in solving multiple criteria decision analysis problems. DAM will allow the decision analyst to:

- Identify candidate solutions (optimal alternatives) to the problem using different optimality concepts;
- Understanding why the identified alternatives are optimal;
- Test the sensitivity of candidate solutions to the parameters used in the analysis; and,
- Present the results of the analysis in graphical and numerical formats.

7.3.2. Selection of Alternatives

The first step in the decision-making analysis is the selection of alternatives. The alternatives should be chosen to represent real scenarios, on which we can take decisions about; not a sensitivity analysis in which we change one or many parameters, to see the impact in the results, like for instance a change in the discount rate or in the future escalation of the prices of gas. We cannot control these changes, so we can only observe the impact in the results, and select the alternatives with less uncertainty.

On the other hand, for scenarios, such as the limitation of gas from a particular year or the decision to force the construction of some nuclear or coal units, we can study the impact of these decisions with the DAM methodology. Table 7.27 shows the selected alternatives for the decision making study.

Table 7.28 shows the data extracted from DECADES for these alternatives in order to perform the DAM analysis.

Table 7.27 Selected alternatives for the dam study

Case Number	Alternative	Description
106	Base Case	5% growth rate, conservative cost for nuclear, moderate price escalation for fossil fuels, no supply limit for natural gas, 10% discount rate, reliability (LOLP) 3 days/year
68	Limitation CC	Case on limitation of the input number of CC units of 546 MWe to 3 units/year
70	Limitation Gas	The annual gas supply is limited to the level demanded in 2010
74	Forced Nuclear	Includes one nuclear power plant of 1300 MWe forced into the electric system in the year 2012
73	Increased Reliability	The reserve margin and/or the cost of the energy not served (ENS) are defined to increase the reliability (LOLP) to 1 day/year
66	Decrease Reliability	The reserve margin and/or the cost of the energy not served (ENS) are defined to decrease the reliability (LOLP) to 5 days/year

[29] A. D. Athanassopoulos and V.V. Podinovski , Dominance and potential optimality in multiple criteria decision analysis with imprecise information, Journal of Operations Research Society, **48**:142–150, 1997.

The first scenario (Base Case) will represent a free expansion of the electricity system with no limitation to gas availability or the construction of combined cycle plants.

In the second and third scenarios we have a limitation to these parameters in the form of restricting the construction of 546 MWe combined cycle gas units (CC-546) to 3 units per year and limiting the level of input of gas to that of 2010. These two scenarios will represent the possibility that Mexico will have restrictions in the future in gas availability due to lack of funds for the development of a gas infrastructure in the country or problems with the gas imports.

The fourth scenario will represent the impact of the forced introduction of one nuclear unit of 1,300 MWe in the year 2012.

Finally the last two scenarios will represent the impact of increasing or decreasing the reliability of the system from 1 day/year to 5 day/year of loss of load probability (LOLP). The base case is the reference case with reliability of 3 day/year.

Table 7.28 Final structure of the decision-making analysis

Alternatives/Criteria	Cost (Present Value)	CO_2 emissions	SO_X emissions	NO_X emissions	Particle emissions	Stirling index
	M$	million ton/PV	million ton/PV	million ton/PV	million ton/PV	million ton/PV
Base Case (No. 106)	53 124.55	3 380.73/ 1 064.30	20.46/ 10.61	7.18/ 2.53	1.13/ 0.61	0.904
Combined cycle Limitation (No. 68)	54 266.12	3 686.21/ 1 105.11	22.79/ 11.09	9.10/ 2.77	1.33/ 0.65	1.213
Gas limitation (No. 70)	55 870.50	4 063.52/ 1 153.72	23.80/ 11.20	11.64/ 3.10	1.46/ 0.66	1.248
Forced Nuclear (No. 74)	53 530.67	3 331.20/ 1 056.31	20.43/ 10.60	7.11/ 2.51	1.13/ 0.61	0.955
Increase Reliability (No. 73)	53 230.12	3 369.47/ 1 062.36	19.93/ 10.52	7.14/ 2.52	1.10/ 0.61	0.890
Decrease Reliability (No. 66)	53 089.17	3 389.25/ 1 065.39	20.88/ 10.66	7.21/ 2.53	1.16/ 0.62	0.914

These six scenarios will be compared from the point of view of cost, emissions and a third parameter called *diversity index* which will be explained as follows: we know the objective of the *diversification* of the system is among other things, to decrease the risk of a high volatility in the prices of fossil fuels such as gas, and its impact on cost. So to diversify our system, we have to introduce other fuels such as coal, nuclear or renewable energies, in order to have more stable overall prices.

A study carried out for Scottish Nuclear in September 1994[30], based in portfolio analysis, does implicitly predicts that competitive power markets provide less diversity. The study argues that it is advantageous for society to insure itself against the risk of price increases from fossil fuels by opting for diversity, and notably by using non-fossil, especially nuclear energy, as insurance.

So in the case of power plant investment decisions, the trade-off is made between low expected prices with a high level of uncertainty, and higher expected prices but with a lower level of uncertainty. The, adding of some higher-cost generating options act as an "insurance policy" against large price increases or "oil shocks" in fuel consumed in low cost plants.

A diversity index developed by Stirling[31] was used to describe the diversity of the scenarios and was included in Table 7.28. The so-called Stirling index was used as an indicator of energy supply diversity. The index H was calculated for the mix of the capacity resulting in the final year of the study for the selected expansions using the formula:

$$H = -\sum_i p_i \, \mathrm{Ln}(p_i)$$

where p_i represents the proportion of installed capacity i in the total supply mix.

In order to define the value of one unit of this index for the DAM analysis, some methodologies were discussed. These methodologies can be based on the diversification obtained in the different scenarios, during the optimization of the expansions or in other methods like the direct calculation of the security externality or the estimated financial coverage of the gas prices. In the following section we will describe these methodologies.

7.3.3. Definition of criteria and criteria weights

In traditional methodologies, the environmental costs caused by pollutants are added to the economic costs required for the implementation of a decision alternative. The former are calculated by multiplying the levels of pollutants (*e.g.* in millions of tons) by the estimated unit damage costs of the pollutants (e.g. in US$ per ton).

An apparent weakness of this approach is that the unit damage costs have to be estimated precisely and this is clearly impossible because of the complexity of the task and the presence of uncertainty. To overcome this problem the unit damage costs may be varied and the decision analysis repeated a few times to test the sensitivity of the results to the assumed costs. However it is not often clear to what extent should the unit costs be varied and, more important, it is not possible to perform decision analysis for all feasible variations of the unit costs because there are infinitely many such variations.

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[30] Scottish Nuclear, "Diversity in UK Electricity Generation: A portfolio Analysis of the Contribution of Nuclear" ERM, London, UK, 1994.

[31] Stirling, A., "Diversity and Ignorance in Electricity Supply Investments", Energy Policy, March 1994.

The DAM module of DECADES was specifically designed to address this situation. It assumes that the unit damage costs are not exactly known but some ranges for them could be specified. Such ranges for the emissions of CO_2, SO_X, NO_X, and particles are used as the starting point for the scenarios are shown in the Table 7.29.

The ranges for the unit damage costs of the environmental externalities shown in Table 7.29 were obtained from the ExternE study for Spain and Italy. These ranges were adjusted by the GDP per capita of the countries, to reflect the difference in economic development.

Table 7.29 Unit damage costs of pollutants

Pollutant	**Unit Cost**
	\$/ton
CO_2	18 - 100
SO_x	1 155 - 3 300
NO_x	1 265 - 3 850
Particles	1 210 - 5 775
Diversity	million \$/unit
Stirling Index	1 000 - 50 000

With respect to the weight of the diversity index, the calculation can be made following three different approaches and comparing the results to obtain a range of values to be used in the DAM analysis:

(1) In the first approach two expansion scenarios are compared: one in which the Base Case is fixed in terms of the capacity's mix, and an increase in the price of gas results in higher prices than expected for the Base Case optimization. This case is compared with an optimum expansion assuming these same high gas prices, to obtain the value of one unit of diversity through the following equation:

$$P = \frac{C_1 - C_2}{H_2 - H_1}$$

where: C_1 = Cost of fixed scenario (Base Case) without diversification, with high gas prices

C_2 = Cost of same scenario with high gas prices, allowing optimization (e.g. diversification)

H_1 = Lower Stirling Index for scenario with low diversification

H_2 = Higher Stirling Index for scenario with high diversification

P = Potential economic risk due to lower diversification e.g. security externality.

(2) In the second approach one should estimate the cost of the security externality caused by a lack of diversity, produced by an interruption in the supply of gas or higher prices than expected. In these scenarios it can take some time before the system will optimize again to the new conditions, changing the fuel of the installed capacity or changing the sources of supply (e.g. from exported gas to domestic production). These externalities were studied for the oil prices and were found to be in the order of magnitude of 1 to 3% of the oil prices.

(3) Finally it is possible to obtain another value from the financial coverage necessary to assure a certain level of prices: the cost of insurance of a certain levelized price over a period of time. This option has been under study by the electricity utility and a value recommended to be used is of the order of 0.50 US$ per million BTU over a levelized price of 4.00 US$ per million BTU of the gas to be used as fuel.

Using these methodologies we obtained a conservative range for the value of one unit of the Stirling Index that goes from 1,000 to 50,000 million US$ per unit.

In any event and given the uncertainty of this value, we decided to make two DAM analyses: one with a diversity value of zero and the other one with increasing values of diversity to observe the change in the ranking of the expansion scenarios.

The resultant emissions for these pollutants in the six scenarios are shown in the Figures 7.11, 7.12, 7.13 and 7.14. In all these figures we can see a common pattern of lines up to the year 2012 in which the scenarios will change. The highest emission line is the gas limitation scenario (Case No. 70) and the second highest is the limitation of combined cycles scenario (Case No. 68). All the other lines are more or less following the same pattern, with small differences. For more details of the levels of annual emissions for each case, see Appendix V.

In Figure 5.11 we can see that the cleanest alternative in terms of CO_2 are the Base Case and the forced nuclear. Gas limitations, will produce the worst scenarios due to the introduction of coal as a fuel substitute. The other scenarios are in the middle of these two extreme scenarios. There is an increasing trend in the emissions for all the scenarios.

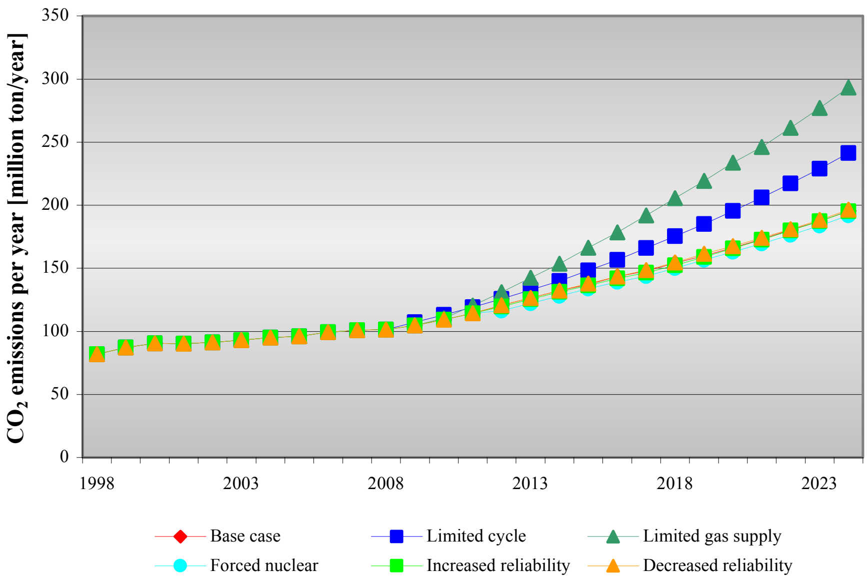

Figure 7.11 CO_2 emissions.

For the Figure 7.12, for the SO_X emissions, one can observe that increasing the reliability of the system will give the cleanest scenario, even better than the Base Case. This is due to the fact that one will be dispatching the more efficient plants with a larger number of units. The reverse is shown as one have a decreasing pattern in the reliability of the system: more pollution due to dispatching a smaller number of plants. The gas limitation cases will give more emissions than the Base Case and the other cases will give comparable emissions.

Also in Figure 7.13 we can see that the cleanest alternative in terms of NO_X are the base case and the forced nuclear, the emissions follow the same trend as in the above case.

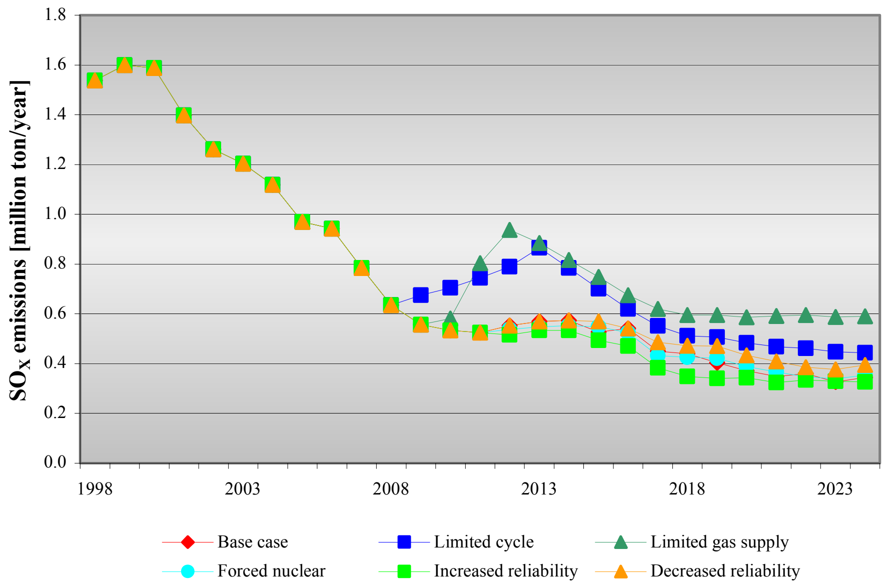

Figure 7.12 SO_X emissions

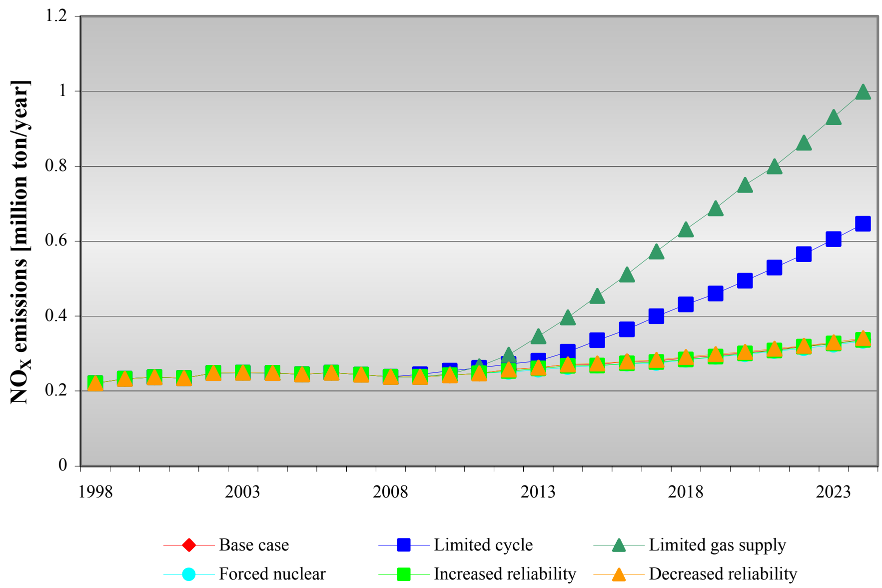

Figure 7.13 NO_X emissions.

In Figure 7.14 for particles we get a similar group of lines with a decreasing trend similar to the SO_X emissions.

From the analysis of these figures and the analysis of the total emissions tables shown in the Appendix V, and Figures 7.11 to 7.17 we can draw the following conclusions:

- If we limit the CC-546 plants entering the system (Case 2), we will obtain a higher cost (+2.1 %), than for the Base Case and more pollution if we use coal as a fuel for dual plants.

- If we limit the use of gas (Case 3) the cost of the expansion is even higher (+5.2%) and also the pollution is higher.

- If we introduce a nuclear unit (Case 4) in the system we will see a slight decrease in the pollution with respect to the Base Case, but a slight increase in cost and considering the cost of externalities, this solution can be better, from the point of view of the costs, than the Base Case.

- If we increase the reliability of the system (Case 5), this solution is as clean as the Base Case, in terms of pollution.

- If we decrease the reliability (Case 6) of the system, we will get a slightly higher pollution but lower cost.

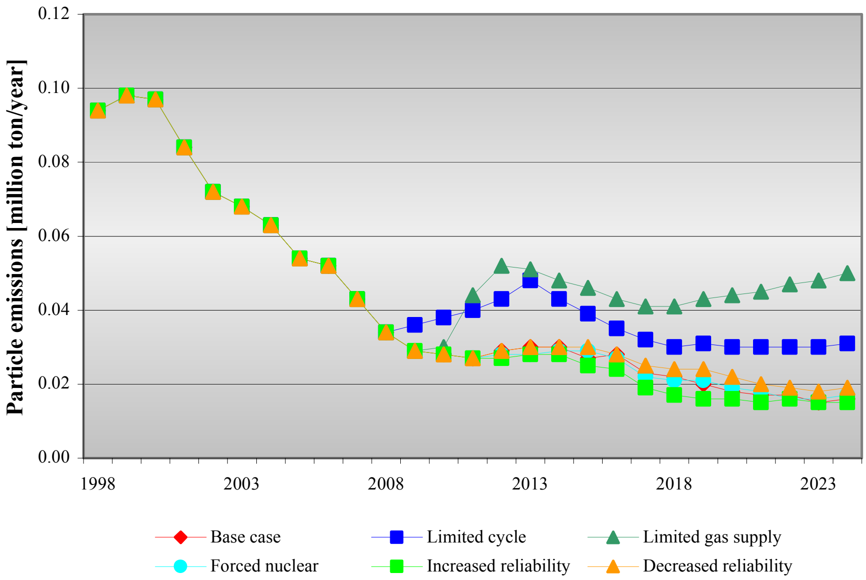

Figure 7.14 Particle emissions.

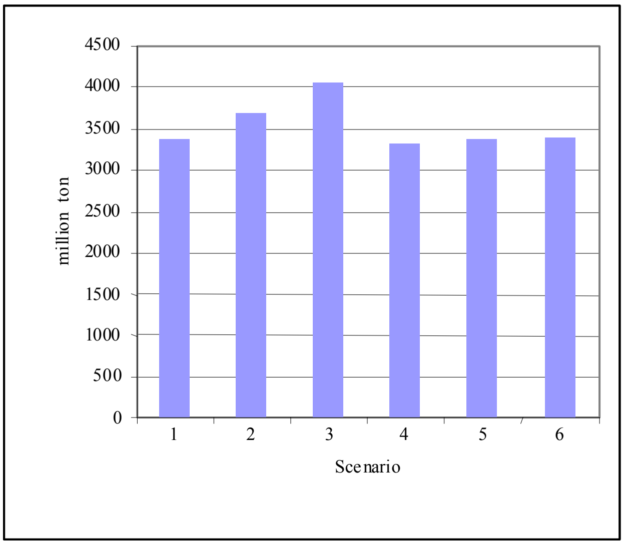

Figure 7.15 Total CO_2 emissions.

7.3.4. Results of the analysis with the DAM Module

Using the above information and the DAM module of DECADES, we obtained the following results:

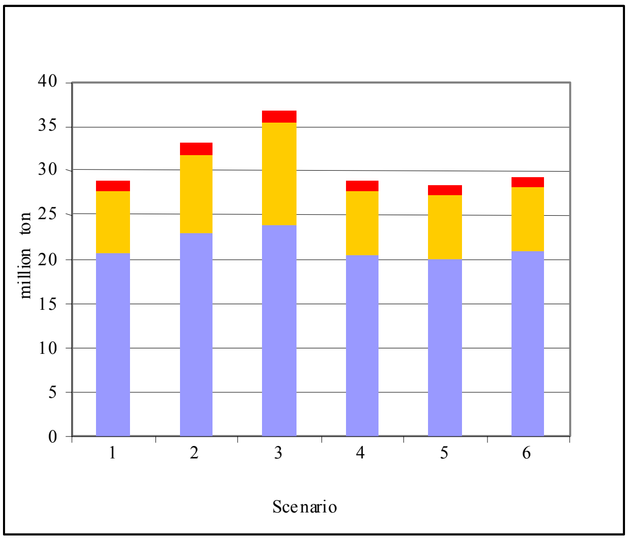

Figure 7.16 Total of other emissions.

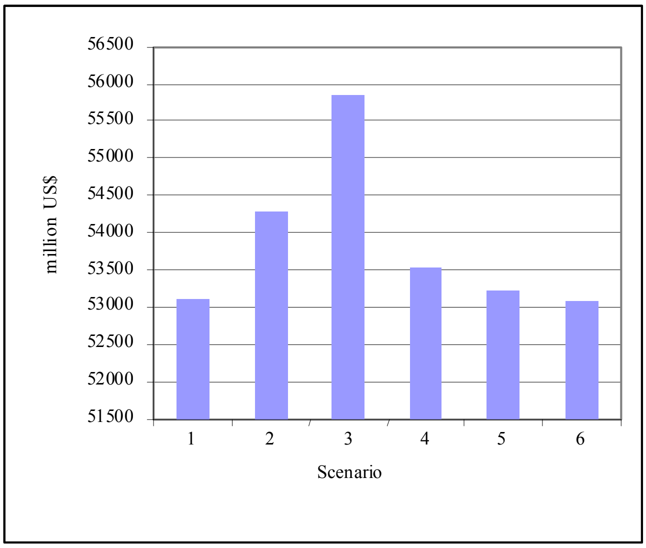

Figure 7.17 Total cost.

7.3.5. Pareto analysis

In the Pareto Analysis the scenarios are compared for the full range of values, in terms of all the criteria and the best scenario is that which is better in all the criteria, for all the range of values in the analysis. For this analysis no Pareto dominance was found, which means that no option is better than another one, in all its attributes *e.g.* one option is better in terms of cost but worst in terms of emissions or diversity. This is represented by a yellow color in the screen of comparisons (Figure 7.18).

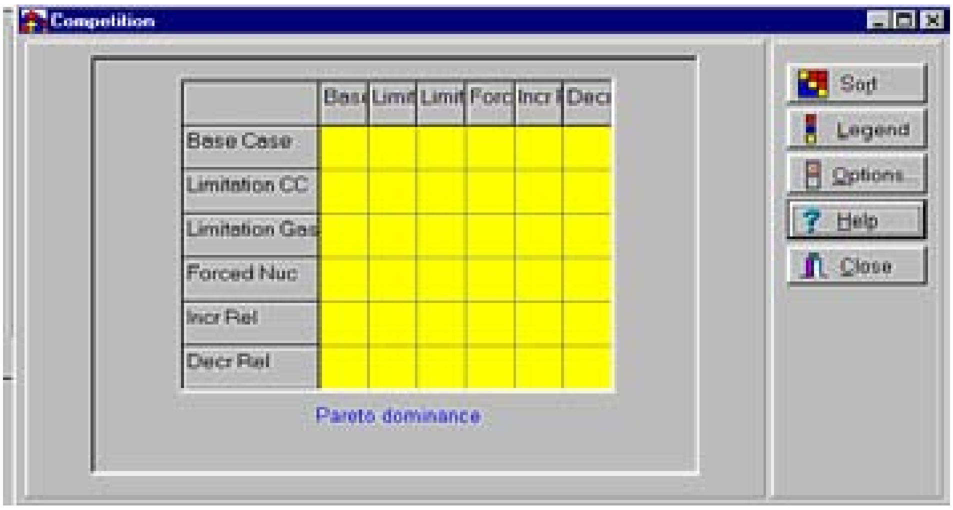

Figure 7.18 Pareto comparisons of the scenarios.

7.3.6. Competition analysis

In the Competition analysis we divided our analysis in two parts: the first part was giving no value to the diversity index and the second part giving a range of values to this parameter which is the one with higher uncertainty. For this latter case the analysis will found the value at which the diversity parameter will change the ranking of the scenarios. This was decided because some experts think that diversity per se has no value or even could have a negative value if we don't have the level of infrastructure in the system needed to introduce a new technology.

In the first analysis the forced nuclear and the increased reliability scenarios were potentially optimal and all the rest were not (Figure 7.19). This is an expected result because the Base Case or the Decreased Reliability scenarios, which are clear winners in purely economic terms, are not potentially optimal if the emissions are taking into consideration, since the difference in cost is marginal between these scenarios. The higher the cost of the CO_2 emissions, the more robust is this conclusion, and at a cost of approximately 92.00 US$ per ton CO_2, the forced nuclear option is optimal. This value was obtained performing the "what if?" analysis of the module. A SO_X study was made performing the "what if?" analysis but did not change this conclusion and the other pollutants have even a smaller impact. In this case some red and blue squares appear on the screen of comparisons, meaning a red square that the alternative in the row is better than the alternative in the column and the opposite for a blue square meaning that the alternative in the row is worse than the alternative in the column.

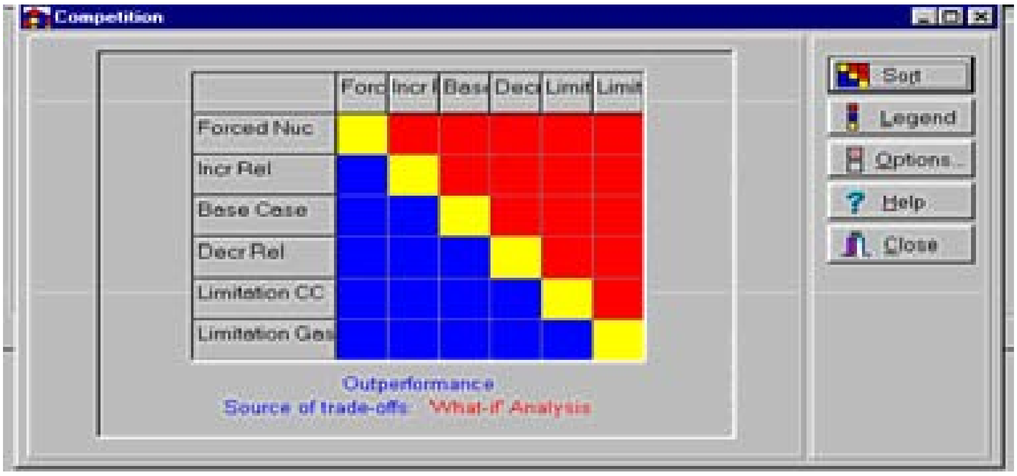

Figure 7.19 Comparison showing optimal solution for emissions.

If we introduce the diversity parameter in the second part of the analysis (Figure 7.20), at a value of 4 500 million US$ per unit of diversity we can see a change of ranking and the limited combined cycle (LCC) scenario becomes potentially optimal followed by the forced nuclear scenario. At higher values of this parameter of 26,000 million US$ this solution becomes more robust and at 33,000 million US$, the LCC scenario is optimal. Also in this second analysis the Base Case expansion was found not optimal.

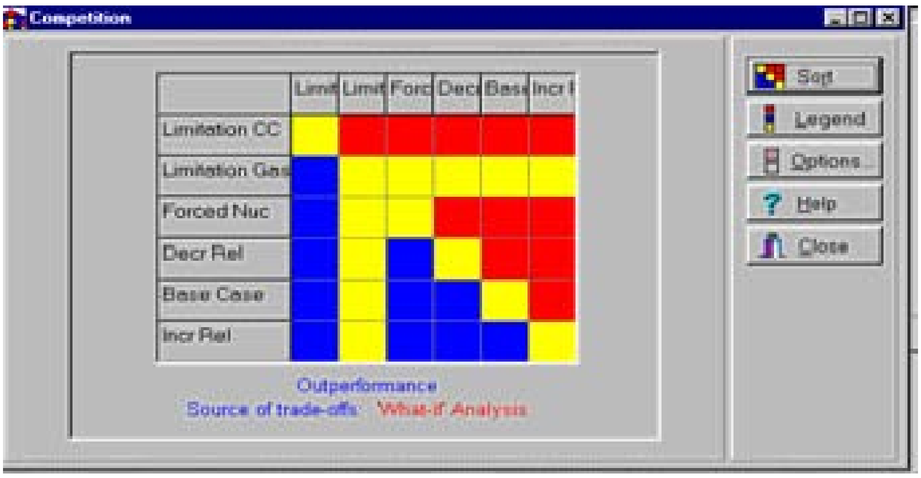

Figure 7.20 Competition showing optimal solution for diversity.

7.3.7. Conclusions of the DAM analysis

We know that in terms of the pure economic analysis *e.g.* considering the total cost of the expansion scenarios, the optimal solution is the Base Case or the decreased reliability scenarios, which is even more economic. But these decisions have the hidden costs of the environmental externalities (CO_2, SO_X, or other emissions), plus a possible security or diversification externality, which we have tried to understand and study. It is important to show the limitations of these scenarios in terms of environmental and social costs.

If we internalize the environmental externalities of the emissions, not only for the power plant but for the whole energy chain considered, then the cleaner expansions (considering the forced nuclear expansion or increasing the reliability of the system), become potentially optimal and at the higher range cost of the CO_2, the forced nuclear expansion solution becomes optimal. This is not a surprising result since the nuclear unit is a zero emitter of greenhouse gases and if its operation starts in 2012, then a considerable amount of pollution is avoided. Using renewable resources such as wind power, which may have even better capital cost and construction periods, can produce the same effect. A study is under way to assess the introduction of such renewable resources, but was not included in this report.

On the other hand, if diversity is considered as an additional important component parameter, the options with higher diversity index become more competitive, and again the forced nuclear expansion and the limited combined cycle (LCC) scenarios are potentially optimal, being this last scenario optimal at the higher values of the diversity index. In both analysis the forced nuclear scenario (and equivalent forced renewable scenario), appear as good candidates for a reduction in environmental emissions and increasing the diversity of the system. Probably an optimal solution from the point of view of both emissions and diversity could be the introduction of a forced renewable scenario in the short term, and then a forced nuclear scenario in the longer term.

8. CONCLUSIONS

The first type of conclusions refers to the attainment of the objectives of the project. The country specific data base (CSDB) for Mexico was created; the initial screening of the candidate technologies for the electric system expansion was done in terms of their technical performance, economic competitiveness and environmental impacts; comparative assessment of full energy chains was the most difficult task of the project, but nevertheless was completed although with some delay due to the amount, detail and complexity of the data required; finally, the comparative assessment of electricity system expansion strategies until 2025 was successfully completed, with one base case and 14 alternatives considered.

The second type of conclusions is related to the usefulness of the tools supplied by the IAEA to the Government of Mexico and their use in future studies. Although CFE had for some years been using the WASP module for electric system expansion analysis, the supply of the DECADES package with the additional VALORAGUA and the DAM models has increased qualitatively the capacity for analysis of the hydro-thermal interaction and of the environmental impacts of the electrical generation system. Also SENER, IIE and UNAM have benefited from the availability and detailed knowledge of these tools because they can be used skillfully in further studies.

The third type of conclusions refers to the synthetic analysis of the main results of the system level expansion study and the DAM program. In this respect, the basic expansion of the interconnected system would be based on natural gas fired combined cycle units, with some gas turbines for peak demand hours. Nonetheless, the possibility of natural gas prices increases makes it desirable to consider some diversification using alternative technologies such as coal fired dual units, fuel oil units, and nuclear units. In such cases the total discounted costs can increase but a higher diversification is provided, the dependence on foreign fuel sources supply is reduced increasing the independence of this strategic sector. Moreover, some environmental benefits can be obtained as well, such as lower CO_2 emissions in the case of nuclear units.

The fourth type of conclusions to be derived from the study is the need for SENER, CFE, IIE and UNAM to analyze with much more detail the issue of economic, environmental, social and political impact of the diversification of the mix of technologies for the long term expansion of the electric system in Mexico. This conclusion arises from the vulnerability that exists in case of limitations in the supply of natural gas or in the increase of their prices.

Finally, in context of diversification it can be recommended that SENER, CFE, IIE and UNAM study the possible economic and environmental benefits of incorporating more wind, solar and geothermal units as candidate technologies for the expansion of the electric system. The results of these studies could indicate the need to incorporate wind and solar technologies in the COPAR document of CFE as well as in the outlook of the electric sector published by SENER [5].

Appendix I.

ENVIRONMENTAL LEGISLATION AND POLICIES

I-1. Environmental legislation and policies

The national environmental policy has as objectives, among others, preservation, restoration and environment improvement, protection of natural areas, exploitation of natural resources and prevention and control of pollution of air, water and grounds[32]. In order to implement this policy, the Ministry of Environment, Natural Resources and Fishing (SEMARNAP) currently the Ministry of Environment and Natural Resources (SEMARNAT), in coordination with the Ministry of Energy (SENER) and the Ministry of Commerce and Industrial Promotion (SECOFI), must regulate activities that the Constitutional Article 27 reserve to the nation, related to exploration and exploitation of the natural resources (geothermal and hydraulic, among others) when these activities can originate ecological imbalances or damages to the environment. Their instruments are:

- Law general of Balance Ecological and Environment Protection, which it anticipates economic incentives to promote technological innovation and to penalize polluting agents and self-regulation schemes that foment the co-responsibility and initiative of the private sector

- The Mexican Norms (NOM) in the matter of environmental protection, being one of the fundamental aspects of the ecological policy.

Critical areas are defined through the environmental standard (NOM-085-ECOL-1994). This standard regulates, by zone and capacity, the maximum allowed levels of emission to the air of total suspended particles, SO_2, NO_X and smoke, originated by the combustion of fossil fuels (solid, liquid and gaseous) in equipment located at fixed sources.

The standard defines by municipality three different areas of application: The first area, The Metropolitan Area of Mexico City is considered as critical, also the cities of Monterrey and Guadalajara in the states of Nuevo León and Jalisco, respectively. In addition two border cities (Tijuana, Baja California and Ciudad Juárez, Chihuahua), located at the Mexico-United States of America border, are considered as critical.

Besides the already mentioned cities there are four industrial corridors that are considered as critical areas, these corridors are: Coatzacoalcos-Minatitlán, in the State of Veracruz; Irapuato-Celaya-Salamanca, in the State of Guanajuato; Tula-Vito-Apasco in the States of Hidalgo y México; and Tampico-Madero-Altamira, in the State of Tamaulipas. The rest of the country constitutes the third area.

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[32] Electrical Sector Prospective Brief 2000-2009, pages 34–36

Appendix II.

ENERGY AND FEEDSTOCK CONSUMPTION

I-2. Industrial and transport sub-sectors

I-2.1. Energy and feedstock consumption

I-2.2. Industrial sub-sectors

	Iron and Steel			PEMEX Petrochemicals			Chemicals		
	1999	2000	2001	1999	2000	2001	1999	2000	2001
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Non associated gas	49.008	67.622	64.798	52.613	49.870	50.973	31.041	41.719	42.230
Natural gas	54.102	70.297	44.824	58.082	51.844	35.261	34.268	43.370	29.213
Coke	86.885	76.500	71.784						
LPG	0.908	0.007	0.006				1.356	0.774	0.650
Gasoline				0.114	0.096	0.085			
Diesel	1.284	1.041	0.827	0.561	0.522	0.474	5.585	4.946	4.153
Fuel oil	20.828	16.535	13.143			0.047	41.983	38.107	31.996
Electricity	31.040	33.576	26.687	58.757	52.462	35.867	21.801	21.878	18.369

Source: JQM, prepared on the basis of the National Energy Balances 1999-2001, Secretaría de Energía, México.

	Cement			Mining			Glass		
	1999	2000	2001	1999	2000	2001	1999	2000	2001
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Non associated gas	5.215	3.907	3.773	12.479	13.537	15.567	10.467	11.373	12.060
Natural gas	5.758	4.061	2.610	13.775	14.072	10.769	11.555	11.824	8.342
Coke		23.312	34.188	5.322	13.134	6.762	1.056		
LPG			0.002	4.507	2.813	2.683	0.196	0.108	0.102
Diesel			0.002	4.790	4.936	4.708	1.850	0.118	0.116
Fuel oil			0.002	5.633	6.987	8.333	1.855	2.654	3.012
Electricity	14.404	13.904	13.533	19.655	20.880	19.917	4.232	4.635	4.783

Source: JQM, prepared on the basis of the National Energy Balances 1999–2001, Secretaría de Energía, México.

	Fertilizers			Malt and Beer			Bottled Waters		
	1999	2000	2001	1999	2000	2001	1999	2000	2001
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Non associated gas	3.634	1.698	1.684	3.764	3.930	4.774	0.914	1.229	1.443
Natural gas	4.012	1.765	1.165	4.156	4.085	3.303	1.008	1.277	0.998
LPG				0.088	0.386	0.512	1.406	0.796	0.775
Diesel	0.113	0.143	0.092	0.441	0.102	0.066	2.928	2.605	2.537
Fuel oil	2.961			4.802	6.354	6.348	1.185	1.891	1.916
Electricity	1.483	0.753	0.694	1.877	1.242	1.335	2.368	2.681	2.611

Source: JQM, prepared on the basis of the National Energy Balances 1999-2001, Secretaría de Energía, México.

	Automotive			Construction			Rubber		
	1999	2000	2001	1999	2000	2001	1999	2000	2001
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Non associated gas	1.441	1.536	1.772				1.340	1.489	1.842
Natural gas	1.591	1.597	1.225				1.480	1.547	1.274
LPG	3.126	1.595	1.526				0.010	0.005	0.005
Diesel	0.311	0.311	0.298	5.601	6.306	6.020	1.001	1.016	1.043
Fuel oil							0.539	0.609	0.646
Electricity	4.668	4.747	4.541	1.614	1.421	1.356	1.315	1.321	1.356

Source: JQM, prepared on the basis of the National Energy Balances 1999–2001, Secretaría de Energía, México.

	Aluminum			Tobacco			Other		
	1999	2000	2001	1999	2000	2001	1999	2000	2001
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Non associated gas	1.748	0.662	0.677	0.133	0.083	0.068	34.213	18.178	0.031
Natural gas	1.930	0.689	0.468	0.146	0.087	0.047	37.769	18.897	0.021
LPG	0.313	0.031	0.040		0.001	0.002	25.842	34.074	32.186
Kerosene							0.519	1.540	2.162
Diesel		0.013	0.011	0.004	0.003	0.003	25.500	31.357	30.836
Fuel oil				0.057	0.042	0.099	4.717		17.476
Electricity	1.173	4.164	3.495	0.203	0.150	0.155	194.051	215.729	226.425

Source: JQM, prepared on the basis of the National Energy Balances 1999-2001, Secretaría de Energía, México.

	Paper and Cellulose			Sugar		
	1999	2000	2001	1999	2000	2001
	PJ	PJ	PJ	PJ	PJ	PJ
Sugar cane bagasse		0.209	0.474	86.582	82.381	86.775
Non associated gas	8.762	7.804	7.185			
Natural gas	9.672	8.113	4.970			
LPG	0.497	1.130	0.292		0.002	
Kerosene						
Gasoline						
Diesel	4.384	1.086	0.879	0.037	0.143	0.047
Fuel oil	12.891	14.972	14.771	35.252	27.289	28.199
Electricity	9.983	8.798	9.025	0.532	0.496	0.463

Source: JQM, prepared on the basis of the National Energy Balances 1999–2001, Secretaría de Energía, México.

	PEMEX Petrochemicals (feed stock)			Other (feed stock)		
	1999	2000	2001	1999	2000	2001
	PJ	PJ	PJ	PJ	PJ	PJ
Sugar cane bagasse				4.393	4.486	4.731
Non associated gas	21.167	13.555	13.621			
Natural gas	23.367	14.091	9.423			
LPG	0.038	0.020	0.265		0.812	0.840
Gasoline	35.549	31.894	38.716	2.868	2.118	1.685
Kerosene	0.080	0.003	0.019	0.000		
Coke				0.000	12.554	3.640
Non energy products	72.043	78.197	68.290	157.757	85.987	81.244

Source: JQM, prepared on the basis of the National Energy Balances 1999–2001, Secretaría de Energía, México.

I-2.3. Transport sub-sectors

	Road			Air			Sea		
	1999	2000	2001	1999	2000	2001			
	PJ	PJ	PJ	PJ	PJ	PJ			
Non associated gas	0.164	0.102	0.286						
Natural gas	0.181	0.106	0.198						
LPG	35.344	45.241	46.895						
Gasoline	956.154	997.038	1015.138	0.942	0.830	0.753			
Kerosene				114.394	115.107	113.016			
Diesel	365.357	373.237	354.247				41.567	43.364	36.950
Fuel oil							8.424	12.792	8.082

Source: JQM, prepared on the basis of the National Energy Balances 1999–2001, Secretaría de Energía, México.

	Rail			Electric		
	1999	2000	2001	1999	2000	2001
	PJ	PJ	PJ	PJ	PJ	PJ
Diesel	21.868	22.554	20.672			
Fuel oil						
Electricity		0.099	0.087	3.645	3.862	3.984

Source: JQM, prepared on the basis of the National Energy Balances 1999–2001, Secretaría de Energía, México.

Appendix III.

ENERGY PLANNING AND POLICY IN MEXICO

I-3. Organization and policies in the energy sector

I-3.1. Structure of the Mexican energy sector

The institutional structure for planning and development of the Mexican energy sector is shown in Figure C.1[33]. The National Plan of Development, and the Program of Development and Reorganization of the Energy Sector 1995-2000 defines the objectives, priorities and policies that must govern the development of the Mexican energy industry.

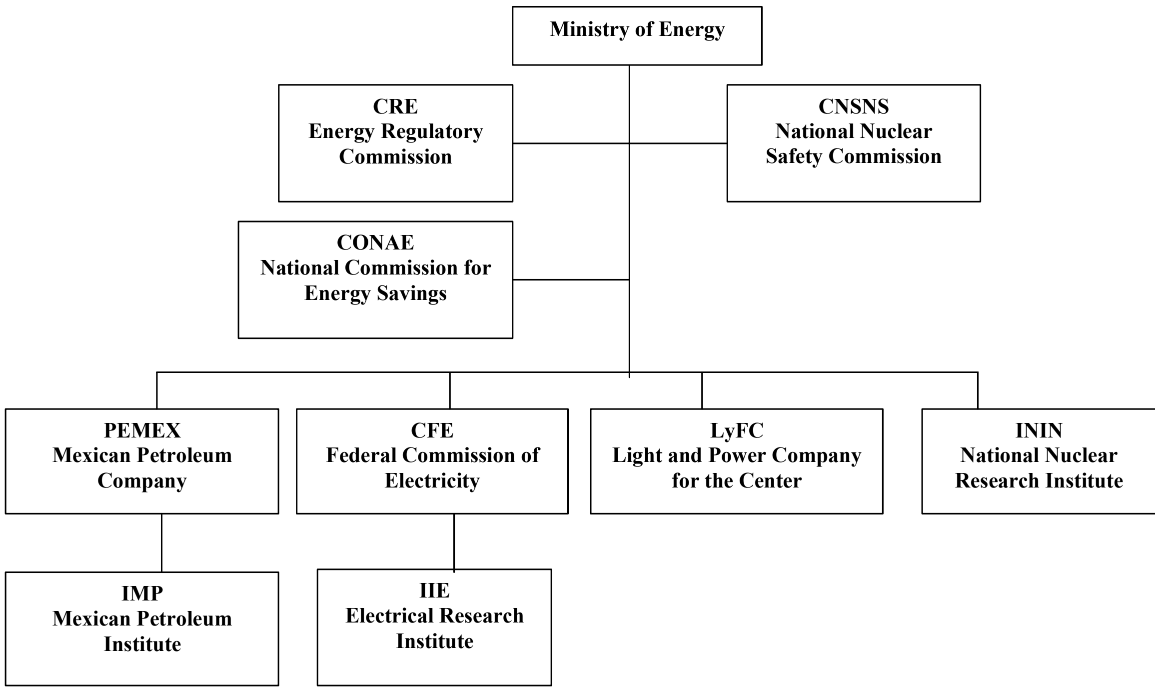

Figure C.1 Structure of the Mexican energy sector.

I-3.2. Ministry of Energy (SENER)

The role[34] of the Ministry of Energy (Secretaría de Energía) is to set up the appropriate energy policy and strategies as well as to exercise the rights of the nation in the matter of energy resources, to guarantee balanced supply of primary energy resources and electricity as public service, for which it will promote private participation in the electricity generation and distribution of natural gas and LPG; to regulate and to set the norms in energy usages, as well as to coordinate activities of state organizations in the energy sector. The institutional vision of the Ministry of energy is to be a highly efficient Federal Executive dependency in design, implementation and evaluation of public policies in the matter of energy, as well as in the coordination of the sectored organizations, to guarantee energy supply for the development of national life.

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[33] http://www.energia.gob.mx/english/energysector.htm

[34] http://www.energia.gob.mx/se/misvis.htm

In order to obtain it, it must train qualified people, being able to fulfill objectives and goals in an effective and efficient way and with an ample sense of pride to be part of this institution and of the energy sector. Also, the Ministry of Energy must have a flexible and modern organic and functional structure that allows fast adaptation to changes of the national and international surroundings; vanguard infrastructure in computers and telecommunications to support the execution of its attributions and functions; and a transparent handling of the assigned budgetary resources for its operation.

The CRE (Comisión Reguladora de Energía) contributes to safeguard the benefit of public services, fortifies a fair competition, protects user's shares, propitiates a suitable national cover and takes care of the reliability, stability and security in the supply and services[35]. The CRE has proposed to promote efficient development of the gas and electrical energy sectors in benefit of the users. In order to carry out this objective, the CRE regulates the natural and legal monopolies in the electrical and natural gas industries in Mexico. The regulating activity has to be conducted in transparent, impartial, and uniform way, based in clear and stable norms. The CRE has developed five basic principles of operation for its regulating activity:

Clarity: the Commission establishes simple and precise rules for the regulated activities;

Stability: the rules are in agreement with a long term vision of the industry to promote the required investments;

Transparency: commissioners, who deliberate in collegian way, take the decisions and their resolutions are registered in a public registry;

Fairness: the law application does not distinguish between public and private entities, the dispositions are of general application and consistent and predictable criteria are applied; and,

Autonomy: the CRE decisions are taken in accordance with objectives and long term vision established in applicable legal dispositions, independently of political conditions.

In Agreement with the National Plan of Development, the regulating activity of the CRE does not have to obstruct or to restrict the productive activity of the individuals, but to promote it. Through an equitable, transparent and efficient frame of regulation, it will be managed to stimulate the competitive capacity of the companies, to encourage the productive investment and to propitiate the creation of more and better jobs in both industry and services

I-3.3. National Commission for Energy Savings (CONAE)

The institutional mission of the CONAE (Comisión Nacional para el Ahorro de Energía) is design, promote and foment guidelines and actions in matter of saving and efficient use of energy and exploitation of renewable energies in the country; to offer technical assistance in this matter to public, private and social sectors; as well as to concert implantation of energy efficiency norms[36].

[35] http://www.cre.gob.mx/cre/mision.html
[36] http://www.conae.gob.mx/quees/mision.html

I-3.4. National Commission of Nuclear Security and Safeguards (CNSNS)

The mission of the CNSNS (Comisión Nacional de Seguridad Nuclear y Salvaguardias) is to assure that activities, where nuclear fuels, radioactive and ionizing radiation sources are involved, are realized with maximum security, considering current technological developments[37].

I-3.5. Mexican Petroleum Company (PEMEX)

The institutional mission of PEMEX (Petróleos Mexicanos) is to administer in a rational way the hydrocarbons, which are property of the nation, and its own assets in a safe and sustainable way, as well as efficiently supply to the country necessities of petroliferous products, natural gas and basic petrochemical products[38]. PEMEX is the greatest company of Mexico and one of the ten largest of the world in terms of assets and income. Based in the level of reserves and its extraction capacity and refinement, PEMEX is among the most important oil companies worldwide[39]. The PEMEX activities include exploration and operation of hydrocarbons, as well as production, storage, distribution and commercialization of petroliferous and petrochemical products. By virtue of which in accordance with the Mexican legislation these activities correspond in exclusive right to the State, PEMEX is a decentralized public organization.

I-3.6. Federal Commission of Electricity (CFE)

CFE (Comisión Federal de Electricidad)[40,41] is in charge of assuring the supply of electrical energy in the country, in suitable conditions of amount, quality and price, providing careful attention to the users of the service, as well as protecting the environment, promoting the social development and respect the values of the population where the electrification works are located.

I-3.7. Light and Power Company for the Center (LyFC)

According to the guidelines that are indicated in the Development Plan 1995-2000 and its correlative sector program, the mission of LyFC (Compañía de Luz y Fuerza del Centro) is to provide, in its area of competition, public service of electrical energy as strategic activity that helps economic and social development[42,43].

I-3.8. National Nuclear Research Institute (ININ)

The mission of the ININ (Instituto Nacional de Investigaciones Nucleares) is to contribute as a National Laboratory to the research and development of nuclear sciences and its applications, making research of excellence and providing quality services, besides to contribute to the formation of high-level researchers[44,45].

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[37] http://www.cnsns.gob.mx/
[38] Secretaría de Energía, Manual de organización general de las entidades paraestatales 2000: sector energía, p. 142
[39] http://www.pemex.com/conozca.html
[40] http://www.cfe.gob.mx/git/infomis.html
[41] Secretaría de Energía, Manual de organización general de las entidades paraestatales 2000: sector energía p. 35
[42] http://www.lfc.gob.mx/mision.htm
[43] Secretaría de Energía, Manual de organización general de las entidades paraestatales 2000: sector energía, p. 122.
[44] http://www.inin.mx/inin/Dirgral/indiceg.html
[45] Secretaría de Energía, Manual de organización general de las entidades paraestatales 2000: sector energía, p. 110

I-3.9. Mexican Petroleum Institute (IMP)

The mission of the IMP (Instituto Mexicano del Petróleo) is generate, develop, assimilate and apply scientific and technological knowledge, to promote the development of specialized human resources to support the national oil industry and to contribute to the development maintained and sustainable of the country[46,47].

The IMP vision is to be an institution dedicated fundamentally to research and technological development, centered in the generation of knowledge and abilities critics for the oil industry, that transforms knowledge into industrial realities, that offers and commercializes services and products of quality and with high technological content; to be an institution of recognized national and international prestige, organized to respond with agility to the change and able to maintain its financial self-sufficiency.

I-3.10. Electrical Research Institute (IIE)

The mission of the IIE (Instituto de Investigaciones Eléctricas) is to promote and support innovation through value-adding applied research and development to increase the competitiveness of Mexico's electric industry. The institutional vision of the IIE is to be a leading institute formed by prestigious scientific and technical groups, whose work provides benefits to the national electric industry and to be a source of income for the sustainment of technological endeavors[48,49].

I-4. Electric Energy Planning Procedures

In order to determine capacity and location of the new generating power stations, as well as the optimal expansion of the transmission network, is necessary to consider power and energy that are required in each one of the different consumption centers of the country. The starting point is a regional study of the sales of electrical energy, which analyzes the evolution of the sales in each geographic zone and area of the national electrical system. The regional projections are based on complemented statistical studies of tendency with estimations based on requests of big consumers. The studies results of the regional sales are adjusted to tie with the forecasting of regional sales, defined previously with econometric models[50.]

I-4.1. Expansion of the National Electrical System

The expansion of the national electrical system is based on long term planning for the following reasons[51]:

- It takes several years of anticipation to make investment decisions of an infrastructure of electrical generation and transmission. It is because the projects have long periods of maturation. From the date in which the construction of a new power station of generation begins to its entrance in commercial operation, approximately four years on average pass. In the case of transmission projects,

[46] http://www.imp.mx/mision.htm
[47] Secretaría de Energía, Manual de organización general de las entidades paraestatales 2000: sector energía, p. 92
[48] Instituto de Investigaciones Eléctricas, Annual Report 1999.
[49] http://www.iie.org.mx
[50] Secretaria de Energía, Prospectiva del sector eléctrico 2000-2009, p. 78
[51] Secretaria de Energía, Prospectiva del sector eléctrico 2000-2009, p. 87

about three years are needed. In addition, it is necessary to consider the required time for the formulation, evaluation and authorization of the projects.

- Decisions related to the expansion of the electrical system have economic repercussions in the long term, since lifetime of facilities is of the order of 30 years.

For the planning of the electrical system up-to-date information of the feasible projects of generation and transmission is required to be incorporated in the expansion program. This information comes from the studies of identification and evaluation of projects and technologies, which CFE and LyFC elaborate, as well as of other specialized sources. With such information a feasible project catalogue is done and a document denominated "Costs and Parameters of Reference for the formulation of projects in the electrical sector[52]" that contains technical parameters and considered costs of typical projects of diverse technologies of generation and transmission.

The program of expansion of the national electrical system is determined by means of a systematic analysis of diverse configurations of feasible projects, that are evaluated technically and economically and in the frame of the electrical system allows to select the projects which minimize the sum of the updated costs of investment, operation and deficit of supply, in the period of planning (optimal program of expansion). For this process models of optimization and simulation are used.

I-4.2. Margin of reserve

The adopted minimum values for the planning of the interconnected system are the following ones[53]:

- Margin of reserve = 27%

- Margin of operative reserve = 6%

These levels of reserve are considered suitable when there are no restrictions in the transmission network.

For the Baja California area a minimum value is adopted of reserve capacity, after discounting the unavailable capacity by maintenance, whichever is larger:

(a) The capacity of the largest unit, or

(b) 15% of the maximum demand.

For the Baja California Sur area, the total capacity of the two largest units is adopted as the minimum value of reserve capacity.

I-4.3. Analytical tools used in the planning of the energy sector

Descriptions of the analytical tools that are used by the CFE, PEMEX, SENER and Academic Institutions for energy planning at the National and Sectoral level are reported in several

[52] Costos y parámetros de referencia para la formulación de proyectos en el sector eléctrico (COPAR)
[53] Secretaria de Energía, Documento de Prospectiva del Sector Eléctrico) 2000-2009, p. 90

publications by CFE, PEMEX, Academic Institutions, Symposia and Congresses[54]. The reader is referred to such publications for a detailed knowledge and analysis of the analytical tools, their origin and purpose, *status* of development and scope of application.

I-5. Recent energy policy and strategies

I-5.1. Current energy policy

The recent policy focuses mainly on the following objectives[55]:

- Increase the quality of life of the Mexican people;
- Promote a rational use of resources in the context of sustainable development and intergenerational equity;
- Promote investment in productive and feasible projects for Mexico;
- Generate an elastic supply of hydrocarbons;
- Increase productivity in the sector;
- Achieve a competitive pricing policy.

I-5.2. Use of renewable resources

The Federal Government Energy Policy has stimulated the use of renewable resources for the generation of electricity, such as hydroelectric, geothermal, wind, and other energies[56,57]. The CFE has identified a potential 52 900 MW[58] in a diverse hydroelectric exploitation sites throughout the country, of which about 10 000 MW have been harnessed by the CFE and private investors under the modality of self-supply, for industrial as well as municipal use could develop 42 900 MW. This potential store is integrated by projects under divers level of research, which go from identification of hydroelectric potential to develop studies carried out by the CFE in the last few years. The size of these projects is between 20 MW and 700 MW.

With respect to geothermal exploitation sites, there are several such as Los Azufres, in Michoacan, and others, where underground vapor could be used to develop projects for generation of electricity.

The Tehuantepec Isthmus area is known worldwide for its great aeolian potential, estimated in 2 000 MW. At the beginning of 1998, the CRE, awarded self-supply permit of 30 MW for a wind project at La Venta, Oaxaca, as well as an additional permit for another self-supply project of 60 MW in Baja California, which is also an area of very high wind potential.

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[54] Modelos Matemáticos para la Planeación Energética, Quintanilla, J. (Ed), Programa Universitario de Energía, Dirección General de Servicios de Cómputo Académico, UNAM, México,1983.
[55] http://www.energia.gob.mx/english/energysector.htm
[56] http://www.energia.gob.mx/english/oielectricoi.html
[57] More information can be found in the Electrical Sector Prospective Brief 2000-2009, pages 135-139
[58] CFE, Catalog of hydroelectric projects (Catálogo de proyectos hidroeléctricos), June 2000

Appendix IV.

ELECTRICITY PRODUCTION CHAINS FOR OIL AND GAS

I-6. Oil and gas production, processing, transportation and their environmental impacts: A general view

I-6.1. Oil and natural gas chains

Fuel oil and diesel, two by-products of the petroleum industry, are used as boiler fuels in thermal plants for electricity production, but they have other energy applications also. Natural gas, with a carbon to energy ratio that is less than half that of coal, and about two-thirds that of oil, may receive strong attention as a fuel for generating electricity, as is the case at present, when there is need to minimize CO_2 emissions. So far as the greenhouse effect is concerned, this advantage may be put in jeopardy due to releases of methane during the gas extraction, transportation and handling. Therefore, it is necessary to consider the full energy chain and consider that there are options for the reduction of such methane losses. The impacts from the oil and gas chains for electricity generation are associated with the overall activities for the oil and gas exploration, production, processing and transportation.

I-6.2. Oil and gas production

Exploration and production of oil and natural gas, onshore and offshore, have a number of environmental impacts. Fires, explosions and accidental spills are the most common accidents. Accidents and equipment failures can cause harm to workers and environment. These activities require a substantial support in terms of technologies and specialized personnel and are provided from places, as near as possible, to the production field. In the case of offshore production fields these support installations are located on the nearest coastal location putting pressure on the local infrastructure (housing, community services) and social conditions. The sitting of the necessary facilities, such as pipelines, pipelines terminals and platform construction sites, leads to land management problems, since it competes with other possible uses of the coastal zone. For onshore production fields the situation is similar to the offshore ones, however it has the advantage to be inland. Although accidental spills from offshore and on shore operations are, normally, of relative small volumes, some large spills have occurred in the past. Even with careful treatment of effluent discharges and stringent controls to minimize accidental oil spillage, both onshore and offshore oil and gas production result in some discharge to the surrounding environment. Tidal marshes, coastal wetlands, rivers, swamps and sheltered bays are sensitive ecosystems; even low levels of hydrocarbon pollution can originate serious ecological impacts.

Presently, oil and natural gas operations have the tendency to work at higher depths (onshore and offshore) and under harsher environments than in the past. There may be a possibility that higher environmental risks may occur under these conditions, conditions that may be different from those experienced in the past.

Crude oil frequently is associated with large amounts of emulsified brine. After separation, the brine usually is disposed of by re-injection into the earth. However, some brine may be discharged to marine or terrestrial water bodies, which can have serious effects on aquatic ecosystems. During natural gas extraction, there are some leaks. Since natural gas is mainly methane, a strong greenhouse gas, there are some concerns that these leakages can add to the possible risks of global warming.

Besides the already mentioned sources of pollution of air and water, for the analysis we have to take into account other sources of contamination under normal conditions of operation. These additional sources of emissions are related to the energy uses for extraction, reinjection and other services that are needed for the separation of oil and natural gas and its shipment into the storage facilities. Compressors, electricity generators and other equipment require a source of energy for its operations. Electricity, diesel and natural gas can provide the required energy for this equipment. Normally, offshore facilities employee diesel generators to produce the required electricity and mechanical work for their operations.

Once crude oil and natural gas have been separated, at the separation batteries, they are sent, through pipelines, to the storage facilities for shipment into the crude oil processing centers (refineries), to the processing gas plants and preparation for export to other countries.

I-6.3. Oil transportation

Usually, oil has to be transported over long distances, because the area of oil production does not coincide with either the area of processing or demand. Marine transportation and pipelines are the two modes of crude oil transportation.

Marine oil tankers are the most important means of international oil transportation. As in many oil activities, oil transportation has some risks to suffer accidents and, therefore, can have serious effects on the environment and marine life. Wind and ocean currents can move oil for long distances in a relatively short time, and the consequences of a major spillage can be spread over a large area. Oil discharge and cleaning of oil tankers after unloading represent another danger to oceans and coastal ecosystems. Some tankers are filled with water as ballast after the oil is unloaded, and the ballast water becomes contaminated with oil residues. The discharge of water contaminated with oil, before taking a new oil cargo, adds to oil pollution of the oceans. The oil industry has introduced a variety of methods, such as using crude oil instead of water for tanker cleaning, to mitigate such operational pollution.

Oil terminals often are constructed within or near ecologically sensitive coastal areas, such as estuaries. There always exist the risk of oil spillage during the transfer of oil from the tanker or from the marine oil fields to the shore facility. Even in the absence of large scale oil spills the cumulative effect of many small spills and leaks remains in the area. Because oil floats on the sea surface, spilled oil tends to become deposited in the intertidal zone near or on the shoreline, causing many undesirable consequences. Suitable surface treatment agents can be used for the protection of shorelines from the spills. These are emulsifying agents that can be used to disperse the oil in the water; nevertheless ocean waters become polluted.

Compared to marine oil transport, pipelines in general present lesser environmental problems. For offshore facilities they are generally laid on the ocean floor. Burial of pipe lines which lie in less than 100 meters of water is usually required. Doing so minimizes the potential for damage from natural forces and from marine equipment. Onshore, pipelines are laid in trenches. For large distances, remote control valves at varying distances along the pipelines are installed to minimize the possibility of large oil spills, in case of damage. Pipelines which are not buried in the ground can cause disturbances to wildlife. Natural forces, such as earthquakes and corrosion, also have to be considered.

Natural gas consists of methane and other hydrocarbon compounds, and usually is transported in gaseous form through pipelines. The primary risks with gas pipelines are associated with fires and explosions, in particular from pipelines passing through or near heavily populated areas. In addition, pipeline leakage of methane, a strong greenhouse gas; contribute to the potential risks of climate change and global warming.

For ocean transport, natural gas is cooled to its liquid state (liquefied natural gas, LNG) for transport by special LNG tankers. The main environmental effects associated with natural gas liquefaction plants are the discharge of heat to the atmosphere or to fresh or marine waters, depending on the type of cooling system used, and the occasional emission or flaring of some components extracted during gas liquefaction. There is also a possibility of destructive evaporation of LNG if it comes in contact with water.

I-6.4. Oil processing (refining)

Refineries are large industrial installations with air and water emissions, large water requirements for processing and cooling, and risks of explosions and fires. The principal types of airborne emissions are volatile hydrocarbons, sulfur oxides, nitrogen oxides and particulate. Some amounts of carbon monoxide, volatile organic compounds and ammonia are emitted also. In addition, there are important amounts of CO_2 and unburned hydrocarbons due to the energy consumption (oil products, natural gas and electricity) in the different processes. Liquid effluents contain chlorides, grease, ammonia nitrate, phosphate, suspended solids, dissolved solids and trace metals (V, Cr, Pb, Zn, Cu, etc.).

Refineries require large amounts of water, mainly for cooling and various process operations. Each process operation has different water usage and wastewater characteristics associated with it. In addition to process wastewater, ballast water in tanks, storm water runoff and sanitary wastes contribute to the total wastewater load that must be treated before discharge to the environment.

The most significant pollutants present in this waste load are oil and grease, phenols, ammonia, suspended and dissolved solids, sulfites and chromium. Treatment techniques consist mainly of primary separation of oil and solids and neutralization, followed by biological treatment using activated sludge systems, aerated lagoons or oxidation ponds. Unpleasant odor is another potential nuisance in and around refineries. Hydrogen sulfide (H_2S) and mercaptans are the principal malodorous compounds. Even small leakage of these compounds from a refinery can cause unpleasant smells in the surrounding area.

Accidental spills of stored crude oil or refined products can cause severe local environmental impacts, requiring extensive restoration efforts.

The petroleum refining industry converts crude oil into more than 2 500 products, including liquefied petroleum gas, gasoline, kerosene, aviation fuel, diesel fuel, fuel oils, lubricating oils, and feedstock for the petrochemical industry. Petroleum refinery activities start with the receipt of crude oil for storage at the refinery, include all petroleum handling and refining operations, and terminate with storage preparatory to shipping the refined products from the refinery.

The petroleum refining industry employs a wide variety of processes. The composition of crude oil feedstock and the chosen slate of petroleum products largely determine a refinery's processing flow scheme. The refinery flow scheme presented in Figure D.1 shows the general processing arrangement for major refinery processes. The arrangement of these processes will vary among refineries, and not all the refineries will employ all of these processes. Petroleum refining processes having direct emission sources are presented in bold-line boxes on the Figure.

Generally speaking, one can consider five categories of refinery processes and associated operations. These categories are: a) separation processes (atmospheric distillation, vacuum distillation and light ends recovery (gas processing)); b) petroleum conversion processes (cracking (thermal and catalytic), reforming, alkylation, polymerization, isomerization, coking and visbreaking); c) petroleum treating processes (hydrotreating, hydrodesulfurization, chemical sweetening, acid gas removal and deasphalting); d) feedstock and product handling (storage, blending, loading and unloading); and e) auxiliary facilities (boilers, wastewater treatment, hydrogen production, sulfur recovery plant, cooling towers, blow down system and compressor engines).

According to Figure D.1, several of these processes have direct and significant contributions to the air pollution. Bold-line boxes on Figure D.1 identify those processes. The major sources of atmospheric emissions from the vacuum distillation column are associated with the steam ejectors or vacuum pumps. A second source of atmospheric emissions from vacuum distillation columns is combustion products from the process heater. Fugitive hydrocarbon emissions from leaking seals and fittings are also associated with the vacuum distillation unit.

Catalytic cracking, using heat, pressure and catalysts, converts heavy oils into lighter products with product distributions favoring the more valuable gasoline and distillate blending components. All the catalytic cracking processes in use today can be classified as either fluidized bed or moving bed units. Air emissions from catalytic cracking processes are combustion products from process heaters and flue gas from catalyst regeneration. Emissions from process heaters consist of all pollutants. The quantity of these emissions is a function of the type of fuel burned, the nature of the contaminants in the fuel, and the heat duty of the furnace. Among those contaminants are sulfur oxide, carbon monoxide, nitrogen oxides and particulate. Emissions from the catalyst regenerator include hydrocarbons, oxides of sulfur, ammonia, aldehydes, oxides of nitrogen, cyanides, carbon monoxide and particulate.

Thermal cracking processes include visbreaking and coking. Air emissions from thermal cracking processes include coke dust from decoking operations, combustion gases from the visbreaking and coking process heaters, and fugitive emissions.

Particulate emissions from delayed coking operations are potentially significant. These emissions are associated with removing the coke from the coke drum and subsequent handling and storage operations. Hydrocarbon emissions are also associated with cooling and venting the coke drum prior to coke removal.

The utility plant supplies the steam necessary for the refinery. Although the steam can be used to produce electricity (as is the case in most of the Mexico's refinery facilities), it is primarily used for heating and separating hydrocarbon streams. When used for heating, the steam usually heats the petroleum indirectly in heat exchangers and returns to the boiler. In direct contact operations, the steam can serve as a stripping medium or a process fluid. Steam may also be used in vacuum ejectors to produce a vacuum. Emissions from boilers were commented in a previous paragraph.

Sulfur recovery plants are used in petroleum refineries to convert hydrogen sulfide (H_2S) separated from refinery gas streams into the more disposable by-product, elemental sulfur. Emissions from sulfur recovery unit contain sulfur dioxide, carbon monoxide, volatile organic compounds and other reduced sulfur compounds.

Most refining units and equipment subject to planned or unplanned hydrocarbon discharges are manifold into a collection unit, called the blow down system. By using a series of flash drums and condensers arranged in decreasing pressure, the blow down is separated into vapor and liquid cuts. The separated liquid is recycled into the refinery. The gaseous cuts can either be smokeless flared or recycled. Therefore, the combustion of the noncondensables in a flare is a source of emissions. Complete combustion or smokeless burning can be carried out by the addition of steam in the combustion zone of the flare and reduce emissions of nitrogen oxides due to the lowering of the flame temperature.

Refining units operating al high pressure include hydrodesulfurization, isomerization, reforming and hydrocracking. These units require compressor engines (reciprocating and gas turbine) fired with natural gas or some other fossil fuel. Internal combustion engines are less reliable and harder to maintain than steam engines or electric motors. The major source of emissions from compressor engines is combustion products in the exhaust gas. These emissions include carbon monoxide, hydrocarbons, nitrogen oxides, aldehydes and ammonia. Sulfur oxides may also be present, depending on the sulfur content of the fossil fuel used.

Sweetening of distillates is accomplished by the conversion of mercaptans to alkyl disulfides in the presence of a catalyst. The extracted distillate is then contacted with air to convert mercaptans to disulfides. After oxidation, the distillate is settled, inhibitors are added, and the distillate is sent to storage. The major emission problem is hydrocarbons from contact between the distillate product and air in the "air blowing" step.

Fugitive emission sources are generally defined as volatile organic compound (VOC) emission sources not associated with a specific process but scattered throughout the refinery. Fugitive VOC emissions are attributable to the evaporation of leaked or spilled petroleum liquids and gases. Valves, flanges, pump and compressor seals, process drains, cooling towers, and oil/water separators are sources of fugitive emissions.

According to the US-EPA[59], for these sources, a very high correlation has been found between mass emission rates and the type of stream service in which the sources are employed. Except for compressed gases, streams are classified into one of three stream groups, (1) gas/vapor streams, (2) light liquid/two phase streams, and (3) kerosene and heavier liquid streams. Gasses passing through compressors are classified as either hydrogen or hydrocarbon service. Sources in gas/vapor stream service have higher emission rates then those in heavier stream service. It seems that valves, because of their number and relatively high emission factor, are the major emission source among the source types.

Storage vessels containing organic liquids can be found in the petroleum producing and refining, petrochemical and chemical manufacturing and bulk and transfer operations. Organic liquids in the petroleum industry, usually called petroleum liquids, generally are mixtures of hydrocarbons having dissimilar true vapor pressures (for example, gasoline and crude oil). Clearly, emissions from organic liquids in storage depend upon the tank type and operation activities as well as upon physical conditions of temperature and barometric pressure. Generally speaking, evaporative emissions from storage tanks can be classified as breathing, working and standing storage losses.

[59] Assessment of Atmospheric Emissions from Petroleum Refining, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1980.

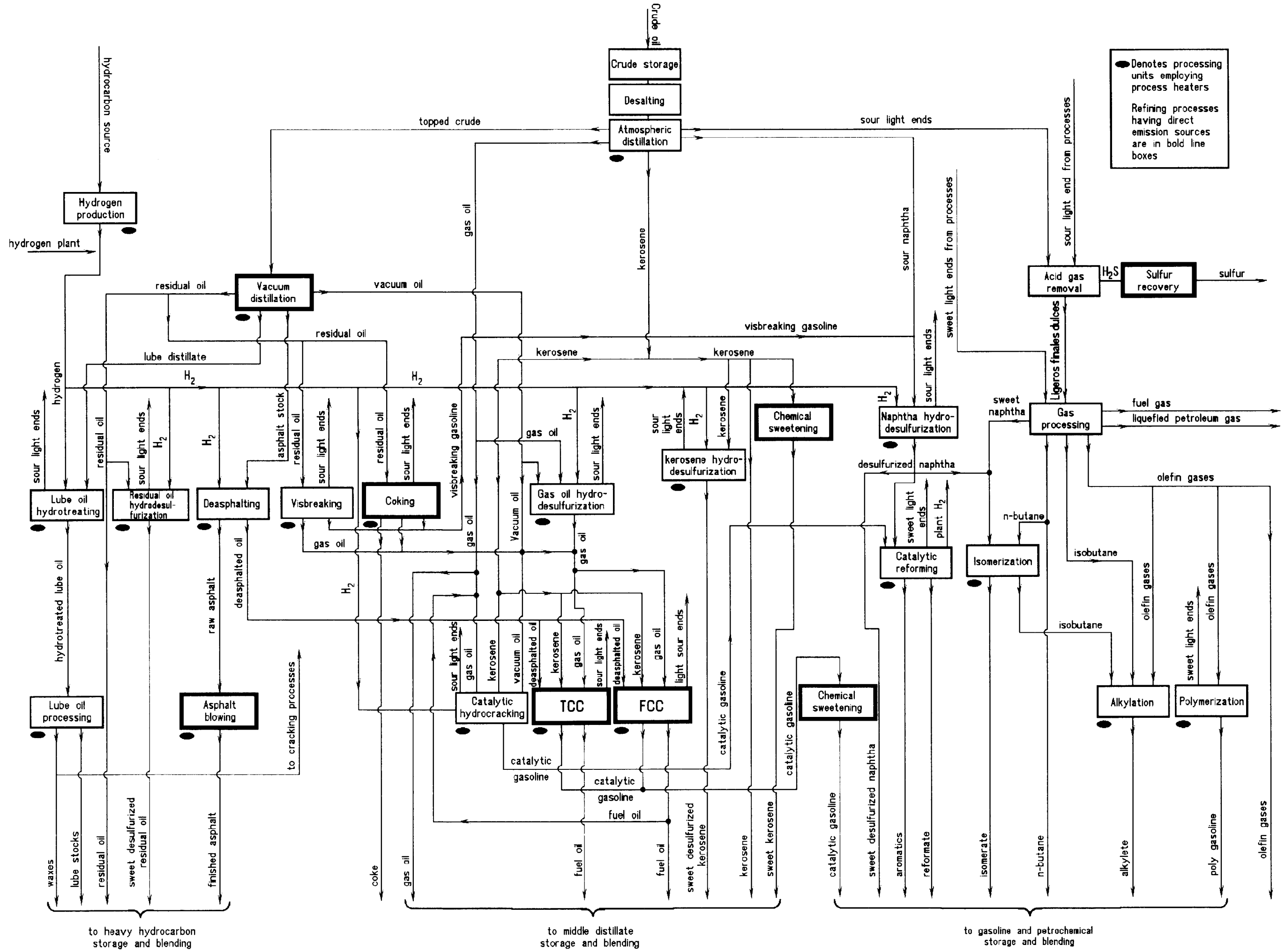

Figure D.1 Schematic representation of a petroleum refinery.

Transfer operations of oil and oil products are sources of evaporative emissions. Most refinery feedstock and products are transported by pipeline; trucks, rail tank cars and marine vessels transport some. They are transferred to and from these transport vehicles in the refinery tank farm area by specialized pumps and piping systems.

All refineries employ some form of wastewater treatment so water effluents can safely be returned to the environment or reused in the refinery. The design of wastewater treatment plants is complicated by the diversity of refinery pollutants, including oil, phenols, sulfides, dissolved solids, and toxic chemicals. Although the wastewater treatment processes employed in refineries vary greatly, they generally include neutralizers, oil/water separators, settling chambers, clarifiers, dissolved air flotation systems, coagulators, aerated lagoons, and activated sludge ponds. Most of the wastewater treatment occurs in open ponds and tanks. The main components of atmospheric emissions from wastewater treatment plants are fugitive VOC and dissolved gases that evaporate from the surface of wastewater residing in open process drains, wastewater separators, and wastewater ponds. Treatment processes that involve extensive contact of wastewater and air, such as aeration ponds and dissolved air flotation have an even greater potential for atmospheric emissions.

Finally, cooling towers are used extensively in refinery cooling water systems to transfer waste heat from cooling water to the atmosphere. In the cooling tower, warm cooling water returning from refinery processes is contacted with air by cascading through packing. Therefore, atmospheric emissions from the cooling tower consist of fugitive VOC and gases stripped from the cooling water as the air and water come into contact. These contaminants enter the cooling water system from leaking heat exchangers and condensers. Although the predominant contaminant in cooling water is VOC, dissolved gases such as hydrogen sulfide and ammonia may also be found.

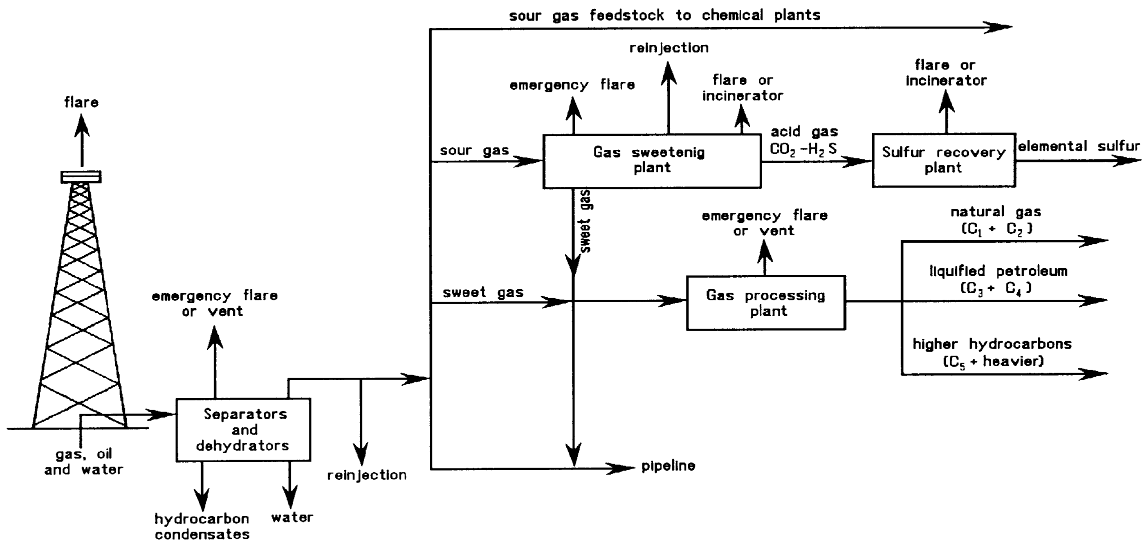

Figure D.2 Generalized flow diagram of the natural gas industry.

I-6.5. Gas processing (gas plants)

Natural gas from high-pressure wells is usually passed through field separators to remove hydrocarbon condensates and water at the well. Natural gasoline, butane, and propane are usually present in the gas, and gas-processing plants are required for the recovery of these liquefiable constituents (Figure D.2). Natural gas is considered "sour" if hydrogen sulfide is present in amounts greater than 0.25 grain per 100 standard cubic feet. The hydrogen sulfide (H_2S) must be removed (through the sweetening gas process) before the gas can be utilized. If H_2S is present, the gas is usually sweetened by absorption of the H_2S in an amine solution (Figure D.3). However, there are some other processes for gas sweetening, such as carbonate processes, solid bed absorbents, and physical absorption methods are employed.

The major emission sources in the natural gas processing industry are compressor engines and acid gas wastes from gas sweetening plants. Engines in the natural gas industry are used primarily to power compressors used for pipeline transportation, field gathering (collecting gas from the wells), underground storage, and gas processing plant applications. Pipeline engines are concentrated in the major gas producing regions and along the major gas pipelines. Both reciprocating engines and gas turbines are utilized, but the trend has been toward use of large gas turbines. Gas turbines emit considerably fewer pollutants than do reciprocating engines; however, it seems that reciprocating engines are generally more efficient in their use of fuel.

The primary pollutant of concern is NO_X, which readily forms in the high temperature, pressure, and excess air environment found in natural gas fired compressor engines. Lesser amounts of carbon monoxide and hydrocarbons are emitted, although for each unit of natural gas burned, compressor engines (particularly reciprocating engines) emit significantly more of these pollutants than do external combustion boilers. Sulfur oxides emissions are proportional to the sulfur content in the fuel and will usually be quite low because of the negligible sulfur content of most pipeline gas.

The major variables affecting NO_X emissions from compressor engines include the air fuel ratio, engine load (defined as the ratio of the operating horsepower divided by the rated horsepower), intake (manifold) air temperature, and absolute humidity. In general, NO_X emissions increase with increasing load and intake air temperature and decrease with increasing absolute humidity and air fuel ratio. Because NO_X is the primary pollutant of significance emitted from pipeline compressor engines, control measures to date have directed mainly at limiting NOx emissions. For gas turbines, the most effective method of controlling NO_X emissions is the injection of water into the combustion chamber.

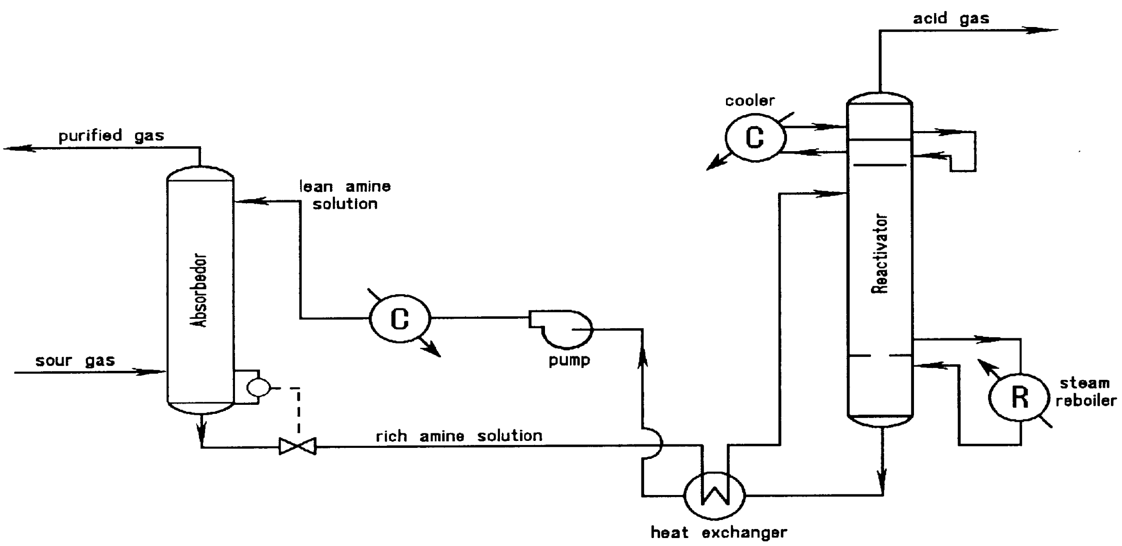

Figure D.3 Flow diagram of the amine process for gas sweetening.

Steam injection can provide a second method, however it is necessary to produce the steam. Also, exhaust gas re-circulation can reduce the NO_X emissions but they must be cooled before re-injection. Some of these methods are also applicable, in some extension, to reciprocating gas-fired engines. It seems that the most effective NO_X control measures for reciprocating gas-fired engines are those that change the air-fuel ratio. Thus, changes in the engine torque, speed, intake air temperature, etc., which in turn increase the air-fuel ratio may all result in lower NO_X emissions. Besides NO_X emission there are contributions of CO, hydrocarbons, sulfur dioxide and particulate.

The amine type method for sweetening natural gas is shown in Figure D.3. The recovered hydrogen sulfide gas stream may be (1) vented, (2) flared in waste gas flares or modern smokeless flares, (3) incinerated, or (4) utilized in the production of elemental sulfur or other commercial products. If the recovered H_2S gas stream is not to be utilized as a feedstock for commercial applications, the gas is usually passed to a tail gas incinerator in which the H_2S is oxidized to sulfur dioxide and then passed to the atmosphere via a stack. Emissions will only result from gas sweetening plants if the acid waste gas from the amine process is flared or incinerated. Most often, the acid waste gas is used as a feedstock in nearby sulfur recovery or sulfuric acid plants.

Appendix V.

MAJOR EMISSIONS

Table E.1 CO_2 emissions per year

Year	Base case	Limited combined cycle	Limited gas supply	Forced nuclear	Increased reliability	Decreased reliability
	without control million ton CO_2	without control million ton CO_2	without control million ton CO_2	without control million ton CO_2	without control million ton CO_2	without control million ton CO_2
1998	81.983	81.983	81.983	81.983	81.983	81.983
1999	87.135	87.135	87.135	87.135	87.135	87.135
2000	90.428	90.428	90.428	90.428	90.428	90.428
2001	90.306	90.306	90.306	90.306	90.306	90.306
2002	91.331	91.331	91.331	91.331	91.331	91.331
2003	93.131	93.131	93.131	93.131	93.131	93.131
2004	95.175	95.175	95.175	95.175	95.175	95.175
2005	96.180	96.180	96.180	96.180	96.180	96.180
2006	99.500	99.500	99.500	99.500	99.500	99.500
2007	100.952	100.952	100.952	100.952	100.952	100.952
2008	101.425	101.425	101.425	101.425	101.425	101.425
2009	104.672	107.219	104.672	104.672	104.672	104.672
2010	109.267	112.977	110.350	109.267	109.267	109.267
2011	114.346	119.149	120.472	114.346	114.346	114.346
2012	120.617	125.707	131.145	116.439	119.683	120.617
2013	126.502	132.841	142.436	122.255	125.611	126.502
2014	132.415	140.000	153.722	128.176	131.463	132.415
2015	137.048	148.448	166.277	133.776	136.296	137.995
2016	143.389	156.593	178.441	139.267	141.870	143.389
2017	147.790	165.983	191.932	143.685	146.470	148.528
2018	154.098	175.517	205.602	150.060	152.313	154.753
2019	160.109	185.169	219.220	156.690	158.872	161.421
2020	166.379	195.472	233.622	162.949	165.832	167.574
2021	173.037	206.122	246.236	169.624	172.541	174.206
2022	180.563	217.174	261.315	176.570	180.059	181.086
2023	187.432	229.011	277.159	183.921	187.475	188.414
2024	195.520	241.287	293.370	191.961	195.159	196.515

Table E.2 SO_X emissions per year

Year	Base case	Limited combined cycle	Limited gas supply	Forced nuclear	Increased reliability	Decreased reliability
	with control million ton SOx	with control million ton SOx	with control million ton SOx	with control million ton SOx	with control million ton SOx	with control million ton SOx
1998	1.538	1.538	1.538	1.538	1.538	1.538
1999	1.600	1.600	1.600	1.600	1.600	1.600
2000	1.588	1.588	1.588	1.588	1.588	1.588
2001	1.398	1.398	1.398	1.398	1.398	1.398
2002	1.261	1.261	1.261	1.261	1.261	1.261
2003	1.203	1.203	1.203	1.203	1.203	1.203
2004	1.119	1.119	1.119	1.119	1.119	1.119
2005	0.969	0.969	0.969	0.969	0.969	0.969
2006	0.942	0.942	0.942	0.942	0.942	0.942
2007	0.784	0.784	0.784	0.784	0.784	0.784
2008	0.635	0.635	0.635	0.635	0.635	0.635
2009	0.557	0.675	0.557	0.557	0.557	0.557
2010	0.534	0.705	0.581	0.534	0.534	0.534
2011	0.524	0.744	0.804	0.524	0.524	0.524
2012	0.553	0.790	0.937	0.537	0.515	0.553
2013	0.569	0.865	0.884	0.547	0.533	0.569
2014	0.573	0.784	0.817	0.553	0.533	0.573
2015	0.527	0.701	0.748	0.548	0.493	0.569
2016	0.541	0.620	0.675	0.524	0.471	0.541
2017	0.450	0.551	0.619	0.432	0.383	0.486
2018	0.440	0.512	0.595	0.425	0.348	0.472
2019	0.404	0.506	0.595	0.421	0.340	0.471
2020	0.371	0.483	0.586	0.388	0.343	0.433
2021	0.348	0.468	0.591	0.366	0.324	0.409
2022	0.360	0.462	0.595	0.347	0.334	0.386
2023	0.327	0.447	0.588	0.339	0.329	0.376
2024	0.344	0.444	0.590	0.353	0.327	0.395

Table E.3 NO_X emissions per year

Year	Base case	Limited combined cycle	Limited gas supply	Forced nuclear	Increased reliability	Decreased reliability
	with control million ton NOx	with control million ton NOx	with control million ton NOx	with control million ton NOx	with control million ton NOx	with control million ton NOx
1998	0.221	0.221	0.221	0.221	0.221	0.221
1999	0.233	0.233	0.233	0.233	0.233	0.233
2000	0.237	0.237	0.237	0.237	0.237	0.237
2001	0.235	0.235	0.235	0.235	0.235	0.235
2002	0.248	0.248	0.248	0.248	0.248	0.248
2003	0.249	0.249	0.249	0.249	0.249	0.249
2004	0.248	0.248	0.248	0.248	0.248	0.248
2005	0.245	0.245	0.245	0.245	0.245	0.245
2006	0.249	0.249	0.249	0.249	0.249	0.249
2007	0.244	0.244	0.244	0.244	0.244	0.244
2008	0.238	0.238	0.238	0.238	0.238	0.238
2009	0.238	0.245	0.238	0.238	0.238	0.238
2010	0.242	0.254	0.246	0.242	0.242	0.242
2011	0.247	0.262	0.266	0.247	0.247	0.247
2012	0.258	0.272	0.297	0.251	0.253	0.258
2013	0.263	0.281	0.346	0.257	0.260	0.263
2014	0.271	0.305	0.397	0.264	0.267	0.271
2015	0.271	0.335	0.454	0.268	0.268	0.274
2016	0.279	0.364	0.511	0.273	0.274	0.279
2017	0.281	0.399	0.573	0.275	0.277	0.283
2018	0.288	0.431	0.632	0.283	0.284	0.291
2019	0.295	0.460	0.688	0.291	0.292	0.299
2020	0.302	0.494	0.750	0.298	0.300	0.305
2021	0.310	0.529	0.800	0.306	0.308	0.313
2022	0.320	0.565	0.863	0.314	0.318	0.321
2023	0.327	0.605	0.931	0.323	0.327	0.330
2024	0.338	0.646	0.999	0.334	0.336	0.341

Table E.4 Particle emissions per year

Year	Base case	Limited combined cycle	Limited gas supply	Forced nuclear	Increased reliability	Decreased reliability
	with control million ton particle	with control million ton particle	with control million ton particle	with control million ton particle	with control million ton particle	with control million ton particle
1998	0.094	0.094	0.094	0.094	0.094	0.094
1999	0.098	0.098	0.098	0.098	0.098	0.098
2000	0.097	0.097	0.097	0.097	0.097	0.097
2001	0.084	0.084	0.084	0.084	0.084	0.084
2002	0.072	0.072	0.072	0.072	0.072	0.072
2003	0.068	0.068	0.068	0.068	0.068	0.068
2004	0.063	0.063	0.063	0.063	0.063	0.063
2005	0.054	0.054	0.054	0.054	0.054	0.054
2006	0.052	0.052	0.052	0.052	0.052	0.052
2007	0.043	0.043	0.043	0.043	0.043	0.043
2008	0.034	0.034	0.034	0.034	0.034	0.034
2009	0.029	0.036	0.029	0.029	0.029	0.029
2010	0.028	0.038	0.030	0.028	0.028	0.028
2011	0.027	0.040	0.044	0.027	0.027	0.027
2012	0.029	0.043	0.052	0.028	0.027	0.029
2013	0.030	0.048	0.051	0.028	0.028	0.030
2014	0.030	0.043	0.048	0.029	0.028	0.030
2015	0.027	0.039	0.046	0.029	0.025	0.030
2016	0.028	0.035	0.043	0.027	0.024	0.028
2017	0.023	0.032	0.041	0.022	0.019	0.025
2018	0.022	0.030	0.041	0.021	0.017	0.024
2019	0.020	0.031	0.043	0.021	0.016	0.024
2020	0.018	0.030	0.044	0.019	0.016	0.022
2021	0.017	0.030	0.045	0.018	0.015	0.020
2022	0.017	0.030	0.047	0.016	0.016	0.019
2023	0.015	0.030	0.048	0.016	0.015	0.018
2024	0.016	0.031	0.050	0.017	0.015	0.019

Appendix VI.

NUCLEAR CHAIN COST

Table F.1 Nuclear chain cost calculation using IAEA benchmarking methodology

Reactor and operation parameters: N655					
Reactor		**Fuel**			
Reactor Type	BWR	Core Inventory, MTU	80.274	Enrichment, % U-235	3.92
Electric Power, MW(e)	689.18	Burn up, MWd/MTU	45290	Tails, % U-235	0.25
Thermal Power, MW(t)	2027	Equilibrium reload, MTU	20.22		
Efficiency (h), %/100	0.34				
Operation		**Lead and lag times**		**Process losses**	
Cycle length, days	547.5	Cycle Start, yr	0.00	Conversion	1.005
Refueling time, days	40	Uranium, yr	0.00	Fabrication	1
Load Factor, %	0.89	Conv/UF_6, yr	-1.42		
EFPD, days	452	Enrichment, yr	-0.75		
Cap Factor, %/100	0.82	Fabrication, yr	-0.33		
Residence time, yr	6.0	Net cost backd, yr	6.0		
Unit prices		**Economic**			
Uranium, \$/lb U_3O_8	\$0.00	Discount rate, %/100	0.1		
Uranium esc, \$/lb U_3O_8	\$0.00	Esc rate U, %/100	0		
Conversion, \$/kg U	\$50.00	No. of years	1		
Enrichment, \$/SWU	\$100.00				
Fabrication, \$/kg U	\$250.00				
Net Cost, \$/kg U	\$500.00				
Energy calculation		**Results:**			
Thermal energy, MWtd	915545	PW Factor	0.75288		
Electric energy (fuel), TW·h	7.471	PWElec, TW·h	5.625		
Electric energy (FPD), TW·h	7.471				
Concept	**Amount**	**Cost, m\$**	**PW, m\$**	**Mills/kWh**	
Uranium, lb U_3O_8	419899	0.000	0.000	0.0000	
Conversion, MTU	160.711	8.036	9.197	1.6352	
Enrichment, SWU x 10^3	114.357	11.436	12.283	2.1838	
Fabrication, MTU	20.22	5.054	5.217	0.9275	
Net cost, MTU	20.22	10.108	5.729	1.0186	
Total		34.633	32.426	5.7651	

I-7. Nuclear fuel chain cost

This Appendix presents data and results for the nuclear fuel chain cost calculation under the current operation conditions of the Laguna Verde's plant. Table F.1 shows the resulting costs and they were obtained using the methodology described by the IAEA in the benchmarking of extended burn up study[60]. In this study several countries tested their calculations from a given set of plant and fuel parameters.

The calculation is made for the batch of the equilibrium cycle designed for the energy generation of a 18 month cycle with 40 days of refueling included as planned unavailability in the capacity factor of the plant. Also included are the lead/lag times for payment of the different materials and services of the nuclear fuel cycle and the process losses in each step of the fuel chain.
From this data and the current market prices for each step, a cost for each step is included and discounted at 10 percent discount rate. This value is then divided by the discounted value of the energy generated during the irradiation cycle. Note that the residence time of the batch in the reactor is 6 years or 4 irradiation cycles of 18 months each cycle. During this time the energy produced in each cycle should be discounted to the loading date of the equilibrium batch. In this simplified calculation we are assuming that the energy is produced at a midpoint of the residence time and then discounted to the loading date of the batch. This is consistent with the methodology described by the IAEA. The meaning of \$0 cost for uranium component reflects CFE policy to buy UF_6 instead of uranium concentrates, so the cost of both uranium and conversion is included in the conversion step.

[60] "Water Reactor Fuel Extended Burn up Study", IAEA Technical Report Series No. 343, Vienna, 1992.

Appendix VII.

SENSITIVITY ANALYSIS FOR ALTERNATIVE CASES

I-8. Description of the alternative (sensitivity) cases

From the whole list of cases to be considered in the present study, some of them are not commented in Chapter 6. In this section, the following alternatives will be discussed:

B_2: Forced nuclear introduction;

E_2: Decreased discount rate;

F_1: Increased power system reliability;

F_2: Decreased power system reliability; and,

F_3: Decreased reserve margin.

In order to compare the main results of those alternatives with the Base Case, Table G.1 shows the additional capacity and total costs (investment and production costs) until 2024.

Table G.1 Optimal solution until 2024

Optimal solution until 2024 US dollars of 1998									
		Nuclear 1356	Dual 350	Combined cycle 546	Gas turbine 179	HIDA	HIDB	Total capacity MW	Total cost million US$
	Base Case	0	0	118	6	3	2	68041	54419
B_2	Forced nuclear By year 2012	1	0	115	9	3	2	68296	54975
E_2	Discount rate 8% Instead 10%	0	0	118	8	3	2	68399	66505
F_1	Increased reliability 1 day/year; ENSC = 13 US$/kWh	0	0	119	15	3	2	70198	54520
F_2	Decreased reliability 5 days/year, ENSC = 0.55 US$/kWh	0	0	116	4	3	2	66591	54359
F_3	Decreased reserve margin ENSC = 0.25 US$/kWh	0	0	113	4	3	2	64953	54288

In Alternative B_2, one forced nuclear power plant of 1 356 MW is assumed with the objective to see possible non-economic advantages of an additional nuclear power plant and its impacts on the system cost. It may be noted that the inclusion of a new nuclear power plant in 2012 reduces the number of combined cycle units of 546 MW, *i.e.,* in this alternative the number of new combined cycle units is 115 compared with 118 in the Base Case whereas the capacity of gas turbines units of 179 MW is increased with 3 new gas turbine units. The total discounted cost (investment and system operation cost) increases to 54.975 billion dollars, because the investment increases to 10.272 and the operation expenditures (fuel and O&M cost) have a slight decrease to 44.702 billion dollars.

In Alternative E_2, the impact of the discount rate of 8% is not significant in the type and number of units to be installed, which are almost the same as in the Base Case - this alternative requires 8 gas turbine units of 179 MW instead of 6 units. Due to the discount rate of 8% the total discounted cost increases substantially to 66.505 billion dollars, 11.604 for investment and 54.900 for operation costs.

In order to increase the system reliability, Alternative F_1 assumes the LOLP of 1 day per year instead of 3 days per year in the Base Case. The cost of ENS equals 13 US$/kWh instead of 1.5 US$/kWh with the objective to obtain the required LOLP of 1 day per year. In this condition the system requires 119 combined cycle units of 546 MW (64 974 MW) and 115 gas turbine units of 179 MW (2 685 MW). The total discounted cost has just a slight increase to 54.520 billion dollars, 9.682 for investment and 44.837 for operation expenditures.

On the other hand, to decrease the system reliability in Alternative F_2, a LOLP of 5 days per year, instead of 3 days per year, as in the Base Case, is assumed. In this case, the cost of ENS equals to 0.55 US$/kWh instead of 1.5 US$/kWh. The optimal solution requires 116 combined cycle units of 546 MW (63 336 MW) and 4 gas turbine units of 179 MW (716 MW). The total cost decreases to 54.359 billion dollars, because the investment decreases to 9.468 while the operation and maintenance expenditures increases very little to 44.890 million dollars.

Finally in Alternative F_3, it is assumed that the cost of ENS is 0.25 US$/kWh in order to decrease the reserve margin of the power system. The system requires the installation of 113 combined cycle units of 546 MW (61 698 MW) and 4 gas turbine units of 179 MW (716 MW). Compared with the Base Case, the system reserve margin obtained in this alternative is lower.

Appendix VIII.

ENERGY SYSTEM DIVERSITY

I-9. Measuring energy system diversity

Once the most economic expansion scenario is defined, it should be examined in terms of diversity. Is diversity good for the system or is it more economic to leave the system as it is? To answer this question one should first determine the value of diversity and verify if it is positive or negative. There are two objectives that are satisfied by a scenario with higher diversity than the Base Case, that is:

(1) There is a coverage in case of interruption of supply, like a oil shock or a future gas shock; and,
(2) There is a coverage to the high "volatility" of oil or gas prices in the future.

In the first case, the cost to the economy should be evaluated in terms of the energy non-served and how fast we can change to other technological options. The second case has been studied by means of the "portfolio theory" and the conclusions are that diversity is good if the resulting covariance is not positive for the optimal mix. It simply reflects the idea of not putting all the eggs in one basket. However if all energy prices will change following the same pattern, then diversity is not useful, unless we have domestic energy resources that we can develop soon. In this latter case diversity with non-fossil fuels such as nuclear or renewable is better than diversity with fossil fuels.

Once the diversity analysis is made, it has to be decided if the government should internalize this security externality, if the price paid to obtain this diversity is lower than the cost of these major disruptions *e.g.* it will be like the payment of some kind of insurance. After this study the government has to look at other options like the possibility of establishing stocks, the diversification of suppliers and supply contracts and plant/fuel substitutions. The cost of these options should be compared. Also the level of risk should be evaluated and defined as a policy to be followed by the country. In cases of a high degree of competition in the energy market the cost may be lower, but the level of risk will increase.

A diversity Index developed by Stirling was used to describe the diversity of the scenarios and was included in the DAM analysis. The Stirling Index was used as an indicator of energy supply diversity. The Index was calculated for the mix of the capacity resulting in the end year of the study for the selected expansions using the formula:

$$H = -\sum_i p_i \ln(p_i),$$

where p_i represents the proportion of installed capacity i in the total supply mix.

There are two problems in using this Index, one is to decide if we want to use it in terms of energy supplied by different fuels or in terms of installed capacity in the electric system. We believe that the Index will better express diversity in terms of capacity because the energy supplied depends on other factors like the level of demand, the power dispatching and the margin of reserve; while installed capacity will define the true mix of the system. The other problem is how to determine the weight or value of one unit of diversity expressed by this Index, in order to introduce it in the DAM study.

To solve the first problem we decided to calculate, for each scenario, the Index for the installed capacity at the end of the study (2024) and then refine it by studying the possibilities of further diversification of the scenario by changing the fuel to the plant and/or changing the source of supply. For example a coal or a gas plant can be changed to oil, or an oil plant can be changed to gas. Also the source of oil or gas can be domestic or imported. Coal will always be imported since there are not coal reserves in the country. Each time a possibility of change (or internal diversification) was identified, the capacity was duplicated and a new "potential" Index was calculated for each scenario.

One way to calculate the cost of diversity is to compare two scenarios optimized by DECADES. In the Base Case scenario we can increase the levelized price of gas up to the price p*, a price at which the Stirling Index will change as shown as in Figure H.1.

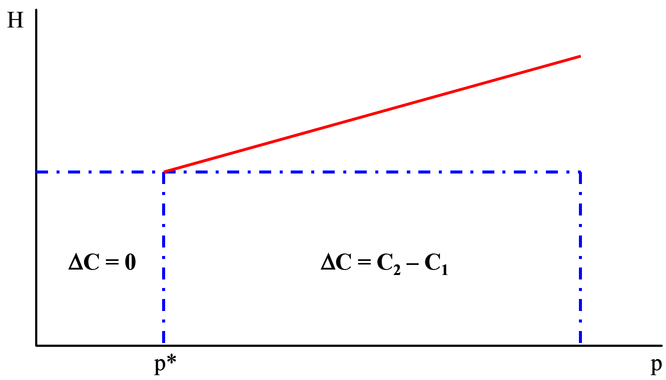

Figure H.1 Stirling Index as a function of the gas price.

In this figure, the Stirling Index will not change below price p*, which means that the Base Case optimization will not change and the value of diversity ΔC is equal to zero. Above p* the Base Case optimization will change giving us a higher Stirling Index H. In this case we can find a positive value of diversity ΔC, which is equal to the difference in the cost of the expansion of the optimized Base Case with a higher Stirling Index (C_1) and the cost of a fixed Base Case, with a lower Stirling Index (C_2), in which no optimization of the expansion was conducted. If we divide the ΔC by the increment in the Stirling Index ΔH, we can calculate the value of one unit of this Index to be used in the DAM analysis.

However it is clear that the value of diversity will be different for different increments in the gas price, maybe not a linear function as shown in Figure H.1, but a step function with some small increments. In this case it has been suggested to apply a decreasing probability to the different gas scenarios and calculate a most probable value for the diversity. Another factor to take into account is the time in which the expansion can change itself when the gas prices change and the impact of a financial coverage, stocks, domestic production and other ways to alleviate future gas price volatility.

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ACRONYMS AND ABBREVIATIONS

ABWR	Advanced Boiling Water Reactor
AP42	Compilation of Air Pollutant Emission Factors
Ar	Argon
Ba	Barium
BALANCE	Energy Supply and Demand Analysis Module of ENPEP
BWR	Boiling Water Reactor
C	Carbon
CC54	Natural gas combined cycle unit with a capacity of 546 MW
CCGT	Combined Cycle Gas Turbine
Ce	Cerium
CEEESA	Center for Energy, Environmental, and Economic Systems Analysis
CH4	Methane
CO	Carbon Monoxide
Co	Cobalt
CO2	Carbon Dioxide
CO2-biomass	Carbon Dioxide from biomass
COGEN	WASP Configuration Generator
COPAR	Costs and Parameters of Reference for the Formulation of Investment Projects in the Power Sector
Cr	Chromium
Cs	Cesium
CSDB	Country Specific Databases
Cu	Copper
DAM	Decision Analysis Module of ENPEP for Windows
DAM	Decision Analysis Module of DECADES for Windows
DECADES	Databases and MEthodologies for Comparative Assessment of Different Energy Sources for Electricity Generation
DECPAC	DECADES analytical software for analysis and comparison of costs and environmental burdens
DGSCA-UNAM	Dirección General de Servicios de Cómputo Académico-UNAM
DMS	Database Management System
DOE	U. S. Department of Energy
DYNPRO	WASP Dynamic Programming Optimization
EC	European Union
ENPEP	Energy and Power Evaluation Program

ENS	energy not served
FGD	flue gas desulphurization
FIXSYS	WASP fixed system description
FO	fuel oil
GDP	gross domestic product
GHG	greenhouse gasses
GTMax	Generation and Transmission Maximization Model
H	Stirling Index
H2S	Hydrogen sulfide
HCl	Hydrogen Chloride
HEIES	impacts database
HF	Hydrogen Fluoride
HLW	high level waste
I	Iodine
ICARUS	Investigating Costs and Reliability in Utility Systems
IIE	Electrical Research Institute
IMPACTS	Environmental Impact Module of ENPEP for Windows
IPCC	Intergovernmental Panel on Climate Change
IPPS	independent power producers
IS	interconnected system
Kr	Krypton
La	Lanthanum
LCC	limited combined cycle
LDC	load duration curve
LMLW	low/medium level waste
LNG	liquefied natural gas
LOAD	load module of ENPEP for Windows
LOADSY	WASP load system description
LOLP	loss of load probability
LPG	liquefied petroleum gas
LYFC	Light and Power Company for the Center
M	million (mega)
MACRO-E	macroeconomic module of ENPEP for Windows
MAED	model for analysis of energy demand
MBq	Mega Becquerel

MERSIM	WASP merge and simulate
Mn	Manganese
MODEMA	MOdelo de DEMAnda de Energía (Energy Demand Model)
N135	advanced boiling water reactor with a capacity of 1,356 MW
N2O	Nitrous Oxides
N655	Boiling water reactor with a capacity of 654 MW
Nb	Niobium
ND35	Dual fuel unit with desulphurization and a capacity of 350 MW
NES	National Electric System
NG	natural gas
NGI	National Interconnected Grid
NGL	Natural Gas Liquids
NH3	Ammonia
NMTOC	non-methane total organic compounds
NMVOC	non-methane volatile organic compounds
NOC	net overnight cost
NOM-085-ECOL-1994	Mexican standard that regulates smoke, total suspended particles, sulfur and nitrogen oxides from fixed sources that use fossil fuels
NOX	Nitrogen Oxides
NPV	net present value
NREL	National Renewable Energy Laboratory
NRS	national refinery system
O&M	Operation and Maintenance
OECD	Organization for Economic Cooperation and Development
Pb	Lead
PCVAL	PC-Valoragua
PEP	PEMEX-Exploration and Production
PGPB	PEMEX- Gas and Basic Petrochemicals
PIE	Productores Independientes de Electricidad (Electricity Independent Producers)
PM	particulate matter
ppm	parts per million
PPQ	PEMEX-Petrochemicals
PR	PEMEX-Refining
PUE-UNAM	Programa Universitario de Energía-UNAM
PV	Photovoltaic

REMERSIM	WASP Re-Merge and Simulate
REPROBAT	WASP Report Writer in a Batched Environment
RTDB	reference technology database
Ru	Ruthenium
Sb	Antimony
SENER	Ministry of Energy
SO2	Sulfur Dioxide
SOX	Sulfur Oxides
SPNRES	spinning reserve
Sr	Strontium
SWU	separative working units
T&D	transmission and distribution
T179	natural gas simple cycle unit with a capacity of 179 MW
TFC	total final energy consumption
TOC	total organic compounds
TPES	total primary energy supply
TRAN	transport data base for Mexico
TSP	total suspended particles
UED	useful energy demand
V	Vanadium
VALORAGUA	Hydro Simulation Model
VARSYS	WASP Variable System Description
VOC	Volatile Organic Compounds
WASP	Wien Automatic Planning Package
WFGD	Wet Flue Gas Desulphurization
Xe	Xenon
Zn	Zinc

UNITS OF MEASURE

% p.a.	per cent per year
$	US dollar
$/kW	US Dollars per kilowatt
$/MMbtu	US Dollars per million Btu
$/ MW·h	US Dollars per megawatt hour
ºC	degree Celsius
bcm	billion cubic meters
boe	barrel of oil equivalent
BTU	British Thermal Unit
cal/cm2	calorie per square centimeter
cbm	cubic meters
g	gram
GW	Gigawatt
GW·h	Gigawatt hour
kcal	kilocalorie
kcal/kg	kilocalorie per kilogram
kcal/ kW·h	kilocalorie per kilowatt hour
kg	kilogram
km	kilometer
km2	square kilometer
mth	month
MW(d)	Megawatt day
Mw(e)	Megawatt electric
kW(e)	kilowatt electric
kW·h	kilowatt hour
kW·h /m2	kilowatt hour per square meter
l	liter
J	Joule
h	hour
yr	year
m	meter
m/s	meter per second
m3	cubic meter
mm	millimeter

Mt	million metric tons
Mt/yr	million metric tons per year
Mtoe	million tons of oil equivalent
MJ	Megajoule
Mg	milligram
ng	nanogram
GJ	Gigajoule
MW	Megawatt
MW(e)	Megawatt electric
MW(th)	Megawatt thermal
PJ	Petajoules
ton	metric ton
t/yr	metric ton per year
toe	ton of oil equivalent
TJ	Terajoule
TW·h	Terawatt-hours
Watt/m2	Watt per square meter
Wh	Watt hour
kboe	1000 barrels of oil equivalent
kt	1000 tons
ktoe	1000 tons of oil equivalent
toe/US$1,000	ton of oil equivalent per 1,000 US Dollars
US$	US Dollars (all costs in this report are in constant US$2000)

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