ANL-07/10 VOL 2

Argonne NATIONAL LABORATORY

Poland Becoming a Member of the Global Nuclear Energy Partnership

Volume 2 – Appendices

Decision and Information Sciences Division

About Argonne National Laboratory
Argonne is a U.S. Department of Energy laboratory managed by UChicago Argonne, LLC under contract DE-AC02-06CH11357. The Laboratory's main facility is outside Chicago, at 9700 South Cass Avenue, Argonne, Illinois 60439. For information about Argonne, see www.anl.gov.

ANL-07/10 VOL 2

Poland Becoming a Member of the Global Nuclear Energy Partnership

Volume 2 – Appendices

by
V. Koritarov, G. Conzelmann, R.R. Cirillo, and S.M. Goldberg*
Decision and Information Sciences Division, Argonne National Laboratory
*Office of the Director, Argonne National Laboratory

work supported by
U.S. Department of Energy
Office of Nuclear Energy

March 2007

Study Participants

Vladimir Koritarov, Deputy Director, Center for Energy, Environmental, and Economic Systems Analysis, Decision and Information Sciences, Argonne National Laboratory

Guenter Conzelmann, Director, Center for Energy, Environmental, and Economic Systems Analysis, Decision and Information Sciences Division, Argonne National Laboratory

Richard R. Cirillo, Director, Decision and Information Sciences Division, Argonne National Laboratory

Stephen M. Goldberg, Assistant to the Director, Argonne National Laboratory

Technical Support:

Emily Storm, Co-op Student, Purdue University

Andrzej Kerner, Energy Market Agency Advisor

TABLE OF CONTENTS

Volume 1: Summary

Under Separate Cover

Volume 2: Appendices

TABLE OF CONTENTS (CONT.)

TABLES

TABLES (CONT.)

FIGURES

FIGURES (CONT.)

FIGURES (CONT.)

NOTATION

The following is a list of the abbreviations, acronyms, and units of measure used in this document. (Some acronyms and abbreviations used only in tables may be defined only in those tables.)

GENERAL ACRONYMS, ABBREVIATIONS, AND UNITS OF MEASURE

ABWR	Advanced boiling water reactor
AFBC	Atmospheric fluidized bed combustion
AFUDC	Allowance for funds used during construction
ALWR	Advanced light water reactor
ANL	Argonne National Laboratory
AP1000	Advanced pressurized water reactor
ARE	Energy Market Agency
BGK	Bank Gospodarstwa Krajowego
BWR	Boiling water reactor
CAS	Country assistance strategy
CENTREL	Coordinated power systems of Poland, the Czech Republic, Slovakia, and Hungary
CHP	High-efficiency cogeneration of heat and power
CO_2	Carbon dioxide
CONGEN	Configuration generator
CPN	Central Oil Distribution Company
DH	District heating
DHW	Domestic hot water
DR	Discount rate
DYNPRO	Dynamic Programming Optimization
EBRD	European Bank for Reconstruction and Development
EBSA	BOT Elektrownia Belchatow SA
EE	Energy efficiency
EMA	Energy Market Agency
EMCAS	Electricity Market Complex Adaptive System
ENS	Energy-not-served
EPR	European pressurized water reactor
EPRI	Electric Power Research Institute
ERO	Energy Regulatory Office
ESCO	Energy Service Company
EU	European Union
EUR	Banking code for euros (1 EUR [€] = $1.3152 USD [2/19/07])

FGD	Flue gas desulphurisation
FIXSYS	Fixed System Description
GEF	Global environment facility
GJ	Gigajoule equivalent to 1,000,000,000 joules
GNEP	Global Nuclear Energy Partnership
GWh	Gigawatt hour
HOB	Heat-only-boiler
IDC	Interest during construction
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IPS	Interconnected Power Systems of the Soviet Union and Warsaw Bloc countries
ISO	Independent system operator
kW	Kilowatt
LCOE	Levelized cost of electricity
LMP	Locational marginal price
LNG	Liquefied natural gas
LOADSY	Load System Description
MBtu	Thousand British thermal units
MERSIM	Merge and Simulate
MMBtu	Million British Thermal Units
MPEC	Municipal Thermal Energy Enterprise
MW	Megawatt
MWe	Megawatt electric
MWh	Megawatt-hour
NAEA	National Atomic Energy Agency
NEA	Nuclear Energy Agency
NGCC	Natural gas combined cycle
NPV	Net present value
O&M	Operation and maintenance
OECD	Organization for Economic Cooperation and Development
PAK	ZE Patnow Adamow Konin S.A.
PC	Pulverized coal
PFBC	Pressurized fluidized bed combustion
PHWR	Advanced CANDU reactor
PKN	Polski Koncern Naftowy
PLN	Polish Złoty (1 PLN = €0.256786 [2/19/07])

POE ESCO	Polish service company funding energy efficiency projects
POGC or PGNiG	State Polish Oil and Gas Company
PPGC	Polish Power Grid Company
P-S	Pump Storage
PSE	Polskie Sieci Eectroenergetyczne (Polish Power Grid company)
REMERSIM	Re-Merge and Simulate
REPROBAT	Report Writer of WASP in a Batched Environment
RTO	Regional transmission organizations
SETSO	South-East Europe Transmission System Operators
TSO	Transmission system operator
UCTE	Union for the Co-ordination of Transmission of Electricity
VARSYS	Variable System Description
VVER	Russian type of PWR reactor
WASP	Wien Automatic System Planning Package

APPENDIX 1
BACKGROUND INFORMATION ON POLAND

1.1 SUMMARY OF VISIT

The study team obtained firsthand onsite technical and economic data derived from discussions with officials with the Ministry of Economy, the Polish Power Grid Company, the Energy Market Agency (EMA), the Polish Transmission System Operator, and the National Atomic Energy Agency/Atomic Energy Institute.

- Ministry of Economy — The Ministry has a neutral stance regarding the development of nuclear power in Poland. One of its representatives stated that the Argonne National Laboratory report will be important input to the Government's decision-making process and that the private sector will largely have to provide the initiative and funding for the construction of new nuclear plants. In a subsequent communication to the Department of Energy, the Ministry of Economy reported that the study, "Poland's Energy Policy until the Year 2025," provides for the need to introduce nuclear power into the Polish power system around the year 2020. Startup of the first nuclear power plant before 2020 is not likely, since the duration of the investment process in the country — which hardly has any experience with projects of this scope — will take an estimated 10 years, and the social campaign for nuclear power generation preceding the construction process will take an estimated five years.

- Polish Power Grid Company (PSE S.A.) owns the transmission grid in Poland. The company is interested in investing in new nuclear plants as possible joint venture projects with other companies, i.e., in Lithuania.

- Poland's Energy Market Agency (EMA S.A. (ARE)) is a statistical entity that collects and publishes energy-related information for Poland. EMA S.A. reported that the construction of the first nuclear power plant in Poland was originally started in the 1980s (Zarnowiec location, VVER 4x440 MW), but was abandoned in 1990. The EMA S.A. study identified 2021 as a viable date for nuclear energy.

- Polish Transmission System Operator (TSO) is a member of the Union for the Coordination of Transmission of Electricity (UCTE). The UCTE is an association of transmission system operators in continental Europe that ensures reliable technical infrastructure for the common electricity market by means of an efficient and safe usage of synchronously operating power systems, i.e., providing a reliable market base by efficient and secure electric "power highways." PSE-Operator also has all necessary information on the dispatch operations. PSE-Operator was unbundled from the PSE S.A. on July 1, 2004 and formed as an autonomous power company subject to regulation by the President and Energy Regulatory Office. The TSO objective is to ensure transparent and equal conditions for all entities connected to or making use of the Polish transmission grid.

- National Atomic Energy Agency and Atomic Energy Institute (NAEA) — The president of NAEA provided an overview of the current status and prospects of nuclear power in Poland and the role of NAEA. “The Energy Policy for Poland until 2025” projects a 60% increase in electricity consumption in Poland over the next 20 years. According to the Energy Policy, about 7.5–8% of electricity production in 2021 is expected to come from nuclear power. NAEA regularly conducts public opinion surveys about nuclear power. NAEA supports the harmonization of the nuclear licensing system in Europe. The Polish government will not provide any funding for nuclear power projects, but may provide some loan guaranties.

Most of the data and information necessary to carry out this analysis were derived from the EMA statistics. In addition, PSE-Operator has the specific information for the modeling of the Polish transmission grid. The data collection effort for this analysis was lead by Dr. Andrzej Kerner, a member of Argonne’s project team providing technical assistance in Poland. Dr. Kerner has been affiliated with the EMA and has in-depth knowledge of the Polish energy system. He was also a key author of several energy studies for Poland, including the latest EMA analysis of the long-term capacity expansion options for Poland.

1.2 PUBLIC ACCEPTANCE

In the European Union (EU) — and elsewhere — all investment activities in the energy sector require public acceptance. These include transmission lines, oil or gas pipelines, wind farms, and nuclear projects. The directive on the assessment of environmental impacts states that the investor must submit appropriate information to the “concerned public,” and also enable the communities involved to express their opinions on a proposed project prior to the start of its implementation. This directive, adopted in 1985, was thoroughly amended in 1997. It is supported by other legal documents, in particular, by the Strategic Environmental Assessment Directive and the Aarhus Convention ratified by the European Council.

Following the government's decision on adopting the “Energy Policy for Poland up to 2025,” the discussion toward the development of nuclear power in Poland becomes more and more extended (the document adopted by the government envisions the start-up of the first Polish nuclear power plant by 2021–2022).

The document referred to above contains the following statement: “The necessary diversification of the primary energy sources and the need for the reduction of greenhouse gas emissions into the atmosphere justify the introduction of nuclear power into the national system. However, the implementation of this proposal requires public acceptance. The forecasts indicate that, in the second decade of the period under consideration, there will be the need for nuclear-generated electricity; thus – taking into account the investment cycle length — public debate on this issue must be initiated immediately."

1.2.1 Findings of the Survey Conducted by the National Atomic Energy Agency (NAEA)

- NAEA has completed a current and comprehensive survey of the public acceptance situation in Poland. This is the regulatory body that is legally in charge of educating and informing the public on nuclear issues. In the document, "Energy Policy for Poland up to 2025," adopted by the national government in 2005, the NAEA envisions the start-up of Poland's first nuclear plant around 2021, and, in taking account of the investment cycle length, notes that "public debate on the issue must be initiated immediately."

- The NAEA survey is a comprehensive set of questions on public opinion that has been conducted every two years since 1994. This is a valuable set of information that reveals not only current attitudes, but also their trends over time. The sample in the most recent of these surveys conducted in 2004 included 1,013 individuals, with most results having small statistical error margins of less than 3%. The next survey will be conducted at the end of 2006. The primary opinions investigated include the use of coal power, nuclear power, and energy materials emitting CO_2, construction of a local nuclear facility, use of radiation in various fields, and the concerns and grounds for objections to nuclear power.

- When asked, "In your opinion, should we seek a gradual reduction in the use of coal in electricity generation?," 59% of respondents replied either "definitely yes" or "rather yes," 20% responded "definitely no" or "rather no," and 20% responded "don't know." Thus, independent of the nuclear option, most people would like to see a reduction in coal use. (Demographically, the survey shows that men want to reduce coal use more than women, the younger people are slightly more receptive to the idea than older people, that people of higher education strongly prefer reduced use of coal, and that urban people also strongly prefer reduced use of coal.)

- Seventy-two percent of those surveyed were aware that carbon dioxide emissions are responsible for climate change and that its use should be restricted.

- Respondents were then asked whether nuclear power should be given special preferences similar to renewable energy sources since it does not emit CO_2 — 42% agreed, 35% disagreed, and the remainder abstained. Again, the survey found a higher acceptance in urban, educated, young, and male populations.

- Regarding the degree of consent for nuclear power, 2004 marked the first time since the survey was conducted that more individuals were for nuclear power than against it (42% to 38%). From 1996 until 2002, those for were 15–20% lower than those against, which indicates a recent strong positive shift in public opinion for nuclear power. This result will be even stronger if verified in the 2006 survey. (Again, urban, educated, young, and male populations prefer nuclear relative to their counterparts. Approximately 20% of Poles had no opinion on the issue in the recent survey, indicating the immediate progress that could be made from a well-designed educational initiative.)

1.3 PUBLIC FINANCING OPPORTUNITIES

Two potential organizations, the European Bank for Reconstruction and Development (EBRD) and the World Bank, have the necessary financial capital to support a new nuclear energy plant in Poland. The World Bank has not historically supported financing new nuclear energy projects; however, in a more constrained carbon environment, the World Bank may be more inclined to support a new nuclear energy project in Poland, which currently relies heavily on fossil-fired technologies. Below is a listing of energy projects currently supported by the EBRD and the World Bank.

1.3.1 The EBRD

The EBRD was established in 1991 when communism was crumbling in central and eastern Europe and ex-Soviet countries needed support to nurture a new private sector in a democratic environment. Today, the EBRD uses the tools of investment to help build market economies and democracies in 27 countries from central Europe to central Asia. The EBRD is the largest single investor in the region and mobilizes significant foreign direct investment beyond its own financing. It is owned by 60 countries and two intergovernmental institutions. But despite its public sector shareholders, it invests mainly in private enterprises, usually together with commercial partners. It provides project financing for banks, industries, and businesses, both new ventures and existing companies. It also works with publicly owned companies to support privatization, restructuring of state-owned firms, and improvement of municipal services. The Bank uses its close relationship with governments in the region to promote policies that will bolster the business environment.

The EBRD is financing the following energy projects in Poland:

1. The EBRD is lending BOT Elektrownia Bełchatów S.A, Europe's largest lignite-fired power plant, the Złoty equivalent of EUR (€) 125 million to build a state-of-the-art 833 megawatt generating unit at its main site in Bełchatów (near Łódź), in central Poland. The investment is part of an overall €1.7 billion modernization and environmental strategy being implemented by state-owned Bełchatów to bring it in line with Polish and European Union environmental standards. The program includes the modernization of existing

power units, additional flue gas desulphurization installations, and a new waste disposal system. The overall investment is being supported with €220 million in financing from the European Investment Bank, and €150 million from the Nordic Investment Bank. Two commercial banks, ING and Citibank, who together with EBRD play the role of the lead arrangers, will provide various facilities in the total amount of €604 million.

2. EBRD is investing up to €70 million of equity investment in Dolna Odra, in partnership with Endesa Europa S.L. (the Sponsor). Dolna Odra is the fifth largest power plant in Poland, consisting of three coal-fired power and heat plants of total generation capacity of 1,960 MW. Dolna Odra is the only large power plant in the north-west of Poland and, as such, has a particular importance for the security of the Polish power grid and serves as a back-up for the transmission system operator. The Company is a joint stock company wholly owned by the Polish Treasury, and is currently in the "…process of being privatised to Endesa of Spain."

3. EBRD is investing up to €540 million for construction of a new single 464 MW unit at the ZE Patnow Adamow Konin S.A. (PAK), a group of three lignite-fired power plants. The project will use supercritical boiler technology and is going to be implemented through a "turn-key" contract. The capital investment is the first stage of PAK's overall program of modernization and environmental upgrades. Since PAK provides about 13 % of the Polish electricity, the program is expected to significantly reduce emissions.

4. EBRD is investing up to €56 million to establish an Energy Service Company in Poland to be known as "ESCO International" to finance and implement small- and medium-sized energy efficiency projects.

1.3.2 The World Bank

Since Poland rejoined the World Bank in 1986, the Bank has supported the economic transformation efforts of successive Polish governments through policy dialogue, technical assistance related to project preparation, capacity building and institutional strengthening, and financing. The World Bank's mission in Poland has been to support the country's efforts to bring greater economic welfare to its people. The World Bank is helping the Government to move to a full market economy.

The World Bank is financing the following energy projects in Poland:

1. The World Bank is investing US$78 million for the Krakow Energy Efficiency Project. This project aims to improve the efficiency of the city's district heating (DH) systems, decrease heat energy consumption by improving energy efficiency at the end-user level, and develop knowledge-based mechanisms to finance energy efficiency projects.

2. The World Bank is investing US$65 million in the proposed Global Environment Facility (GEF) energy efficiency project. The project has the following three components: (1) a partial guarantee facility with US$5.7 million in reserves will be established with GEF funds as a risk-sharing mechanism that will provide commercial banks partial coverage of risk exposure against loans made for energy efficiency projects of buildings throughout Poland; (2) support of US$6.67 million in bundled energy efficiency projects in the Krakow region; and (3) technical assistance.

3. The World Bank is investing US$186 million in the 2002 Country Assistance Strategy (CAS) for Poland. The objective of this project is to enhance private sector-led growth, and employment creation through enterprise restructuring; support for coal sector reform was included as a priority within that pillar in the CAS. The Hard Coal Mine Closure Project will directly support the physical closure and environmental reclamation of excess coal mine capacity.

APPENDIX 2
CURRENT STATUS OF ENERGY MARKETS IN POLAND

2.1 STRUCTURE OF THE ELECTRICITY POWER SECTOR

The Energy Law of 1997 began the process to restructure Poland's electric power sector into three subsystems — generation, transmission, and distribution — with the goal of full restructuring. The country has about 35 electric-generation power plants, with both public and private owners. Plans call for reducing the number of generating companies and privatizing power generation. The transmission grid assets are owned by the state Polish Power Grid Company (PPGC) or Polskie Sieci Eectroenergetyczne (PSE). PSE is the largest energy company in Poland and is a party to a number of long-term power contracts that were signed in the period 1994-1998. In order to separate energy trade from transmission operations, a new autonomous power company PSE-Operator was formed in July 2004. While PSE still owns the transmission assets, they are now leased out to the PSE-Operator, which functions as Polish transmission system operator. PSE-Operator is subject to regulation by the President and Energy Regulatory Office with the main objective to ensure transparent and equal conditions for all entities connected to or making use of the Polish transmission grid. At present, the power market in Poland consists of the following:

- Active power market,
- Technical market, and
- Financial market.

The active power market comprises the bilateral contracts market and the balancing market. The technical market represents the market for ancillary services, while the financial market deals with the trade of financial contracts for electricity supply. About 20 distribution companies currently operate in Poland and provide electricity to their consumers on a regional basis. They can purchase their electricity needs either directly from producers or at the power market.

2.1.1 Status of Deregulation

The Ordinance of the Minister of Economy (on the schedule for acquisition of rights to use transmission services by individual groups of customers) provides for opening of the Polish power market to progressively smaller customers, i.e.,

- Customers with total annual purchase of electricity of more than 10 GWh acquired that right after 1 January 2002,
- Customers with total annual purchase of electricity of more than 1 GWh acquired that right after 1 January 2004, and

- Others who acquired that right after 1 January 2006.

2.1.2 Regulator

The Energy Regulatory Office (ERO), whose President is appointed by the Prime Minister for a five-year term, is responsible for granting licenses, approving tariffs, and settling disputes. There are detailed guidelines for tariff settlements and setting principles for connection to the grid and its financing. New regulations have drastically reduced the "connection fees."

2.1.3 Competition in Generation

An authorization (licensing) procedure is used. The President of the ERO may issue licenses for new generation capacity on the basis of the following criteria: technical and financial capabilities, location of facility, professional qualifications of employees, state energy policy, and public interest.

2.1.4 Tariff Setting

The ERO has released generators and electricity traders from the obligation to have their tariffs approved by the regulator (ERO) once they have proved that they are operating under competitive conditions. Transmission and distribution companies are obliged to submit their tariffs for review and approval by the ERO.

2.2 STRUCTURE OF THE OIL AND GAS MARKET

The hydrocarbon sector comprises companies that are wholly owned by the State Polish Oil and Gas Company (POGC or PGNiG). POGC is responsible for exploration, development, and operation of oil deposits, and for domestic and foreign trade of crude oil and its derivatives. POGC also ensures the production and the distribution of gas. Since 1996, POGC has been wholly owned by the Public Treasury. In August 2002, the government announced the adoption of the privatization program for POGC, which began during 2003. At the end of the privatization process, POGC will separate its activities into several companies: one for gas exploration and extraction, others for the distribution, and finally one company in charge of marketing. As of January 2003, distribution and retail trade in gas are conducted by six distribution companies, separated from the structures of POGC/PGNiG S.A. The two main producers and distributors of oil products merged in May 1999 to form Polski Koncern Naftowy (PKN). PKN is the result of the fusion of the Central Oil Distribution Company (CPN), the national company of service stations and distribution that supplied 40% of the Polish fuel market (with a network of 2,000 service stations out of 6,800), and the Plock refinery; PKN now accounts for 70% of Poland's production of petroleum products. The privatization of PKN started in November 1999 with the sale of 30% of its capital and continued in June 2000 with the sale of an additional 30%. In the refining sector, the privatization started in August 2001 with the sale of 75% of the capital of the refinery of Gdansk to the British company Rotch. In summary, some tangible progress in restructuring and privatization has been achieved in the oil sector.

There has been less progress in restructuring the gas sector and in implementing the strategy for privatization of the gas sector.

2.3 STRUCTURE OF THE COAL MARKET

The situation in the coal sector is characterized by continued restructuring. The level of debt is still very significant and is estimated at about 20 billion Złoty (PLN). Reforming of the sector is carried out on the basis of the program “Reform of the Coal-mining in Poland in the years 1998–2020.” A further program deals with restructuring and privatization of mines. The Coal Corporation, a monopolistic State structure that managed the coal industry until 1990, was replaced by a State-owned financial company, the State Agency for Coal.

Current private-sector coal operations include the following (the last three are small, independent mines):

- Katowicki Holding Weglow SA (9 mines),
- Kompania Weglowa SA,
- Jastrzebska Spolka Weglowa SA (5 mines),
- Spolka Restrukturyzacij Kopaln,
- Lubelski WEgiel Bogdanska SA,
- KWK Budryk SA, and
- Sobieski-Jaworzno.

APPENDIX 3
METHODOLOGY, ASSUMPTIONS, AND RESULTS OF THE SCREENING ANALYSIS

3.1 INTRODUCTION

The screening analysis is frequently used to determine the basic economic competitiveness of different generating technologies. The approach consists of calculating the annualized cost of electricity generation as a function of unit utilization level or capacity factor. The total generation costs expressed in U.S. dollars per kilowatt-hour are calculated as a sum of fixed and variable cost components. The fixed costs are independent of unit utilization level and consist of annualized capital costs and fixed operation and maintenance (O&M) costs. The variable costs are changing with the capacity factor and consist of fuel costs and variable O&M costs. The screening curves for several technology options can be plotted on the same graph to determine which ones are the most economical options at different utilization levels. Usually the capital-intensive technologies, such as baseload coal and nuclear plants, are the most economical options at higher utilization levels while generating technologies with low fixed costs (such as peaking units) are more economical at lower capacity factors.

Frequently, in cases with a large number of possible candidate technologies, the screening analysis is performed to eliminate those alternatives that are obviously not competitive, thus deriving a smaller set of candidate technologies for further evaluation. The screening curve analysis is an approximate method and is not a substitute for a thorough analysis. One of the main limitations of the screening curve analysis is that it does not consider the role of the project in the system and, therefore, does not include some of the important aspects that affect project operation, such as:

- Existing system capacity,
- Unit availability (forced and planned outages),
- Unit dispatch factors (e.g., minimum load and spinning reserve),
- System reliability requirements, and
- Dynamic factors changing over a unit's lifetime (e.g., load growth and economic trends).

The above factors can be properly assessed only with a system-wide analysis.

3.2 ASSUMPTIONS

There are several nuclear technologies that could be considered as candidates for possible future implementation in Poland. The EMA study[1] has selected the EPR 1,500 MW nuclear unit to represent a generic nuclear candidate for the long-term generating system expansion analysis. There are several reactor types of this size that are either presently available on the market or will be commercially available in the next 10 years or so. These are mostly advanced reactor types and include the following technologies:

- Advanced light water reactor (ALWR),
- European pressurized water reactor (EPR),
- Boiling water reactor (BWR),
- Advanced boiling water reactor (ABWR),
- Advanced CANDU reactor (PHWR), and
- Advanced VVER reactor (Russian type of PWR reactor).

Since it is also currently available on the market and has garnered the most interest within the European Union, the EPR technology was selected to be a representative generic nuclear candidate for the screening analysis. The EPR dataset was based on the information available from the IEA/NEA.[2] Since this analysis considers the potential implementation of nuclear power in a country that has not had any history of nuclear energy, the study team assumed an extended construction period of seven years. The allowance for funds used during construction (AFUDC) in units of percent contribution to fixed costs was estimated at 16.11%, as determined from the Wien Automatic System Planning Package (WASP) User's Manual for a discount rate of 5%.

The EPR will be competing primarily against the fossil-based technologies. The EMA study considered a number of advanced fossil-based candidate technologies for the long term expansion of the Polish power system, such as:

- Supercritical pulverized coal (PC),
- Pressurized fluidized bed combustion (PFBC),
- Atmospheric fluidized bed combustion (AFBC),
- Integrated gasification combined cycle (IGCC), and
- Natural gas combined cycle (NGCC).

---

[1] Jacek Marecki and Miroslaw Duda, "Why There is a Necessity to Build Nuclear Power Plants in Poland," NPPP 2006, Warszawa 2006.

[2] OECD report "Projected Costs of Generating Electricity — 2005 Update," published by the IEA. Available at http://www.iea.org/Textbase/publications/free_new_Desc.asp?PUBS_ID=1472.

The technical and economic characteristics of these technologies are based largely on the IEA/NEA OECD report, except for the fuel and O&M costs, which were adjusted for conditions in Poland. The main parameters of the nuclear and fossil candidate technologies compared in the analysis are summarized in Table 3.1.

TABLE 3.1 Technical and Economic Characteristics of Candidate Technologies (in U.S. Dollars)

	Nuclear	Lignite		Coal			Natural Gas
Candidate Technology	**EPR**	**PC**	**AFBC**	**PC**	**IGCC**	**PFBC**	**NGCC**
Net generating capacity (MW)	1,500	500	150	400	300	150	300
Overnight construction cost ($/kW)	1,895	1,280	1,100	1,160	1,450	1,240	590
Construction period (years)	7	4	4	4	4	4	2
AFUDC (%)	16.11	8.85	8.85	8.85	8.85	8.85	4.31
Total plant cost ($/kW)	2,200	1,393	1,197	1,263	1,578	1,350	615
Fixed O&M costs ($/kW-yr)	42.29	30.	30.	25.2	51.96	35.04	13.44
Variable O&M costs ($/MWh)	0.49	2.0	2.0	1.82	1.62	1.92	0.5
Unit net efficiency (%)	37.0	41.5	41.7	43.0	45.0	43.0	58.0
Fuel cost ($/GJ)	0.53[3]	1.66	1.59	2.19	2.19	2.19	3.98
Equivalent Forced Outage Rate (%)	4	3	10	9	5	5	4
Maintenance Time (days/year)	30	40	42	42	42	42	20
Availability (%)	88	86	80	81	84	84	91
Economic plant life (years)	40	40	40	40	40	40	30

3.3 RESULTS OF THE SCREENING ANALYSIS

The fossil-based technologies were compared against the representative nuclear candidate, the EPR. The analysis was carried out for the base year 2003, using the fuel prices expressed in constant 2003 U.S. dollars, and a discount rate of 5% for the annualization of capital costs. From the screening curves shown in Figures 3.1 through 3.3, it appears that the nuclear technology is the most economical option for capacity factors of 80% and higher.

The capital-intensive nuclear technology is very sensitive to the choice of discount rate. If a higher discount rate of 10% is used, the less-capital intensive NGCC candidate option becomes more favorable and shows as the most economical option up to a capacity factor of about 88%.

[3] The nuclear fuel costs typically represent 12–15% of the total cost of electricity produced by nuclear plants. Since uranium ore has to be processed and enriched in order to be used as nuclear fuel, the cost of uranium typically accounts for only a small fraction of the total cost of producing electricity from nuclear power plants. Therefore, even a large increase in the uranium price has a relatively small effect on the costs to produce nuclear electricity.

In this case, the AFBC technology is the most economical option for capacity factors of 88% and higher.

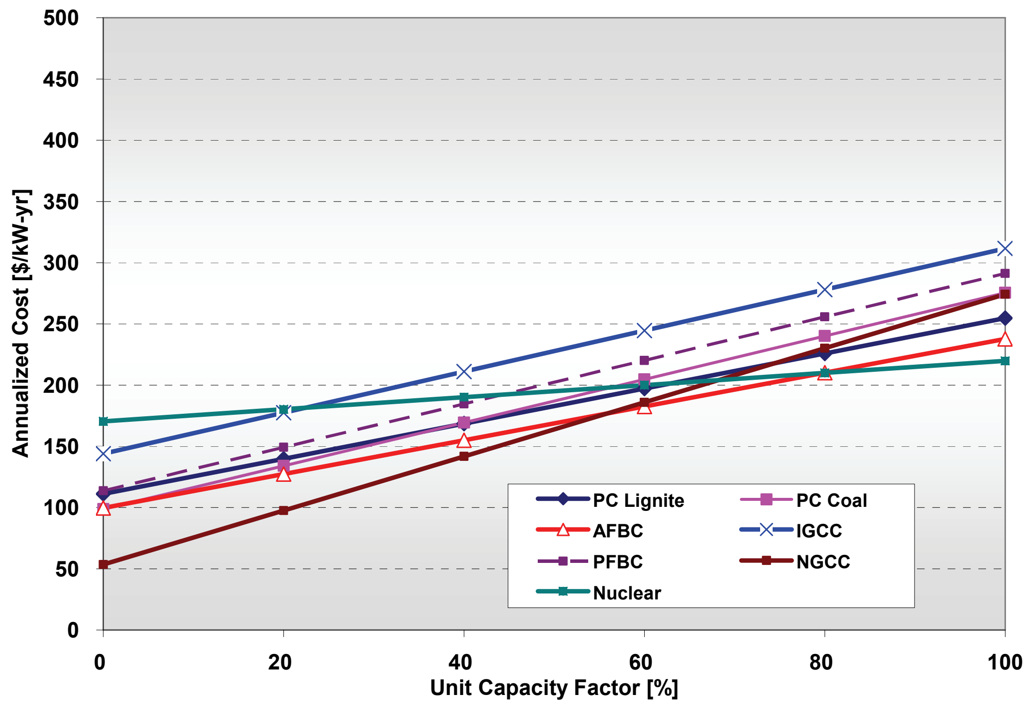

FIGURE 3.1 Screening Curves for 2003 Fuel Prices and 5% Discount Rate (in U.S. Dollars)

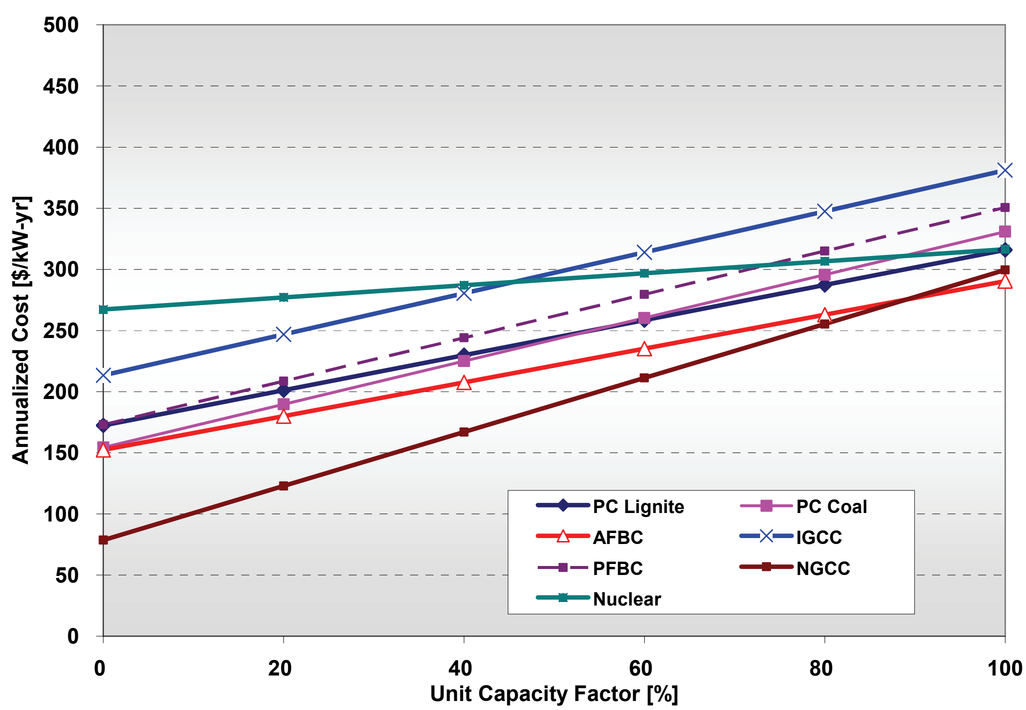

FIGURE 3.2 Screening Curves for 2003 Fuel Prices and 10% Discount Rate (in U.S. Dollars)

If the cost of CO_2 emission allowances is taken into account, it affects primarily the lignite- and coal-fired technologies, while the gas-fired NGCC is less affected because of lower carbon emissions. The nuclear technologies do not emit any CO_2 emissions during their operation; therefore, they are not affected by the CO_2 allowance cost. There is a market for CO_2 emission trading in Europe and, at the beginning of 2006, the prices were as high as $40 per ton of CO_2. The current prices are significantly lower. A screening curve analysis was conducted using a CO_2 allowance cost of $15 per ton. Even this relatively low value of CO_2, has a significant impact on the economic competitiveness of fossil-based technologies. The results show that the NGCC candidate is the most economical option for capacity factors of up to 55%, while the nuclear candidate is the most economical option for higher capacity factors.

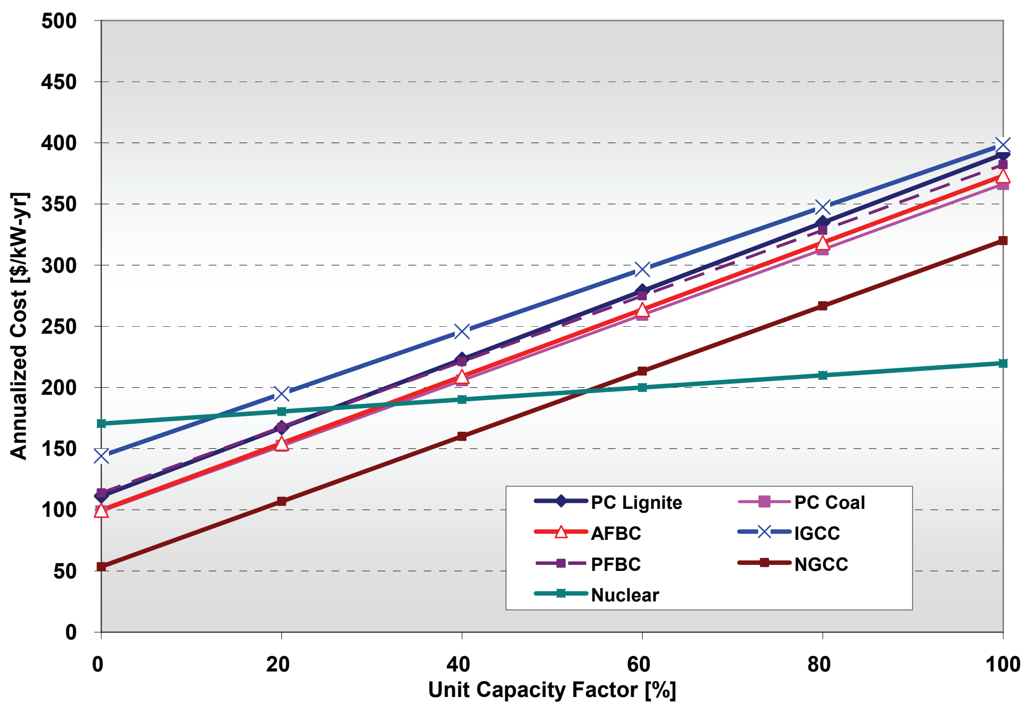

FIGURE 3.3 Screening Curves for 2003 Fuel Prices, DR 5%, and CO_2 Cost of $15/ton (in U.S. Dollars)

A screening curve analysis was also performed using the expected fuel prices in 2021, which, for this analysis, is estimated to be the in-service year for the first nuclear power plant in Poland. The projection for fuel prices in 2021 was developed using the World Energy Outlook 2005 forecast (Table 3.2). The OECD steam coal import price was used to project future prices of coal, while the European import price was used for the projection of natural gas prices. No real price escalation was used for the prices of nuclear fuel and lignite.

TABLE 3.2 World Energy Outlook 2005: Reference Case Fossil-Fuel Price Assumptions (in U.S. Dollars)

Type of Import	2004	2010	2020	2030
European imports of natural gas ($/MMBtu)[4]	4.20	5.00	5.20	5.60
OECD steam coal imports ($/ton)	55	49	50	51

The screening curve analysis in Figure 3.4 shows that for the level of expected fuel prices in 2021, the NGCC unit becomes less competitive and it is the lowest-cost option only for capacity factors of less than 30%. Between 30% and 80%, the AFBC candidate is the most economical, while the nuclear candidate is still the lowest cost option for capacity factors higher than 80%.

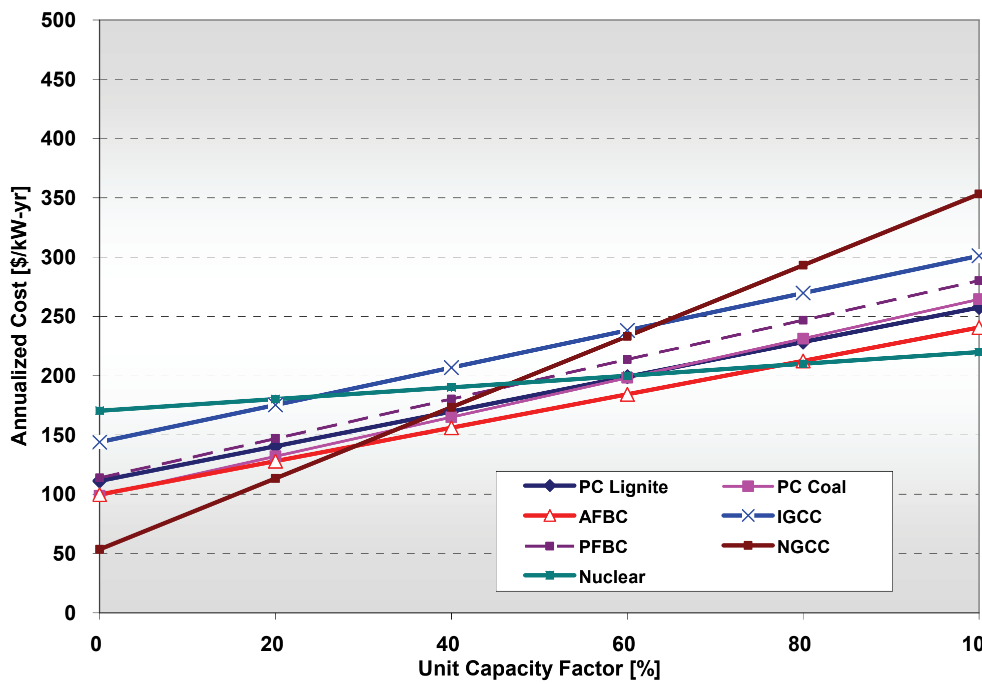

FIGURE 3.4 Screening Curves for 2021 Fuel Prices and 5% Discount Rate (in U.S. Dollars)

The case shown in Figure 3.4 didn't take into account the cost of CO_2 emission allowances. If a cost of $15 per ton of CO_2 (in 2003 U.S. dollars) is assumed, the screening curve analysis in Figure 3.5 shows that the nuclear technology becomes very favorable and is the most economical option for capacity factors of 40% and higher. The NGCC candidate is the lowest cost option for utilization factors of less than 40%.

[4] The study team used the 2005 World Energy Outlook to determine the projected price of natural gas; it is expected to rise to $5.20–5.60 per million British Thermal Units (MMBtu) in the 2020–2030 time frame (or about 25 percent above current prices); if geopolitical tensions rise between Russia and its Central and Eastern European customers, natural gas prices could rise more significantly, such prices for natural gas would make NGCCs economically uncompetitive.

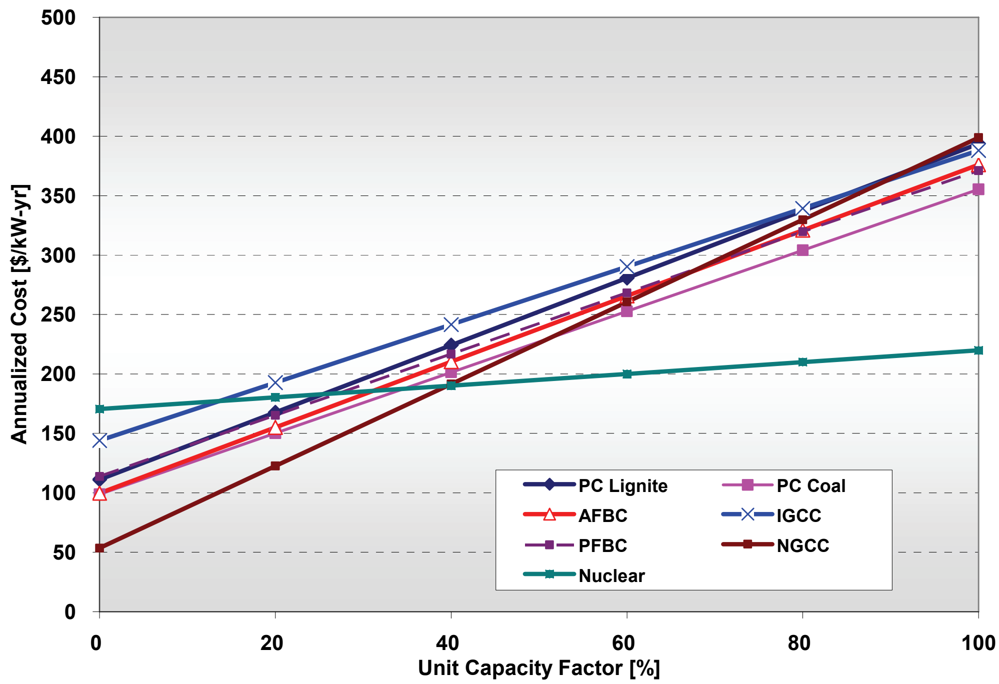

FIGURE 3.5 Screening Curves for 2021 Fuel Prices, 5% Discount Rate, and CO_2 Cost of $15/ton (in U.S. Dollars)

Even with a discount rate of 10%, the nuclear technology remains very competitive and is the most economical option for capacity factors of about 65% and higher, as shown in Figure 3.6.

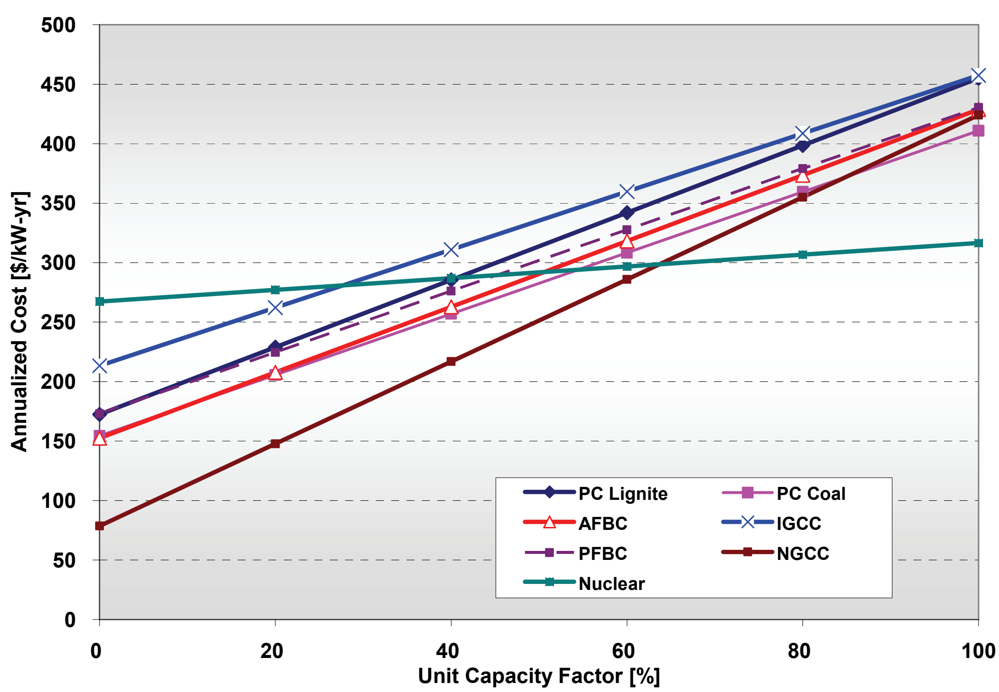

FIGURE 3.6 Screening Curves for 2021 Fuel Prices, 10% Discount Rate, and CO_2 Cost of $15/ton (in U.S. Dollars)

APPENDIX 4
METHODOLOGY, ASSUMPTIONS, AND RESULTS OF THE LCOE ANALYSIS

4.1 INTRODUCTION

The financial levelized cost analysis is a more detailed approach than the screening analysis. The financial levelized cost analysis provides a more detailed calculation of unit generating costs, as well as a number of financial ratios and parameters that allow for more detailed evaluation of the proposed candidate projects. The pre-tax levelized cost of electricity (LCOE) model calculates LCOE as the constant real price of electricity ($/MWh) that provides a net present value (NPV) equal to the NPV of all capital and operating costs over the economic lifetime of the plant. The pre-tax LCOE model contains the following four LCOE cost components:

- Annualized capital costs,
- Fixed O&M costs,
- Variable O&M costs, and
- Fuel costs.

While this model incorporates the basic LCOE components, it does not consider certain items, such as interest payments, depreciation, and taxes. Many LCOE estimates are calculated before taxes, so this model certainly provides for a basic economic comparison of different candidate technologies.

4.2 ASSUMPTIONS

The same technical and economic parameters were used for the LCOE analysis as were used for the screening analysis.

The pre-tax levelized cost analysis was conducted using the same methodology as in the OECD/NEA IEA report "Projected Costs of Generating Electricity — 2005 Update." In addition to the 5% and 10% discount rates that were used in the OECD report, the analysis was also performed for a discount rate of 8%. All costs are expressed in constant 2003 dollars. The levelized costs were calculated over the economic lifetime of each of the candidates. Finally, the EPR was selected as the reference nuclear plant because of the level of interest in that design in the EU (e.g., a 1,500-MW unit is currently being built at the Olkiluoto site in Finland).

4.3 RESULTS

The before-tax LCOE analysis was carried out for two levels of fuel prices corresponding to the years 2003 and 2015. The World Energy Outlook 2005 reference case forecast was used to determine the level of fuel prices in 2015 for different coal- and natural gas-fired candidate technologies. No real price escalation was used for the prices of nuclear fuel and lignite.

4.3.1 LCOE Results, 2003 Fuel Prices, No Carbon Cost

The before-tax LCOE results obtained for the candidate generating technologies for different discount rates and fuel prices in 2003 are presented in Table 4.1 and Figure 4.1.

TABLE 4.1 Pre-Tax LCOE for 2003 Fuel Prices (in U.S. Dollars)

Discount Rate (%)	EPR Nuclear (1500 MW)	PC Coal (400 MW)	IGCC Coal (300 MW)	PFBC Coal (150 MW)	PC Lignite (500 MW)	AFBC Lignite (150 MW)	NGCC Nat. Gas (300 MW)
5	29.74	33.27	39.68	36.28	31.49	29.32	31.91
8	37.04	37.56	45.44	41.15	36.34	33.48	33.74
10	42.29	40.64	49.59	44.65	39.82	36.48	35.08

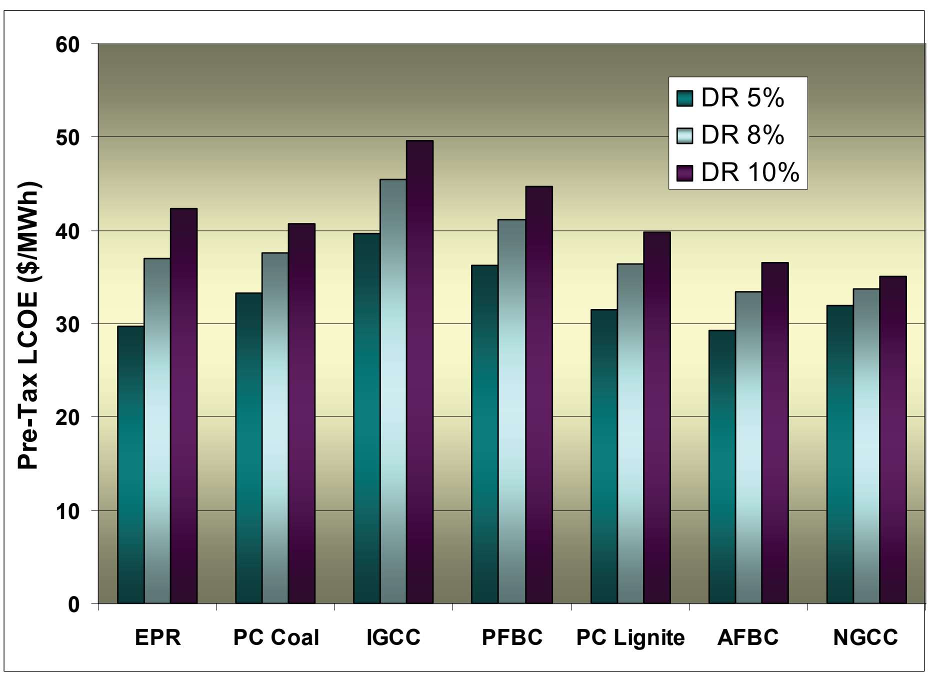

FIGURE 4.1 Pre-Tax LCOE for 2003 Fuel Prices (in U.S. Dollars)

The results show that for a 5% discount rate, the EPR nuclear and the AFBC lignite-fired candidate technologies are the lowest cost options, with levelized costs of \$29.74/MWh and \$29.32/MWh, respectively. The nuclear candidate is rather sensitive to higher discount rate values and its LCOE increases to \$42.29/MWh for a 10% discount rate. However, this is still lower than the LCOE of IGCC and PFBC candidates, which are the highest cost options for all three discount rates. It should be noted that in all analyzed cases the levelized cost of the nuclear candidate includes the decommissioning and waste fee costs.

The capital-intensive candidate technologies (i.e., nuclear and coal) are highly sensitive to the discount rate that is used for the present value calculations. On the other hand, technologies that are less capital intensive (i.e., NGCC) are not so sensitive to the discount rate, but are rather sensitive to fuel costs. The relative shares of different cost components in the levelized costs of the NGCC candidates are illustrated in Figure 4.2. The share of the capital cost component for the NGCC candidate is about 20%, while the fuel cost component represents more than 70% of the total levelized cost, for the two discount rates.

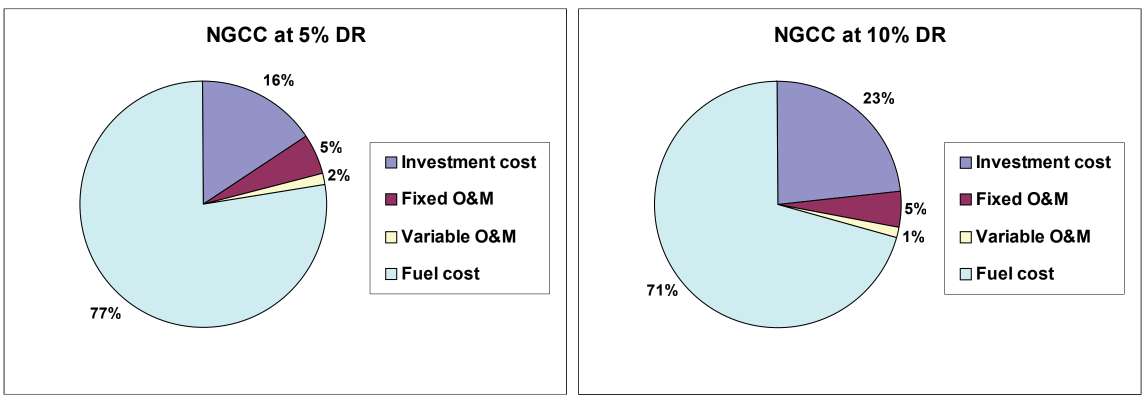

FIGURE 4.2 LCOE Cost Components for NGCC at 5% and 10% Discount Rates

A comparison of the relative shares of different cost components in the total pre-tax LCOE of different candidate technologies is presented in the Table 4.2 and illustrated in Figures 4.3 through 4.5. The results are in 2003 dollars, for the level of fuel prices in 2003 and for discount rates of 5%, 8%, and 10%.

TABLE 4.2 Breakdown of Pre-tax LCOE by Component for 2003 Fuel Prices (in U.S. Dollars)

LCOE ($/MWh)	EPR Nuclear 1500 MW	PC Coal 400 MW	IGCC Coal 300 MW	PFBC Coal 150 MW	PC Lignite 500 MW	AFBC Lignite 150 MW	NGCC Nat. Gas 300 MW
Discount Rate 5%							
Investment cost	16.63	9.77	13.13	11.09	11.03	9.48	4.50
Fixed O&M	5.49	3.35	7.41	4.94	4.08	4.08	1.69
Variable O&M	0.49	1.82	1.62	1.92	2.00	2.00	0.50
Fuel cost	5.13	18.34	17.52	18.34	14.38	13.76	24.70
Dec.& waste cost	2.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	29.74	33.27	39.68	36.28	31.49	29.32	31.91
Discount Rate 8%							
Investment cost	23.94	14.06	18.89	15.95	15.88	13.65	6.47
Fixed O&M	5.49	3.35	7.41	4.94	4.08	4.08	1.69
Variable O&M	0.49	1.82	1.62	1.92	2.00	2.00	0.50
Fuel cost	5.13	18.34	17.52	18.34	14.38	13.76	24.70
Dec.& waste cost	2.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	37.04	37.56	45.44	41.15	36.34	33.48	33.74
Discount Rate 10%							
Investment cost	29.19	17.14	23.03	19.45	19.36	16.64	7.89
Fixed O&M	5.49	3.35	7.41	4.94	4.08	4.08	1.69
Variable O&M	0.49	1.82	1.62	1.92	2.00	2.00	0.50
Fuel cost	5.13	18.34	17.52	18.34	14.38	13.76	24.70
Dec.& waste cost	2.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	42.29	40.64	49.59	44.65	39.82	36.48	35.08

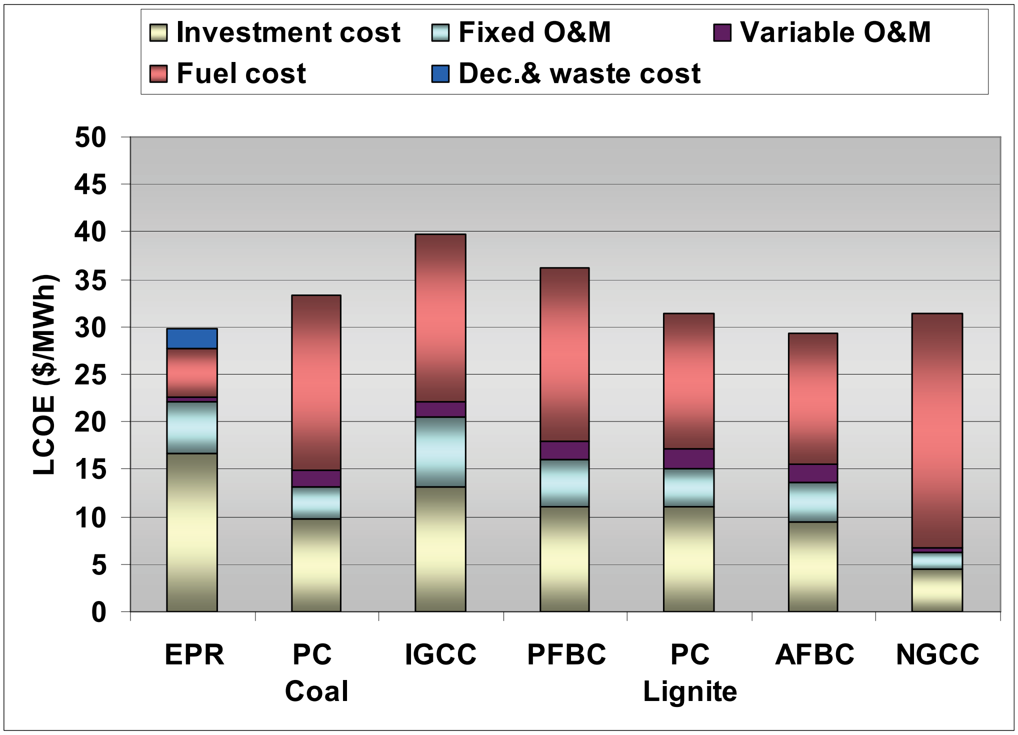

FIGURE 4.3 Pre-tax LCOE by Component for 2003 Fuel Prices and 5% Discount Rate (in U.S. Dollars)

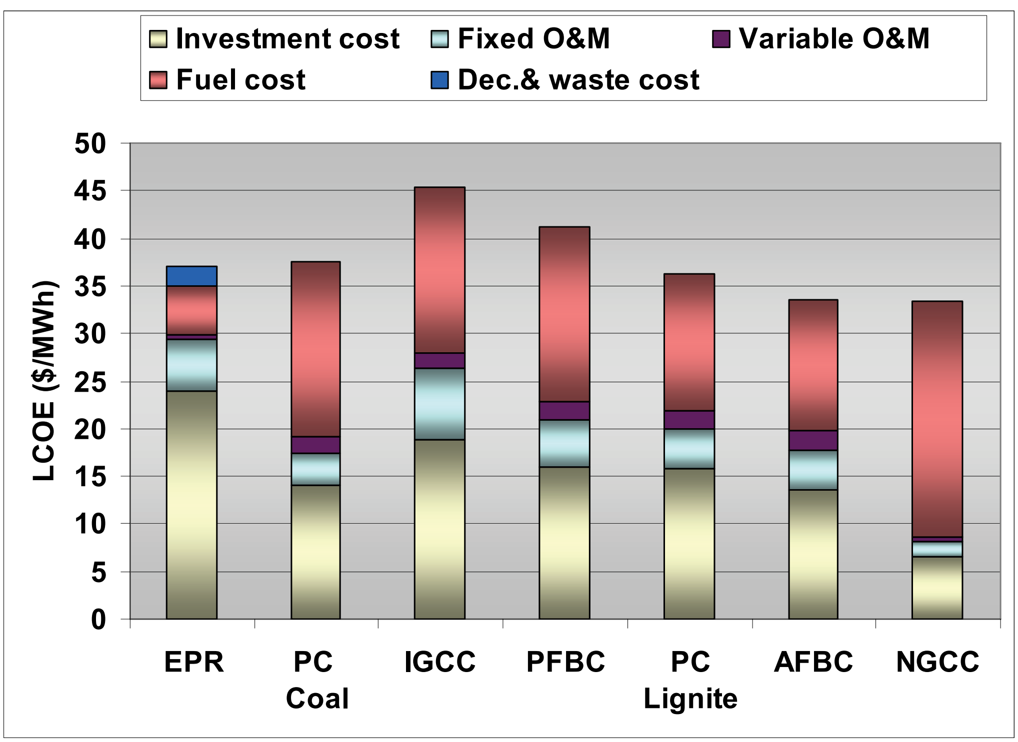

FIGURE 4.4 Pre-tax LCOE by Component for 2003 Fuel Prices and 8% Discount Rate (in U.S. Dollars)

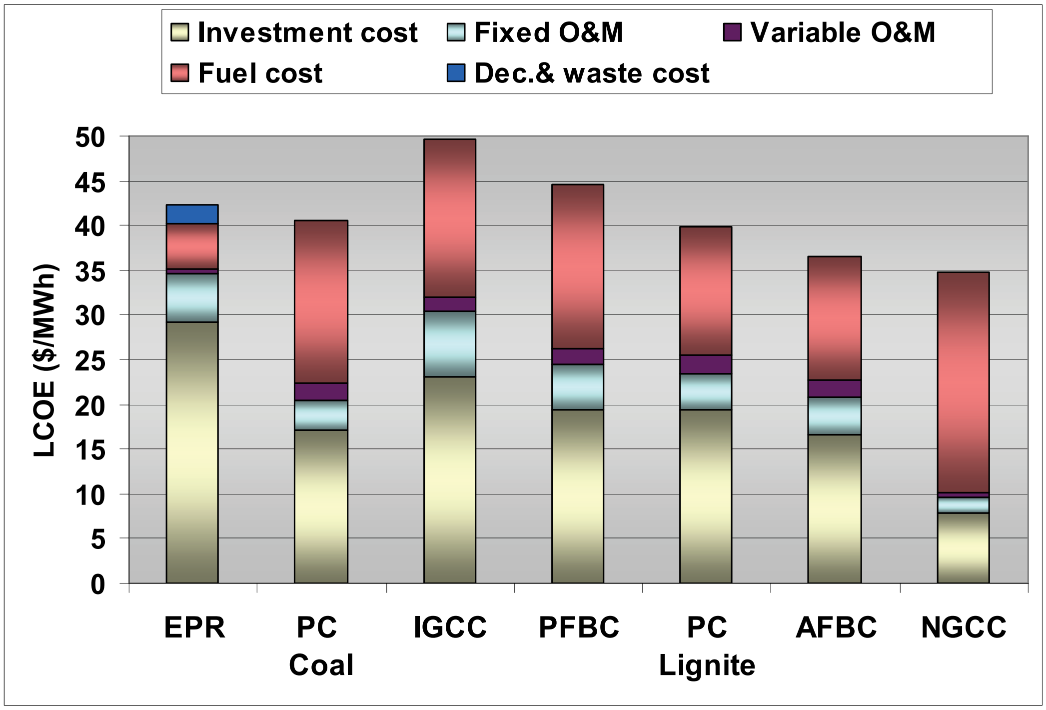

FIGURE 4.5 Pre-tax LCOE by Component for 2003 Fuel Prices and 10% Discount Rate (in U.S. Dollars)

4.3.2 LCOE Results, 2015 Fuel Prices, No Carbon Cost

The results obtained for the before-tax LCOE using the fuel price level in 2015 are presented in Table 4.3 and Figure 4.6. The main impact of fuel prices in 2015 is seen on the levelized cost of the NGCC candidate, which increases significantly due to the high escalation of natural gas prices. The LCOE results for nuclear and lignite-fired technologies remain the same since no real fuel price escalation is applied for these fuels.

TABLE 4.3 Pre-Tax LCOE for 2015 Fuel Prices (in U.S. Dollars)

Discount Rate (%)	EPR Nuclear (1500 MW)	PC Coal (400 MW)	IGCC Coal (300 MW)	PFBC Coal (150 MW)	PC Lignite (500 MW)	AFBC Lignite (150 MW)	NGCC Nat. Gas (300 MW)
5	29.74	31.4	37.89	34.41	31.49	29.32	37.21
8	37.04	35.69	43.65	39.28	36.34	33.48	39.04
10	42.29	38.77	47.8	42.78	39.82	36.48	40.08

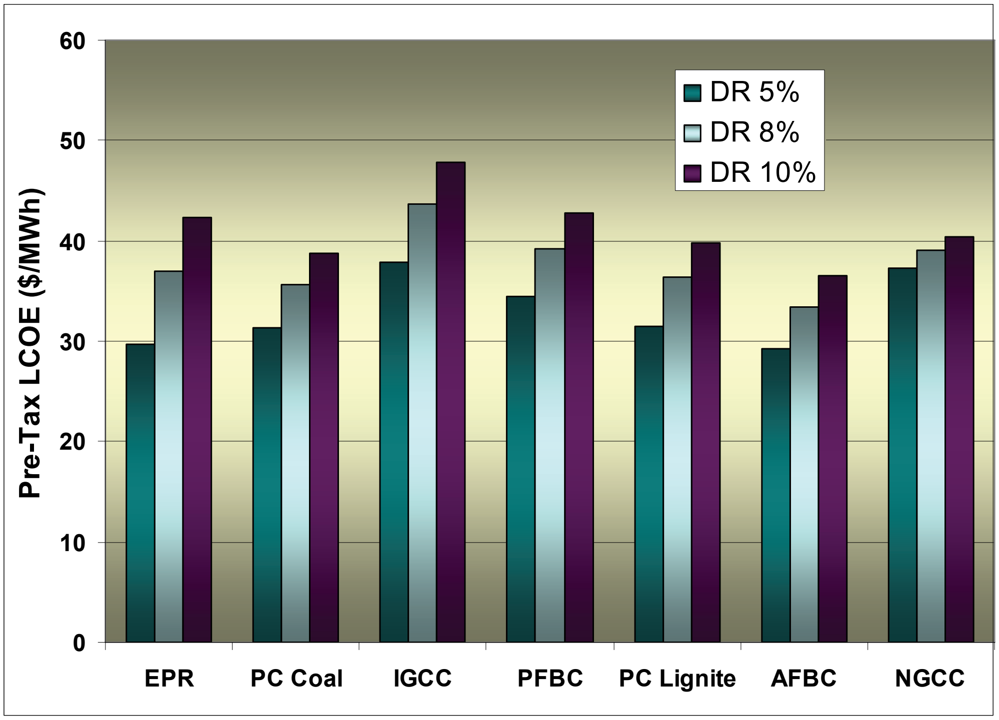

FIGURE 4.6 Pre-Tax LCOE for 2015 Fuel Prices (in U.S. Dollars)

As shown in Figure 4.6, the EPR nuclear candidate remains a competitive expansion option, especially when lower discount rates are used. For comparison, at a 5% discount rate, the LCOE of the EPR candidate is $29.74/MWh, while the LCOE of the NGCC amounts to $37.21/MWh. On the other hand, if a 10% discount rate is used for present value calculations, the LCOE of the EPR candidate is $42.29/MWh, while the LCOE of the NGCC is slightly lower at $40.08/MWh. The relative shares of different cost components in the total pre-tax LCOE of different candidate technologies for the level of fuel prices in 2015 is presented in Table 4.4 and illustrated in Figures 4.7 through 4.9. Again, the results are expressed in 2003 dollars and the calculations were performed using discount rates of 5%, 8%, and 10%.

TABLE 4.4 Breakdown of Pre-tax LCOE by Component for 2015 Fuel Prices (in U.S. Dollars)

LCOE ($/MWh)	EPR Nuclear 1500 MW	PC Coal 400 MW	IGCC Coal 300 MW	PFBC Coal 150 MW	PC Lignite 500 MW	AFBC Lignite 150 MW	NGCC Nat. Gas 300 MW
Discount Rate 5%							
Investment cost	16.63	9.77	13.13	11.09	11.03	9.48	4.50
Fixed O&M	5.49	3.35	7.41	4.94	4.08	4.08	1.69
Variable O&M	0.49	1.82	1.62	1.92	2.00	2.00	0.50
Fuel cost	5.13	16.47	15.73	16.47	14.38	13.76	30.00
Dec.& waste cost	2.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	29.74	31.40	37.89	34.41	31.49	29.32	37.21
Discount Rate 8%							
Investment cost	23.94	14.06	18.89	15.95	15.88	13.65	6.47
Fixed O&M	5.49	3.35	7.41	4.94	4.08	4.08	1.69
Variable O&M	0.49	1.82	1.62	1.92	2.00	2.00	0.50
Fuel cost	5.13	16.47	15.73	16.47	14.38	13.76	30.00
Dec.& waste cost	2.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	37.04	35.69	43.65	39.28	36.34	33.48	39.04
Discount Rate 10%							
Investment cost	29.19	17.14	23.03	19.45	19.36	16.64	7.89
Fixed O&M	5.49	3.35	7.41	4.94	4.08	4.08	1.69
Variable O&M	0.49	1.82	1.62	1.92	2.00	2.00	0.50
Fuel cost	5.13	16.47	15.73	16.47	14.38	13.76	30.00
Dec.& waste cost	2.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	42.29	38.77	47.80	42.78	39.82	36.48	40.08

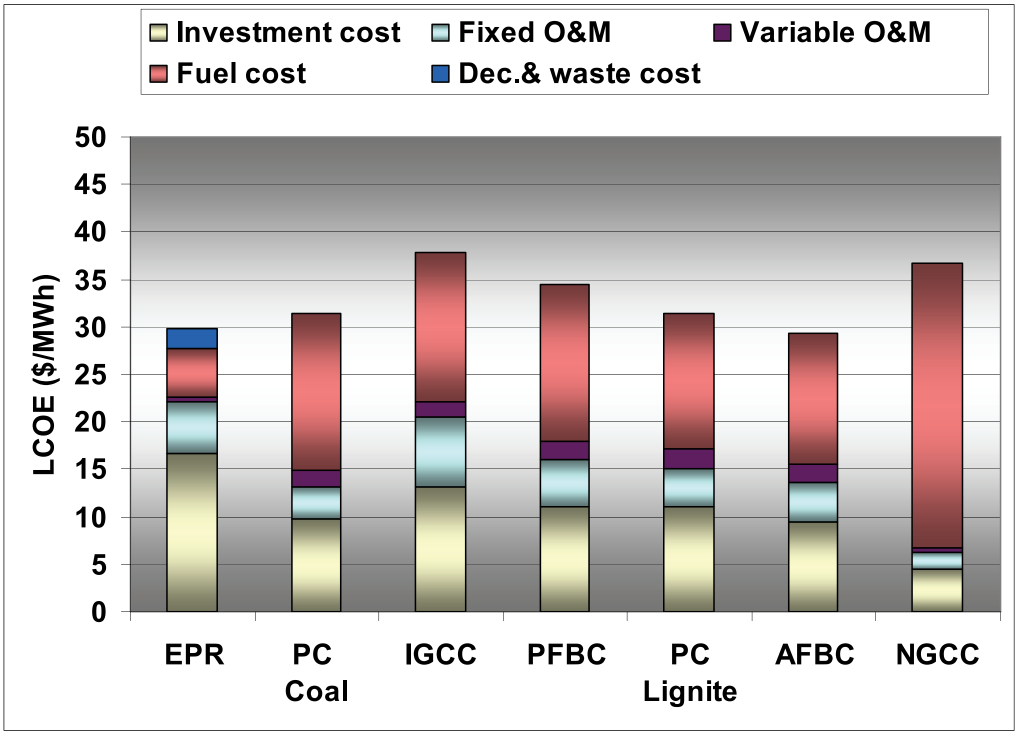

FIGURE 4.7 Pre-tax LCOE by Component for 2015 Fuel Prices and 5% Discount Rate (in U.S. Dollars)

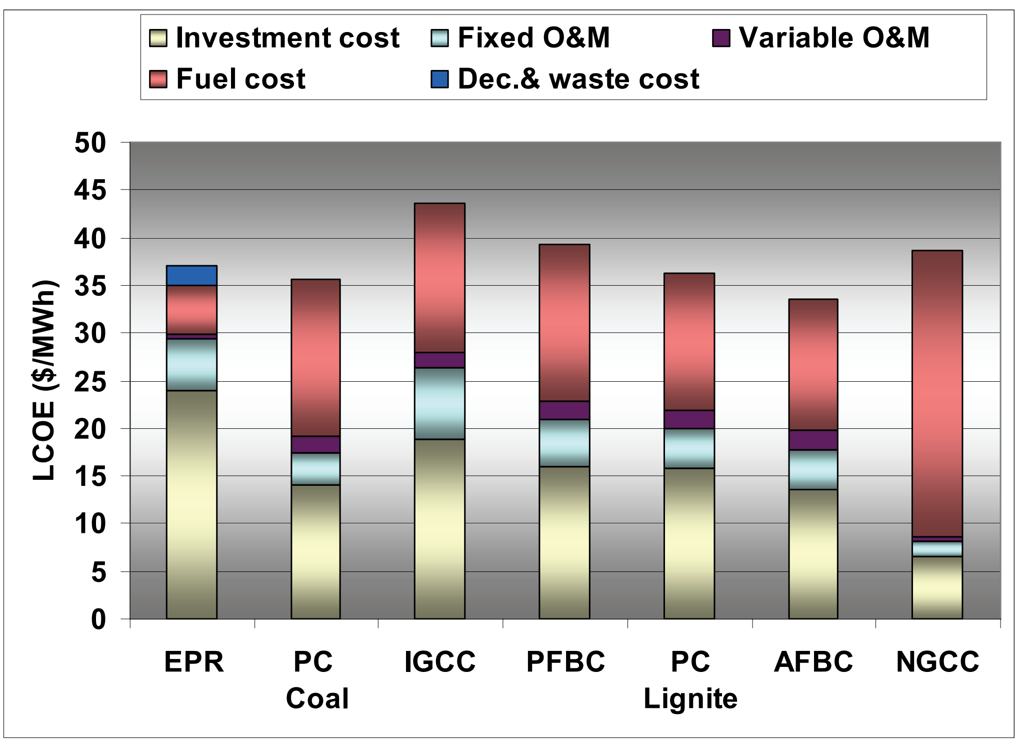

FIGURE 4.8 Pre-tax LCOE by Component for 2015 Fuel Prices and 8% Discount Rate (in U.S. Dollars)

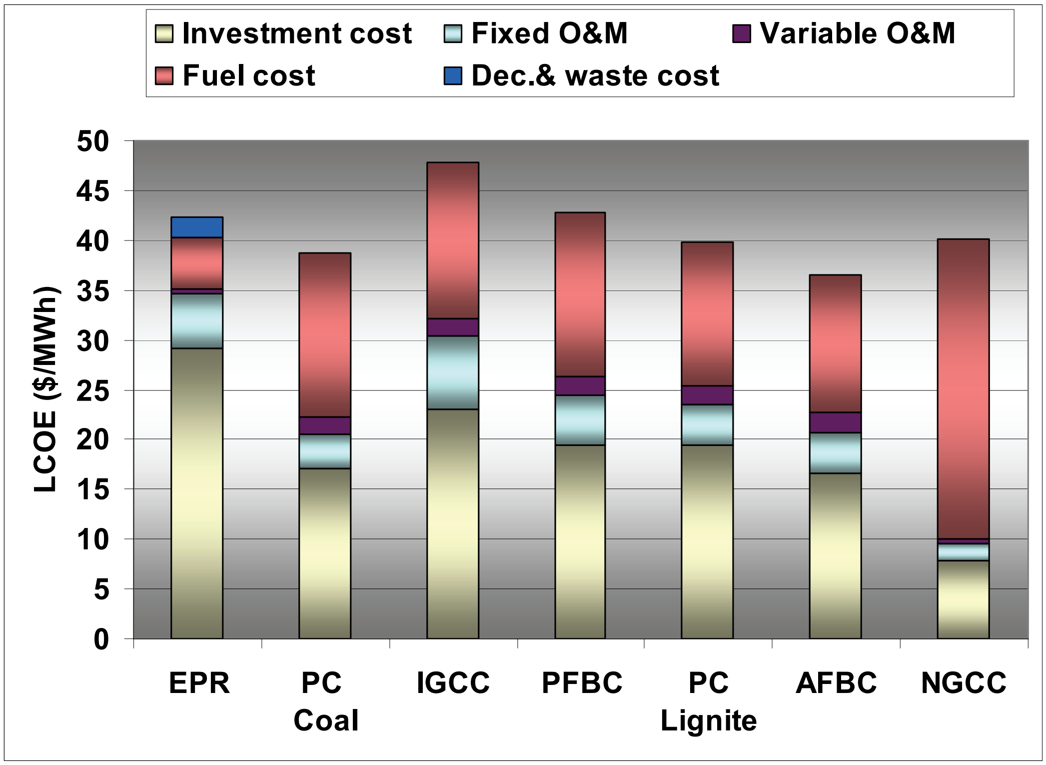

FIGURE 4.9 Pre-tax LCOE by Component for 2015 Fuel Prices and 10% Discount Rate (in U.S. Dollars)

4.3.3 LCOE Results, 2015 Fuel Costs, Carbon Costs ($10–15/ton)

The pre-tax LCOE analysis was also performed, taking into account the CO_2 emission allowance costs. The analysis was carried out for fuel prices in 2015 and CO_2 costs of $10 and $15 USD per ton. If the CO_2 emission costs are taken into account, the nuclear technology becomes very competitive for all three discount rates used (5%, 8%, and 10%). Even with a relatively low value of CO_2 emission cost of $10/ton, the nuclear candidate is clearly the lowest cost option. Figures 4.10 and 4.11 illustrate the results of this analysis.

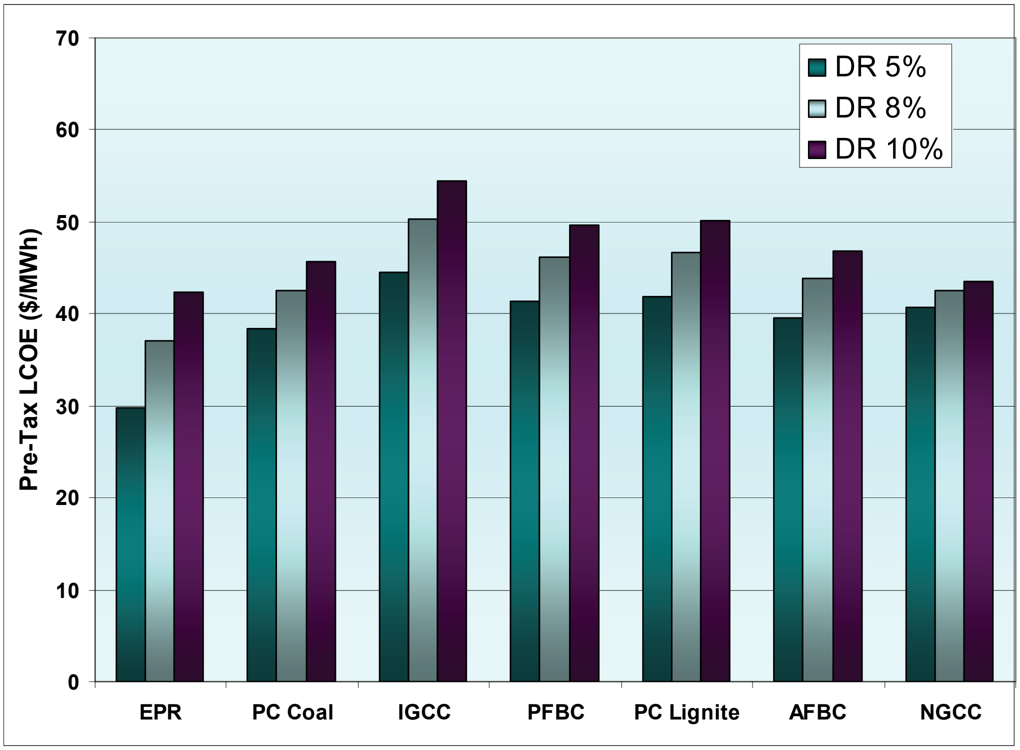

FIGURE 4.10 Pre-Tax LCOE for 2015 Fuel Prices and CO_2 Cost of $10/ton (in U.S. Dollars)

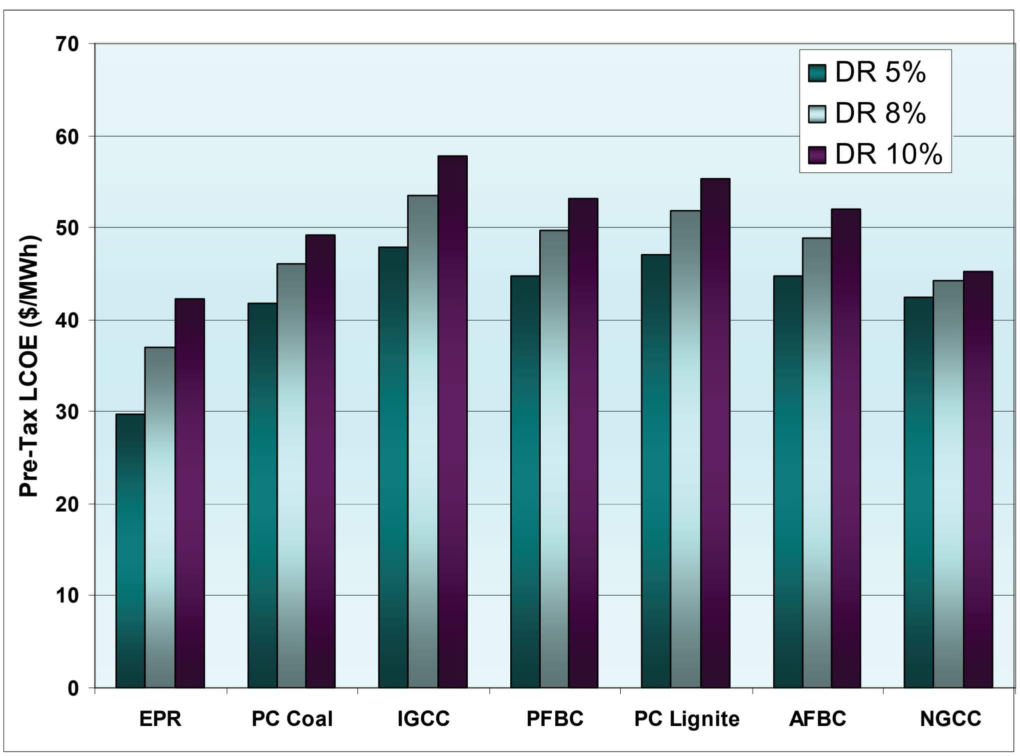

FIGURE 4.11 Pre-Tax LCOE for 2015 Fuel Prices and CO_2 Cost of $15/ton (in U.S. Dollars)

APPENDIX 5
METHODOLOGY, ASSUMPTIONS, AND RESULTS OF THE WASP ANALYSIS

5.1 METHODOLOGY

The Wien Automatic System Planning Package (WASP) is an optimization model for examining medium- to long-term development options for electrical generating systems. The goal of electric power systems expansion planning is to determine the optimal pattern of system expansion to meet the electricity requirements over a given period. WASP helps to find the economically optimum expansion plan for a power generating system for up to 30 years, within constraints specified by the user. The optimum is evaluated in terms of the minimum present worth of total system costs. WASP uses probabilistic estimation of production costs, amount of energy-not-served (ENS), and reliability, together with a dynamic programming method of optimization for comparing the costs of alternative system expansion policies. Each possible sequence of power units added to the system (expansion plan or expansion policy) that meets the specified constraints is evaluated by a cost function (the objective function) comprising (1) capital investment costs, (2) salvage value of investment costs, (3) fuel costs, (4) fuel inventory costs, (5) nonfuel operation and maintenance costs, and (6) cost of expected amount of energy-not-served. WASP comprises the following eight modules. A simplified flow chart of the WASP model is shown in Figure 5.1.

(Module 1) **LOADSY** (Load System Description): Processes information describing the peak loads and load duration curves for up to 30 years. The objective of LOADSY is to prepare all the demand information needed by subsequent modules.

(Module 2) **FIXSYS** (Fixed System Description): Processes information describing the existing generating system. This includes performance and cost characteristics of all generating units in the system at the start of the study period and a list of retirements and "fixed" additions to the system. Fixed additions are power plants already committed and not subject to change.

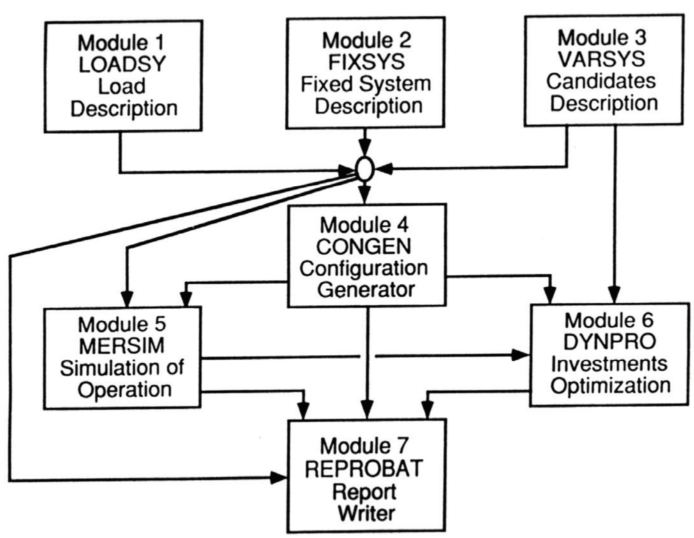

FIGURE 5.1 Simplified Flow Chart for the WASP Model

(Module 3) **VARSYS** (Variable System Description): Processes information describing the various generating units to be considered as candidates for expanding the generating system.

(Module 4) **CONGEN** (Configuration Generator): Calculates all possible year-to-year combinations of expansion candidate additions that satisfy certain input constraints and that, in combination with the existing system, can adequately meet the projected electricity demand.

(Module 5) **MERSIM** (Merge and Simulate): Considers all configurations put forward by CONGEN and uses probabilistic simulation of system operation to calculate the associated production costs, ENS, and system reliability for each configuration. The module also calculates plant loading orders, if desired, and makes use of all previously simulated configurations.

(Module 6) **DYNPRO** (Dynamic Programming Optimization): Determines the optimum expansion plan as based on previously derived operating costs along with input information on capital cost, ENS cost, and economic parameters and reliability criteria.

(Module 7) **REMERSIM** (Re-MERSIM): Simulates the configurations contained in the optimized solution. By providing a detailed output of the simulation, REMERSIM allows the user to analyze particular components of the production-cost calculation, such as unit-by-unit capacity factors for each season and hydroelectric condition.

(Module 8) **REPROBAT** (Report Writer of WASP in a Batched Environment): Writes a report summarizing the total or partial results for the optimum or near-optimum power system expansion plan and fixed expansion schedules.

5.2 ASSUMPTIONS FOR THE WASP MODEL

5.2.1 Base Case

The analysis used EMA official projections of electricity consumption and load forecasts. The growth in load is driven by assumptions regarding macroeconomic drivers. The load and capacity forecasts are presented in Figures 5.2 and 5.3. The WASP system and technology parameters are presented in Tables 5.1 and 5.2. The discount rate of 7% was chosen for the WASP analysis as it is close to the rate used by the EBRD (7.4% as of the end of 2006). A $10/ton carbon cost was chosen. This is a conservative assumption, below the current price of CO_2 allowances in the EU trading system.

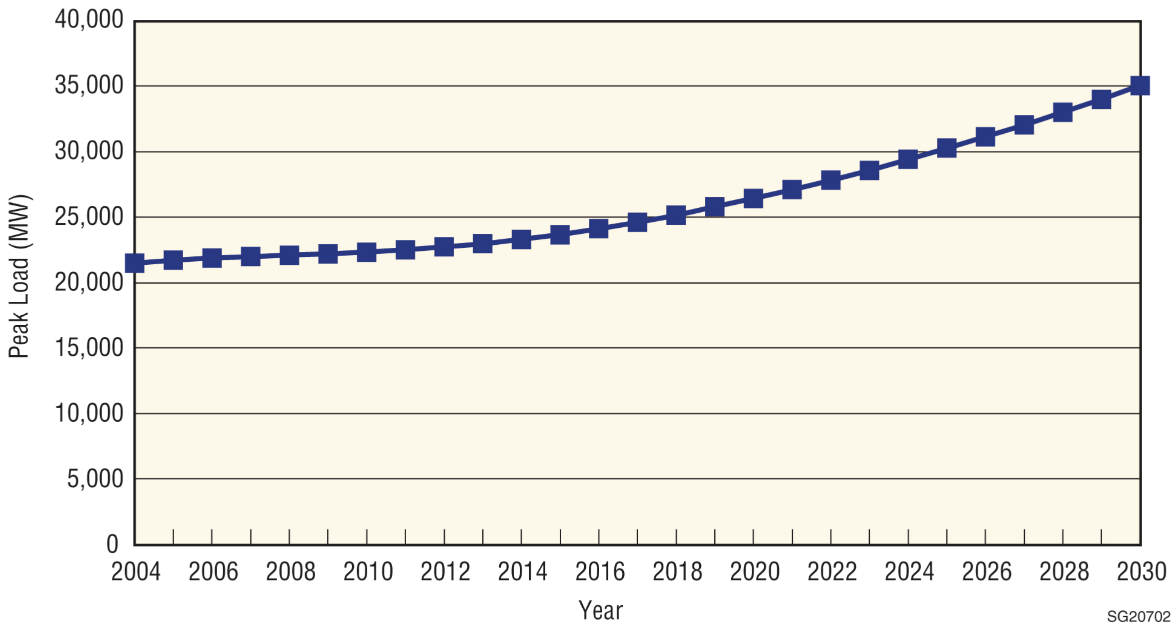

FIGURE 5.2 Load Forecast

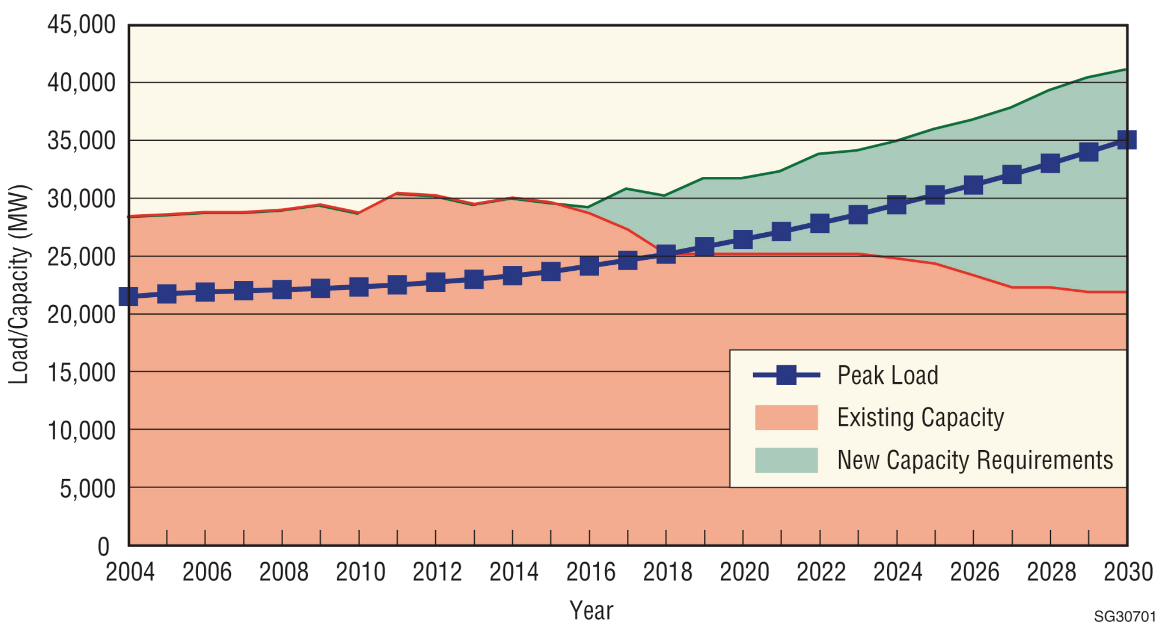

FIGURE 5.3 Load and Capacity Balance

TABLE 5.1 WASP System Parameters

Parameter	Value	Comment
Study period	2004–2033	Scope of the current study.
Planning period	2006–2030	Investment period for the study.
Number of periods in each year	12	12 monthly periods to capture seasonality of demand.
Number of hydrological conditions	1	Hydro power plays a minimal role in Poland.
Load forecast	Long-term demand forecast (up to 2025) developed by the Gdansk Institute for Market Economics	This is the latest load forecast that was also used by the Electricity Market Agency (EMA, 2006[5]).
Reserve margin range	10%–30%	The model will build capacity such that the resulting reserve margin stays in the specified range. Reserve margins for a thermal-dominated system are typically around 18-20%. We chose 10–30% to be conservative.
Unit dispatch	Economic loading order	Production cost-based loading order, typically used in determining the priority of dispatching power to meet demand on the grid.
Spinning reserve requirement	Largest unit size	Provides enough spinning reserve to cover the forced outage of the largest unit in operation. This is a typical requirement in many power systems.
Present value date	January 1, 2004	All costs are expressed in U.S. dollars (constant prices as of January 1, 2004).
Discount rate for cost discounting	7.0%[6]	This is the discount rate currently in use by EBRD for Poland (one of the EU countries it provides financing) — this rate assumes some governmental guarantees as a backstop to EBRD financing.
Salvage value of capital investments	Sinking fund depreciation method	This is the recommended depreciation method of the WASP methodology experts. According to generally accepted accounting principles, a straight-line method may be more conservative; however, based on previous studies, this depreciation method is taken as the more standardized approach.
CO_2 allowance costs	\$10 per ton of CO_2	A conservative assumption that is also used by the EMA study (2006).
Energy-not-served cost	0.5 \$/kWh	Typical value for a country like Poland. Also, this value was used by the EMA study.

5 J. Marecki and M. Duda (EMA), "Why There is a Necessity to Build Nuclear Power Plants in Poland," NPPP 2006, International Conference, Nuclear Power Plants for Poland, Warszawa 2006.

6 A sensitivity analysis will be performed with a higher discount rate of 12%.

TABLE 5.2 WASP Technology Parameters (All Costs are in 2004 U.S. Dollars)

	Nuclear	Lignite		Coal			Natural gas
Candidate Technology	**EPR**	**PC**	**AFBC**	**PC**	**IGCC**	**PFBC**	**NGCC**
Net generating capacity (MW)	1,500[7]	500	150	400	300	150	300
Overnight construction cost ($/kW)	1,895	1,280	1,100	1,160	1,450	1,240	590
Construction period (years)	7	4	4	4	4	4	2
Fixed O&M costs ($/kW-yr)	42.29	30.	30.	25.2	51.96	35.04	13.44
Variable O&M costs ($/MWh)	0.49	2.0	2.0	1.82	1.62	1.92	0.5
Unit net efficiency (%)	37.0	41.5	41.7	43.0	45.0	43.0	58.0
Fuel cost ($/GJ)	0.53	1.66	1.59	2.19	2.19	2.19	3.98
Equivalent forced outage rate (%)	4	3	10	9	5	5	4
Maintenance time (days/year)	30	40	42	42	42	42	20
Economic plant life (years)	40	40	40	40	40	40	30

Data for the technology candidates were obtained from NEA/IEA.[8] The construction period for the EPR has been extended from five to seven years to account for the application in Poland. The breakdown of the total O&M costs into fixed and variable components was performed using the EPRI approach utilizing the expected capacity factor of the unit. The data for the candidate technologies were further refined in the EMA study (EMA, 2006) to adjust for the conditions in Poland.

Fuel prices were projected over the study period according to the World Energy Outlook 2005 forecast (Table 5.3). The OECD steam coal import price was used to project future prices of coal, while the European import price was used for the projection of natural gas prices. No real price escalation was used for the prices of nuclear fuel and lignite.

[7] Sensitivity analysis was performed using a smaller unit size.

[8] OECD report "Projected Costs of Generating Electricity — 2005 Update," published by the IEA. Available at http://www.iea.org/Textbase/publications/free_new_Desc.asp?PUBS_ID=1472.

TABLE 5.3 Fuel Prices

Type of Import	2004	2010	2020	2030
European imports of natural gas ($/MMBtu)[9]	4.20	5.00	5.20	5.60
OECD steam coal imports ($/ton)	55	49	50	51

5.2.2 Smaller Unit Case

A sensitivity study was performed to determine if a smaller size of a nuclear candidate would be more favorable for the future system expansion. For this sensitivity study, the size of the EPR nuclear candidate was reduced from 1,500 MW to 1,000 MW. All other parameters are the same as in the Base Case.

5.2.3 High Discount Rate Case

Except for the change in discount rate to 12 percent, all other parameters remain the same as in the Base Case.

5.2.4 Zero Carbon Cost Case

Except for removing the carbon costs, all other parameters remain the same as in the Base Case.

5.3 RESULTS OF THE WASP ANALYSIS

The study team analyzed the expansion candidates during the period 2016–2030 for all four WASP cases. This analysis provided data on the following:

- Annual Capacity Expenses,
- Cumulative Capacity Expansions,
- Aggregate Installed Capacity, and
- Operating and Investment Costs.

[9] The study team used the 2005 World Energy Outlook to determine the projected price of natural gas; it is expected to rise to $5.20–5.60 per million British Thermal Units (MMBtu) in the 2020–2030 time frame (or about 25% above the current prices); if geopolitical tensions rise between Russia and its Central and Eastern European customers, natural gas prices could rise more significantly, such prices for natural gas would make NGCCs economically uncompetitive.

5.3.1 Results of the Base Case

The study team found that two new nuclear energy units for a total of 3,000 MWe will be introduced in 2017 with cumulative nuclear capacity additions of 13,500 MWe by 2030 (see Figures 5.4 through 5.6). The operating and investment cash flow to support all capacity additions are shown in Figure 5.7. The peak years in cash flow occur when new nuclear additions are required (2015–2025); the annual cash flows reach as high as $7.3 billion USD in the 2015 time frame.

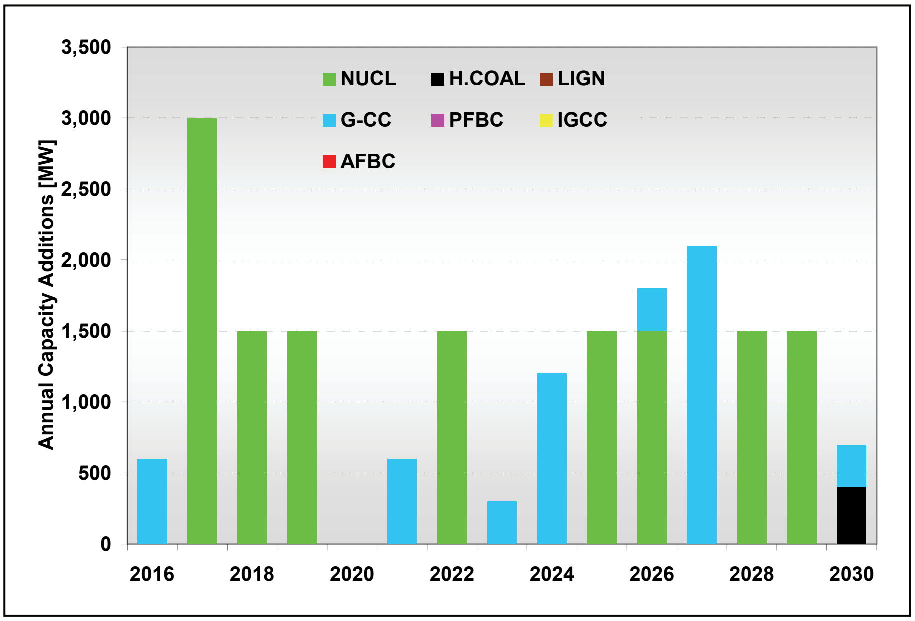

FIGURE 5.4 Base Case, Annual Capacity Additions (2016–2030)

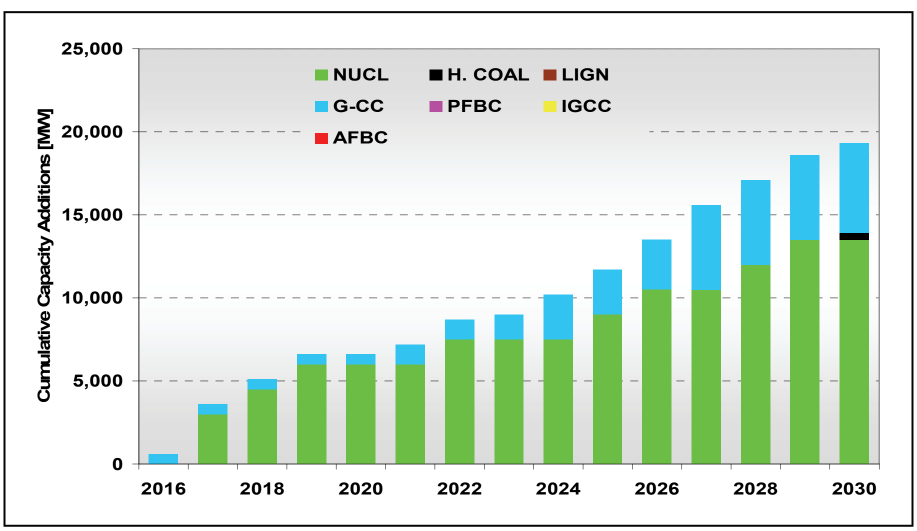

FIGURE 5.5 Base Case, Cumulative Capacity Additions (2016–2030)

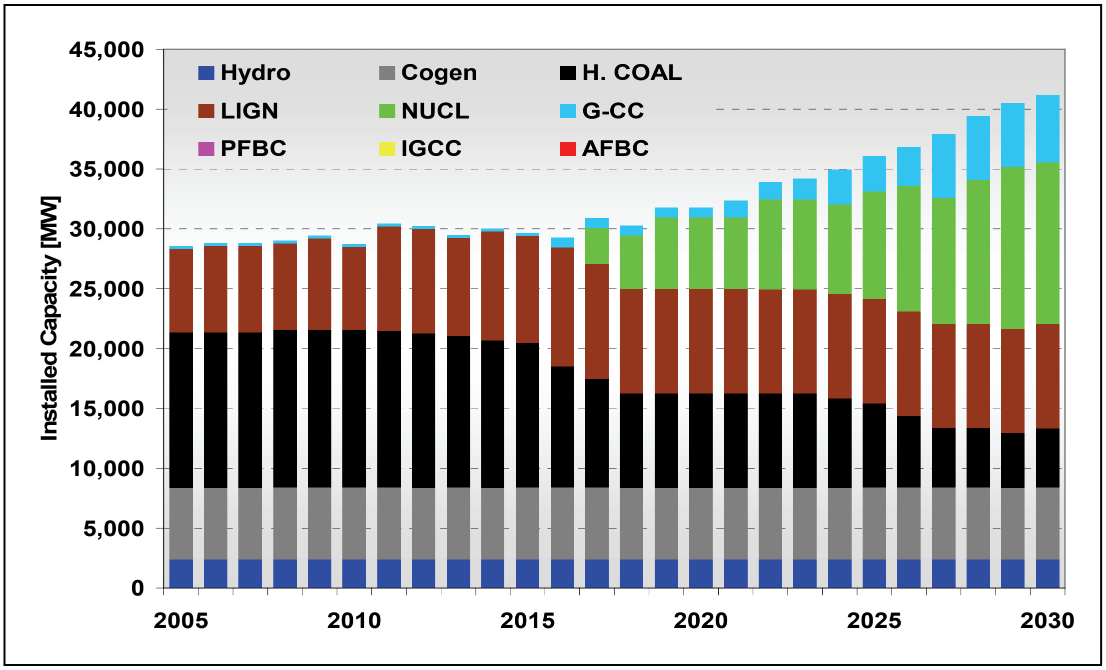

FIGURE 5.6 Base Case, Aggregate Installed Capacity (2005–2030)

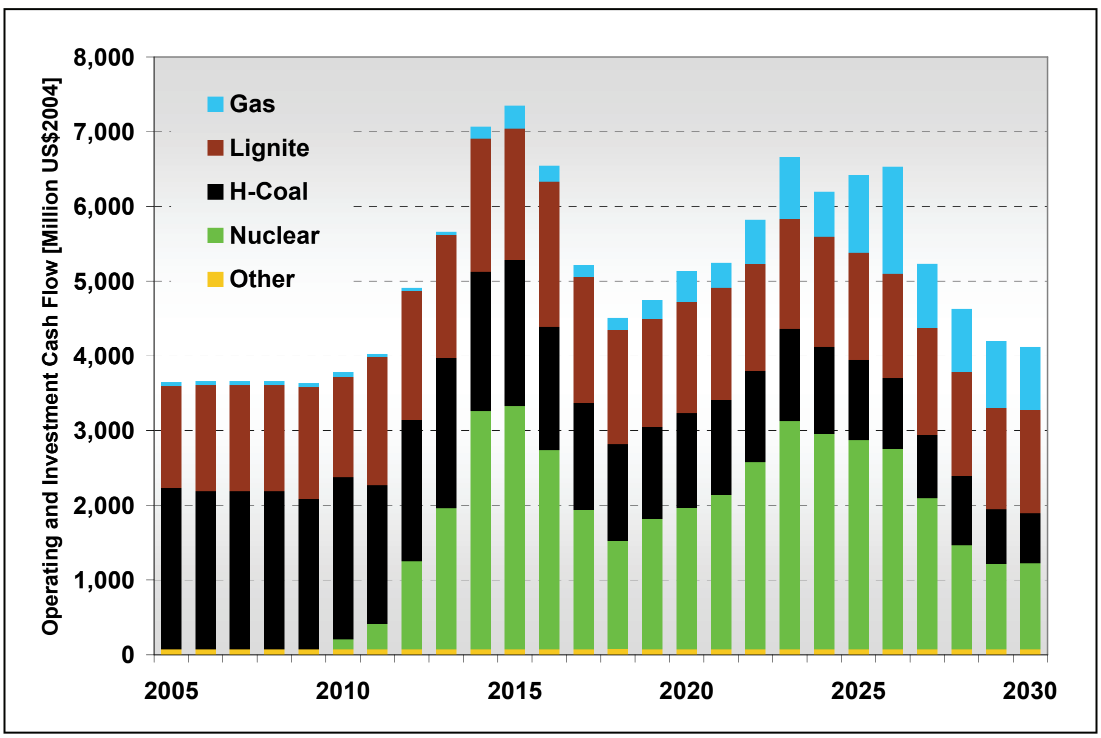

FIGURE 5.7 Base Case, Operating and Investment Costs (2005-2030) [Million $ USD 2004]

5.3.2 Results of 1000 MWe Case

The study team found that a smaller-sized nuclear reactor (i.e., the 1000 MWe alternative case) has a slightly higher overnight cost than the EPR, but the savings in dispatching smaller units of base load power in the Polish grid more than counterbalance any overnight cost increases. The study team judged that significantly smaller reactors (for example, 100–500 MWe) would not be economically competitive because the significantly higher overnight costs for those smaller reactors would dominate the WASP calculation. In addition, the study team found that one new nuclear unit would be introduced in 2016, with cumulative nuclear capacity additions of about 17,000 MWe by 2030 (see Figures 5.8 through 5.10). The operating and investment cash flow to support all capacity additions are shown in Figure 5.11. The peak years in cash flow occur when new nuclear additions are required (2015–2025); the annual cash flows reach as high as $7.6 billion in the 2015 time frame.

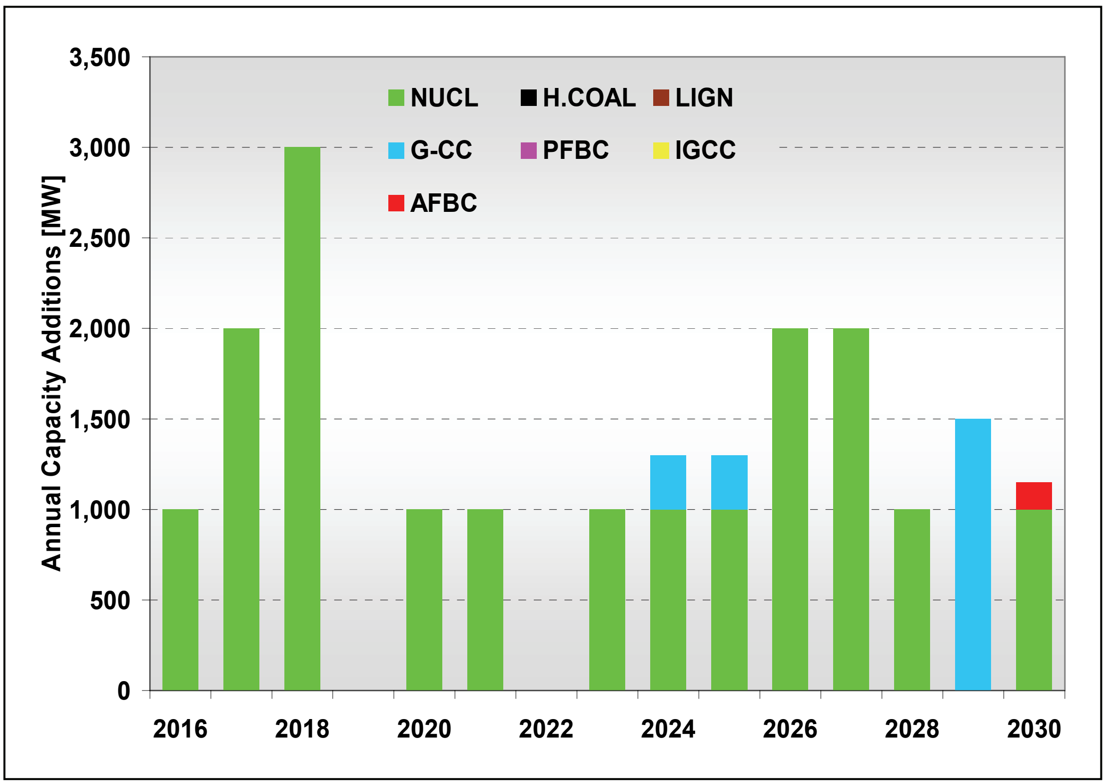

FIGURE 5.8 Smaller Reactor Case, Annual Capacity Additions (2016-2030)

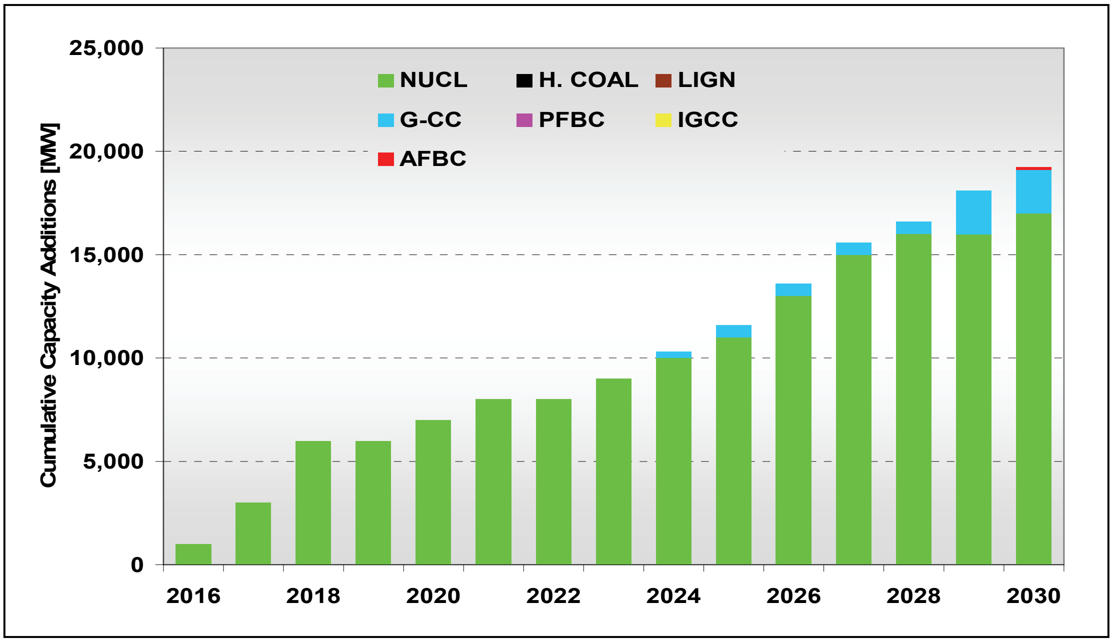

FIGURE 5.9 Smaller Reactor Case, Cumulative Capacity Additions (2016–2030)

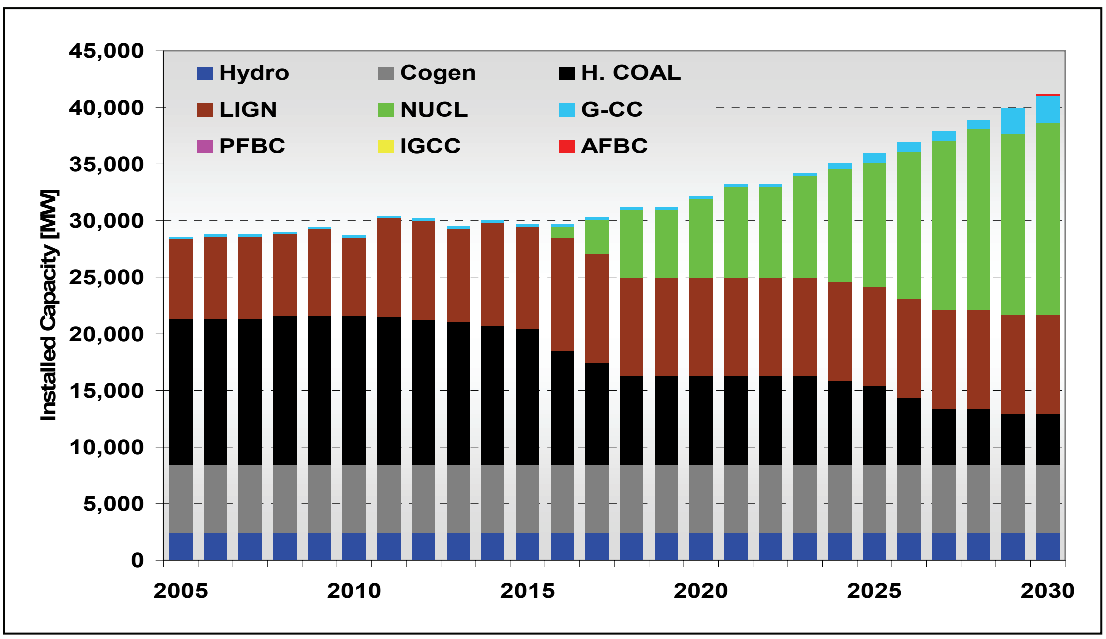

FIGURE 5.10 Smaller Reactor Case, Aggregate Installed Capacity (2005–2030)

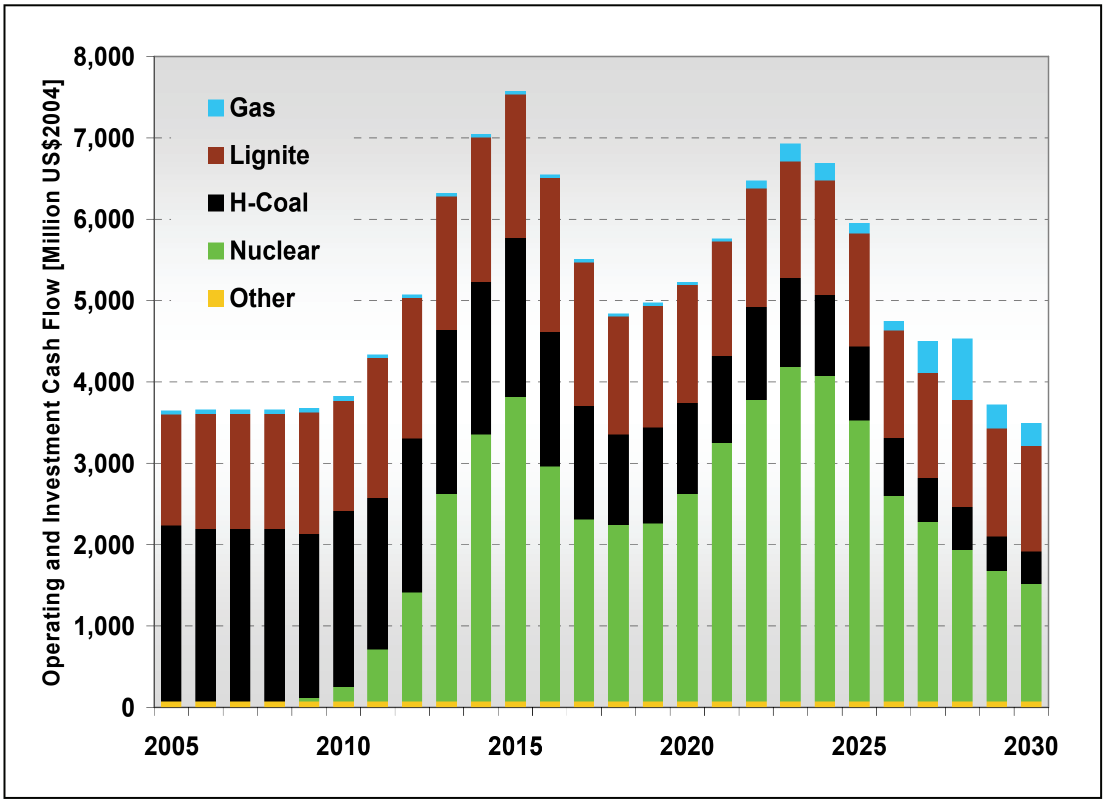

FIGURE 5.11 Smaller Reactor Case, Operating and Investment Costs (2005–2030) [Million $ USD 2004]

5.3.3 Results of the High Discount Rate Case

The study team found that natural gas combined-cycle plants are the most economical in a high-discount-rate environment. It found that one new nuclear unit would be introduced very late in the expansion cycle (around 2026) and not expand further (see Figures 5.12 through 5.14). The operating and investment cash flow to support all capacity additions are shown in Figure 5.15. The peak years in cash flow occur when a large number of new gas-fired units are required (2022–2030); the annual cash flows reach as high as $7.1 billion in the 2023 time frame.

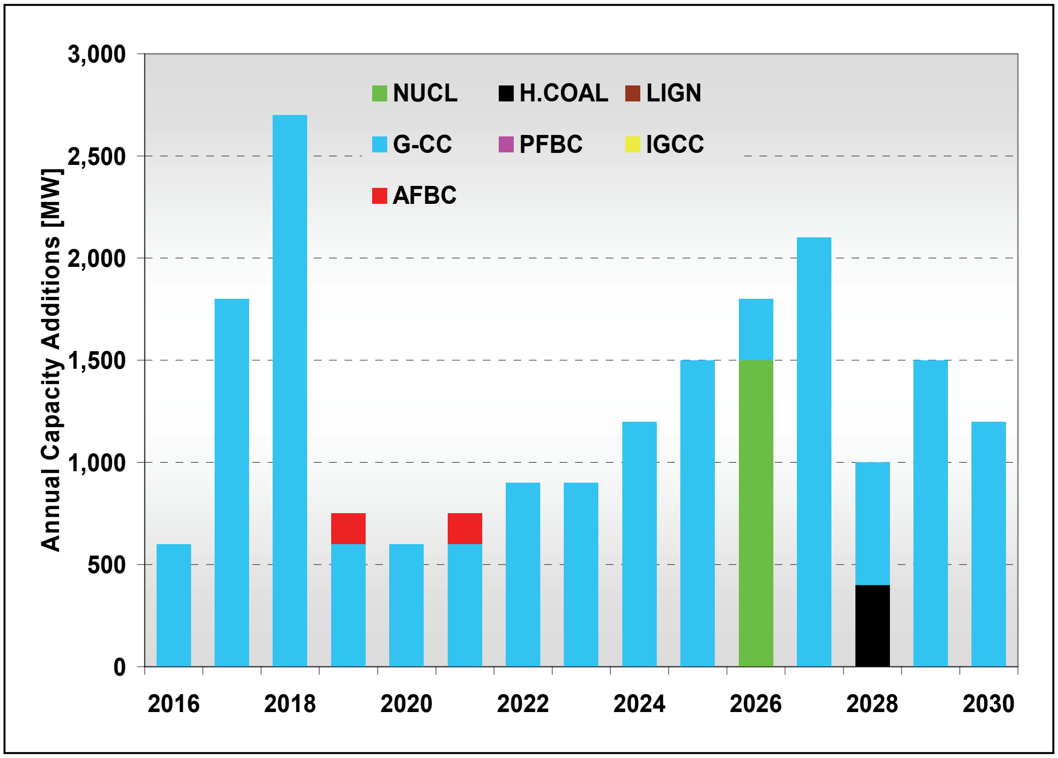

FIGURE 5.12 High Discount Rate Case, Annual Capacity Additions (2016–2030)

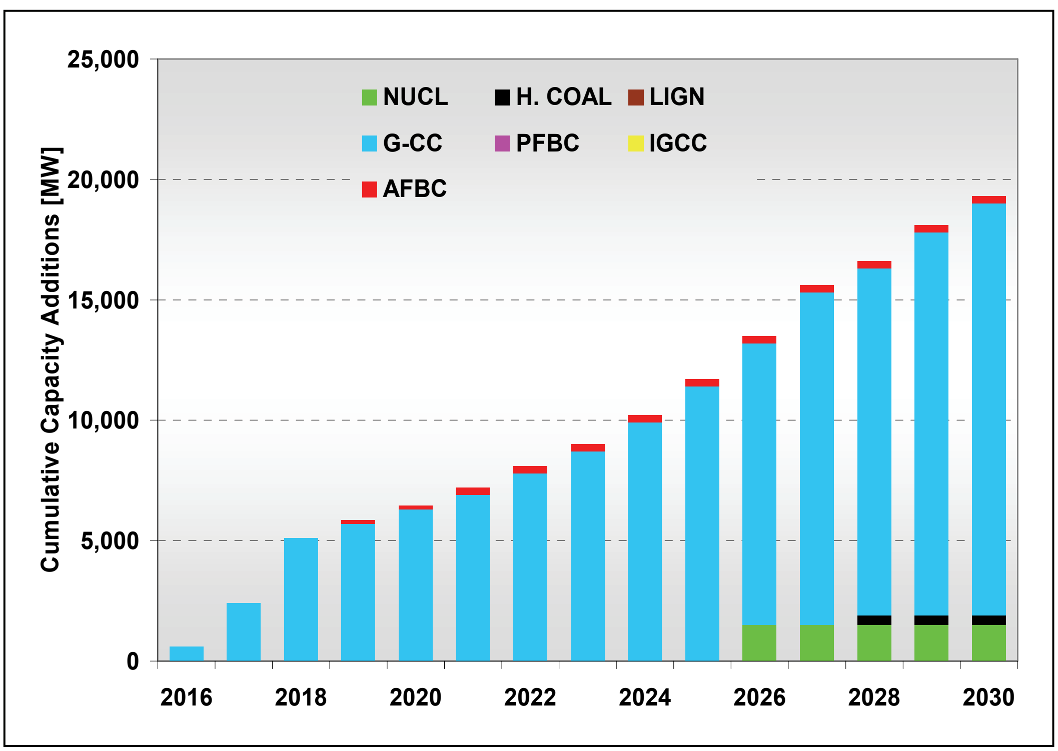

FIGURE 5.13 High Discount Rate Case, Cumulative Capacity Additions (2016–2030)

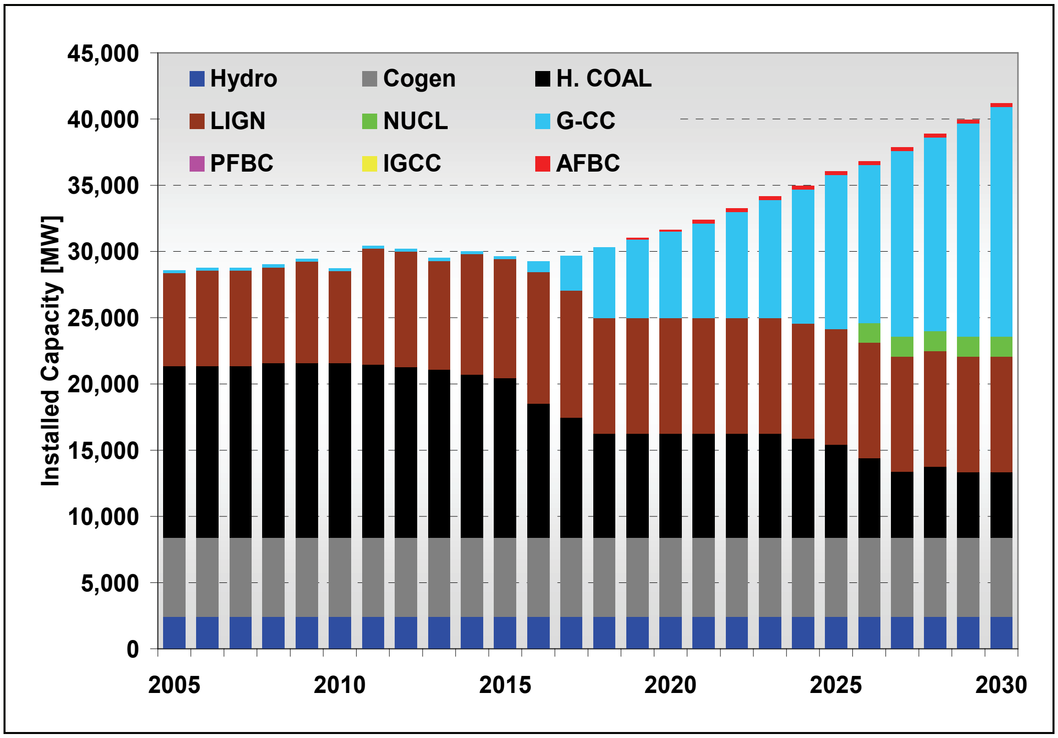

FIGURE 5.14 High Discount Rate Case, Aggregate Installed Capacity (2005–2030)

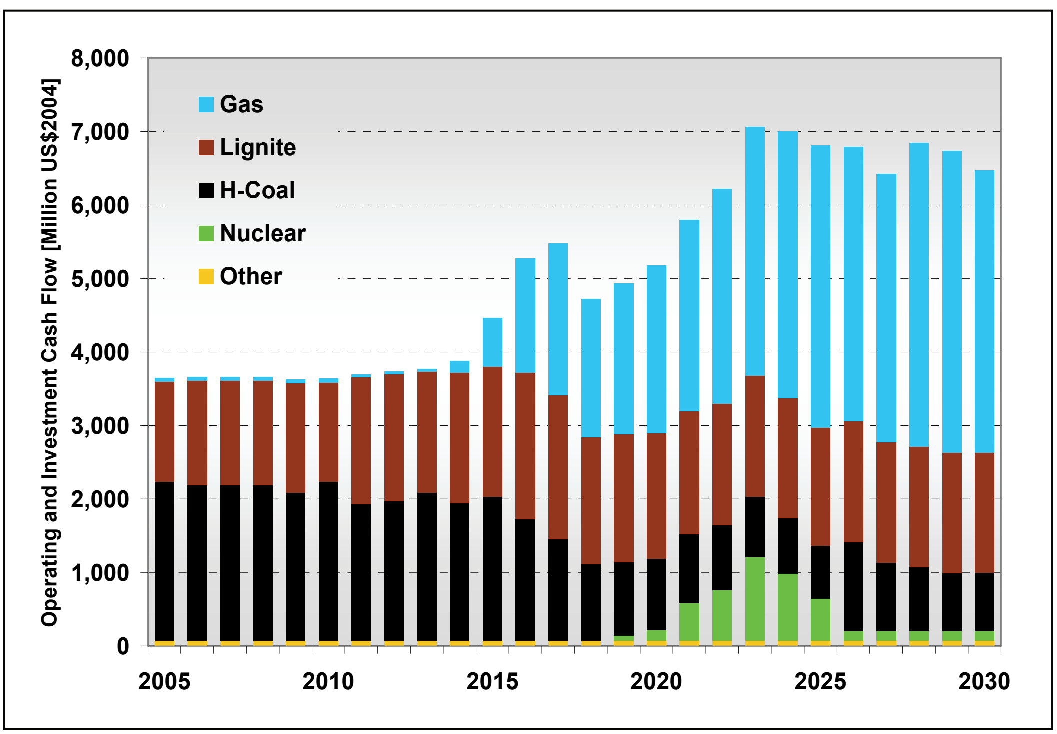

FIGURE 5.15 High Discount Rate Case, Operating and Investment Costs (2005–2030) [Million $ USD 2004]

5.3.4 Results of the Zero Carbon Cost Case

The study team found that efficient coal-fired plants (AFBCs) are the most economical in a zero-carbon-cost environment. It found that no new nuclear units would be introduced throughout the expansion cycle (see Figures 5.16 through 5.18). The operating and investment cash flow to support all capacity additions are shown in Figure 5.19. The peak years in cash flow occur when a large number of new coal-fired units are required (2020–2030); the annual cash flows reach as high as $5.5 billion in the 2023 time frame. This represents an annual savings of about $2 billion in the peak years compared to the other cases. Therefore, the net cost of imposing a $10/ton carbon cost is significant.

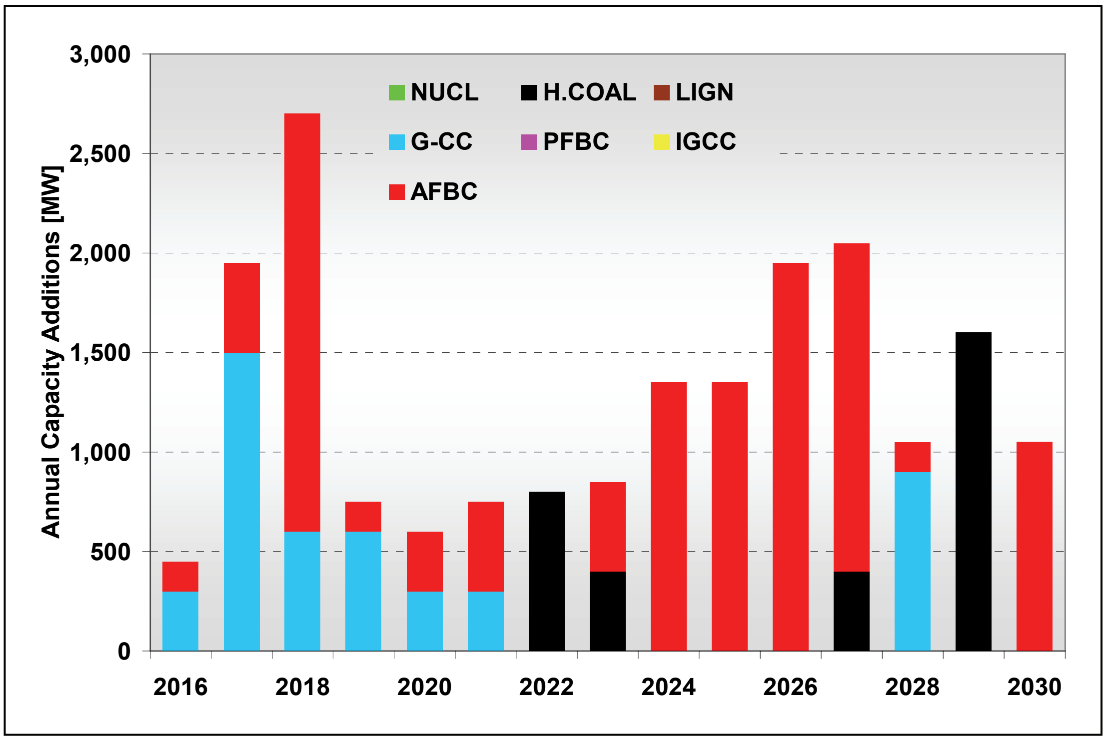

FIGURE 5.16 Zero Carbon Cost Case, Annual Capacity Additions (2016–2030)

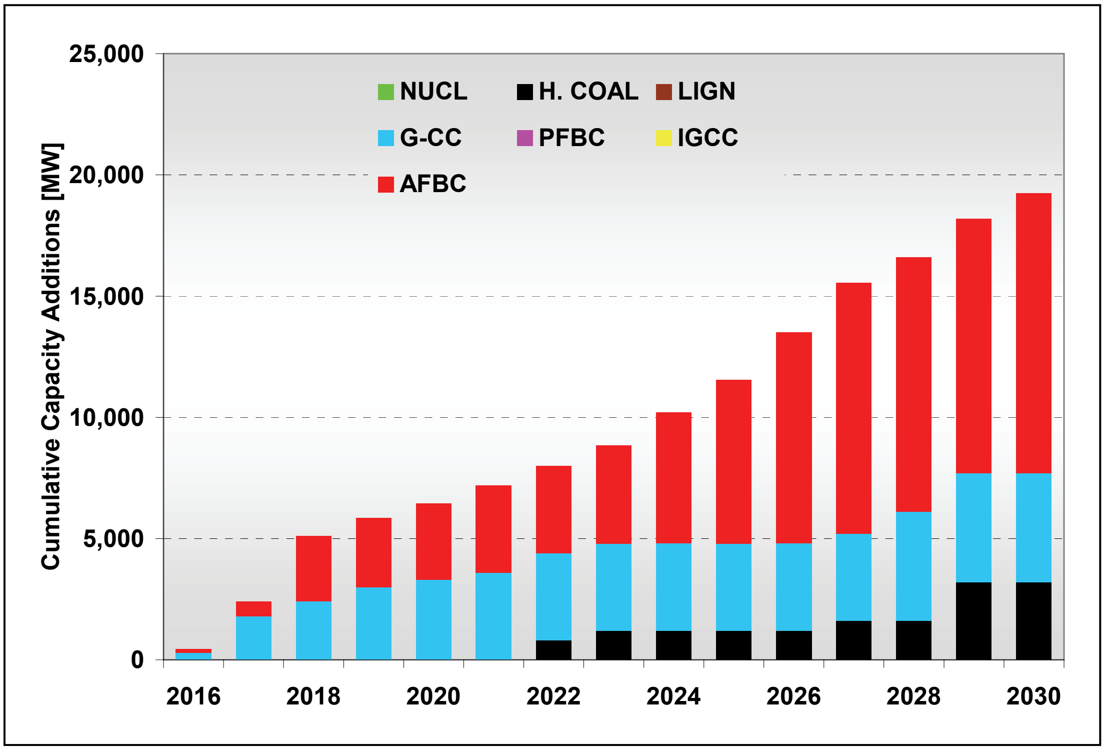

FIGURE 5.17 Zero Carbon Cost Case, Cumulative Capacity Additions (2016–2030)

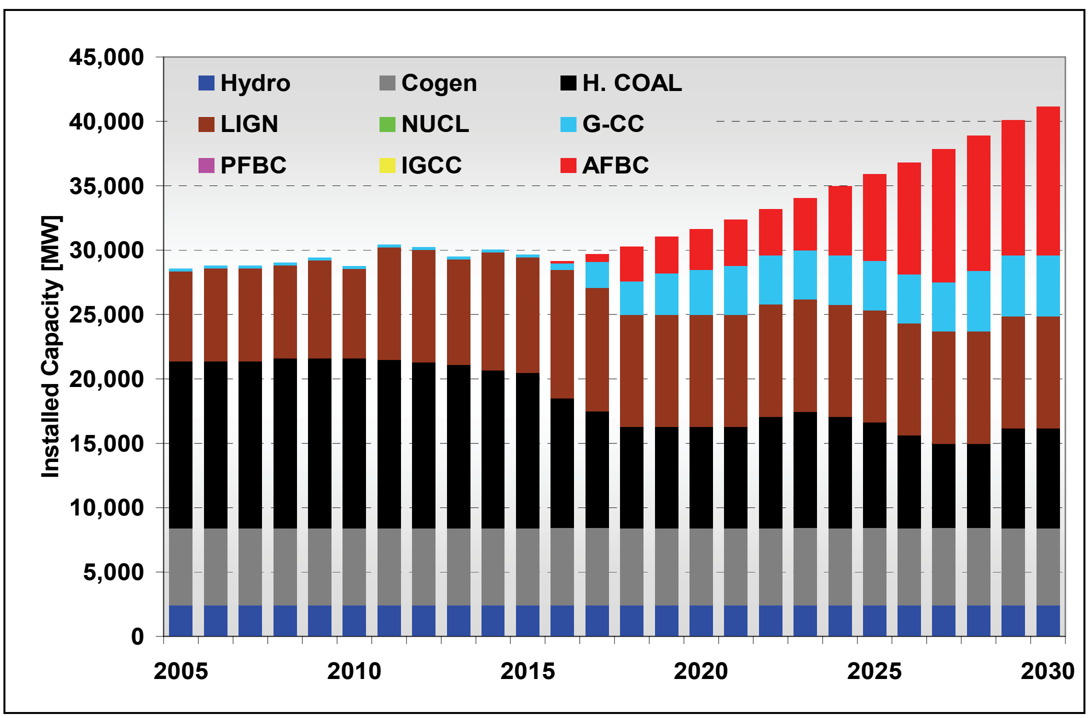

FIGURE 5.18 Zero Carbon Cost Case, Aggregate Installed Capacity (2005–2030)

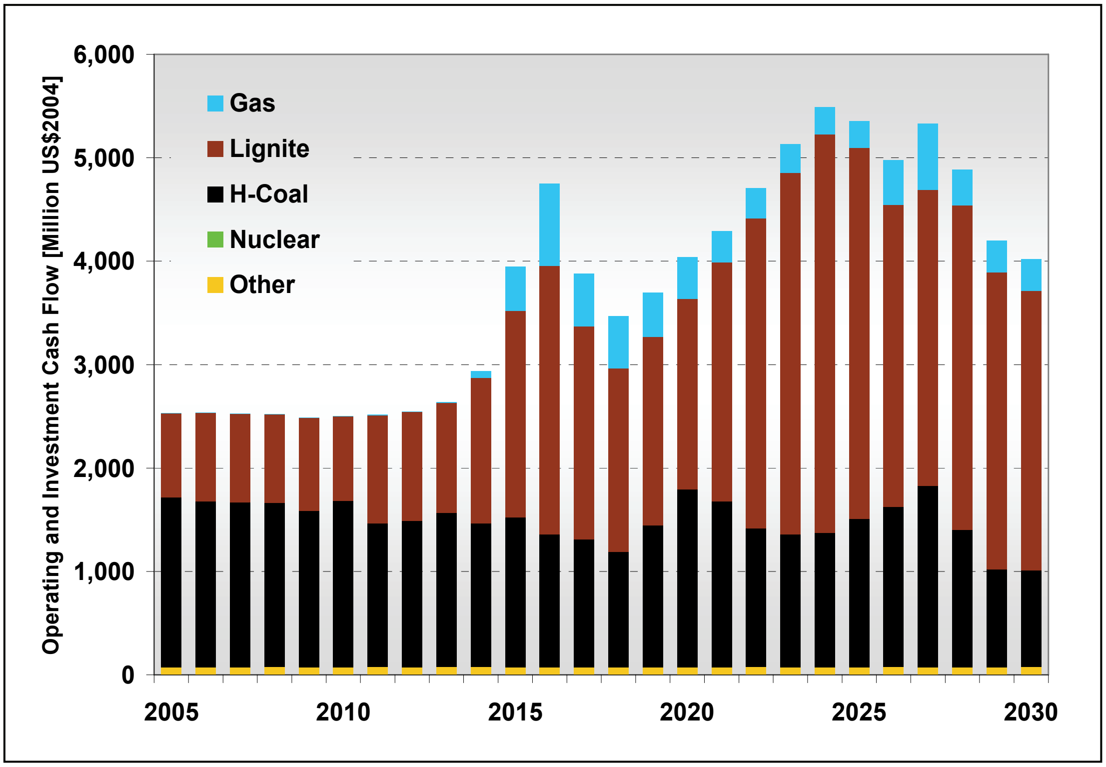

FIGURE 5.19 Zero Carbon Cost Case, Operating and Investment Costs (2005–2030) [Million $ USD 2004]

APPENDIX 6
METHODOLOGY, ASSUMPTIONS, AND RESULTS OF THE EMCAS ANALYSIS

6.1 METHODOLOGY

The Electricity Market Complex Adaptive Systems (EMCAS) was developed by Argonne National Laboratory (ANL) for the analysis of restructured electricity markets. It is designed for use both in regional U.S. markets and markets in other countries that are undergoing restructuring. The EMCAS model is the latest and most advanced tool in Argonne's suite of power systems analysis software. EMCAS uses a novel agent-based modeling approach to simulate the operation of today's complex power systems. EMCAS can be used as an "electronic laboratory" to probe the possible operational and economic impacts on the power system of various external events. Market participants are represented as "agents" with their own set of objectives, decision-making rules, and behavioral patterns. The EMCAS formulation can be described in terms of three main components: agents, interaction layers, and planning periods. The agents represent the participants in the electricity market. The interaction layers represent the environment in which the agents interact with each other. The planning periods represent the different time horizons in which the agents make decisions regarding their participation in the market. Figure 6.1 shows the agents and the interaction layers that are included in the EMCAS formulation.

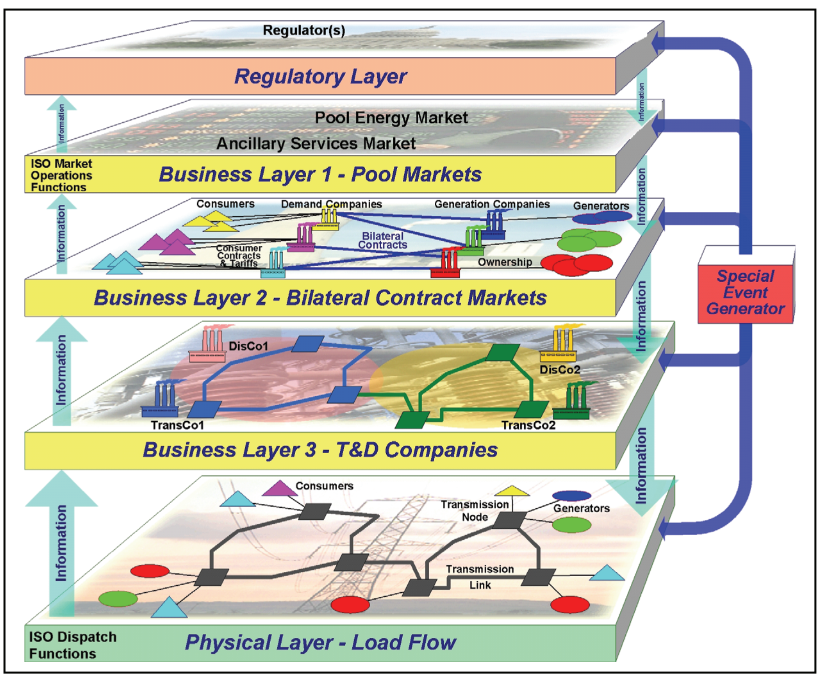

FIGURE 6.1 EMCAS Modeling Layers

Agents are modeled as independent entities that make decisions and take actions using limited and/or uncertain information available to them, similar to how organizations and individuals operate in the real world. EMCAS includes all the entities participating in power markets, including consumers, generation companies, transmission companies, distribution companies, demand companies, Independent System Operators (ISO) or Regional Transmission Organizations (RTO), and regulators.

In the physical layer, the transmission grid can be represented on a detailed bus and branch level to allow a full-scale load flow analysis. Here, the system operator dispatches the available generators to meet the load while maintaining the constraints and limitations of the transmission system. If needed, this representation can be simplified by developing a "reduced" transmission network. Several business layers are used to model the various forward markets (e.g., pool energy markets, bilateral contract market) where generation companies can buy and sell power. The operation of the transmission and distribution companies is included in a separate business layer. On the regulatory layer the user can set various operational and market rules. The special event generator can be used to examine the economic and operational impacts of system disturbances, such as component failures and outages. Table 6.1 shows the grid assumptions used by the study team.

EMCAS simulates the operation of power systems using an agent-based modeling approach. It computes electricity prices for each hour and each location in the transmission network. Electricity prices are driven by demand for electricity, cost of electricity production, the extent of transmission congestion, and external random or non-random events, such as unit outages or system disruptions. Model results include the economic impacts on individual companies and consumer groups under various operating scenarios.

With its unique combination of traditional and novel approaches, EMCAS provides the ability to capture and investigate the *complex interactions* between the physical infrastructures (generation and transmission) and the economic behavior of market participants that are a trademark of the newly emerging markets. With EMCAS being grounded in both established *engineering modeling* techniques as well as advanced quantitative *economic market principles*, the model is well positioned to address the strategic issues of interest to different market participants and stakeholders, such as:

- Short (daily) and long-term (multiple years) price forecasting of hourly LMPs (by node/zone/region and by hour or averaged over various time periods);

- Resource forecasting and asset valuation including unit-level hourly, daily, monthly, and annual operation, costs, revenues, and profits;

- Portfolio valuation to determine the market value of company portfolios consisting of a mix of contracts and generating resources;

- Volatility and risk analysis;

- Market design and development;
- Market monitoring and market power; and
- Transmission congestion.

EMCAS can also be used to perform a long-term expansion analysis for multiple generating companies under the conditions of deregulated electricity markets. The agent-based modeling approach facilitates the representation of different generating companies as independent and decentralized agents interacting with other agents operating in a complex, multi-dimensional environment. Each generating company makes independent investment decisions trying to optimize its own corporate utility function. The companies perform their decision-making with limited and/or uncertain information on the investment objectives and strategies of other market participants.

6.2 ASSUMPTIONS FOR THE EMCAS ANALYSIS

6.2.1 Grid Assumptions

TABLE 6.1 Basic Grid Assumptions

Parameter	Value	Comment
Base Year	2004	Used for model calibration purposes.
Actual analysis year	2017	EMCAS was run for the year in which the first nuclear unit is projected to come online by the WASP model.
Peak hours	9-21	From 9 a.m. to 9 p.m.
Summer months	4-9	From April through September.
Number of zones	5/16	Total of 16 — Five zones in Poland and 11 in the other neighboring countries, to simplify the EMCAS modeling (see Figure 6.2).
Pricing mechanism	Pay LMP	Pay locational marginal price.
Transmission losses	3%	Assumed standard average transmission losses
Transmission grid configuration and characteristics	various	Original bus-level load-flow data came from PSE-Operator. This was processed using a load-flow model into zonal grid characteristics for input into EMCAS.
Chronological loads for analysis year	Hourly load values	System-level loads for Poland came from PSE-Operator. Polish zonal loads were calculated based on additional information from EMA; loads in other countries came from respective system operators.

6.2.2 Grid Representation

Once part of the IPS (Interconnected Power Systems of the Soviet Union and Warsaw Bloc countries) and CENTREL (the coordinated power systems of Poland, the Czech Republic, Slovakia, and Hungary), Poland is now fully integrated into the European UCTE (Union for the Coordination of Transmission of Electricity) system. Besides the interconnections with other UCTE members (Germany, the Czech Republic, and Slovakia), Poland also maintains links with Ukraine and Belarus. There is also a high-voltage DC link to Sweden, which is not a member of UCTE. As of the year 2004, the Polish power grid consists of one 750 kilovolt (kV) line with the length of 114 kilometers (km), about 4,832 km of 400 kV lines, and about 7,895 km of 220kV lines. There are also 94 high-voltage substations with 166 transformers.

The study team used EMCAS to simulate the Polish power grid as well as its interconnections with neighboring countries. The team constructed five zones or hubs in the model, representing five Regions in Poland (Northern, Western, Central, Eastern, and Southern); it also included 12 other major connection hubs from Sweden, Italy/Switzerland, Germany North, Germany South, Austria, Czech Republic, Hungary, Slovakia, Romania and Southeast Europe (SETSO), Ukraine, Belarus, and Lithuania (see Figure 6.2). Each zone or hub represents an area with corresponding electricity generation and demand, and is represented as a node in the EMCAS network (grey and black circles). Thermal generators are represented by red circles and renewable generators are shown as green and blue circles. The links that connect nodes with other nodes represent the aggregate power transfer capabilities among the regions.

The team ran EMCAS for December 2017 – the peak month in the year that the WASP system expansion analysis determined as the online year for the first new nuclear units. Given the supply and demand situation, and the generation costs in each of the zones, the EMCAS model estimated zonal generations, power transfers across zones, and hourly locational marginal prices (LMPs) in each zone. LMPs represent the cost of supplying the next MW of load at a specific location and are used in many markets for congestion management. Even in markets that use different pricing mechanisms, such as Poland, LMPs can be calculated to reveal the value of locating new generation, upgrading transmission, or reducing power consumption. As such, LMPs can be taken as a proxy for the economic strain on the grid.

EMCAS was executed for a baseline run and six alternative scenarios (i.e., placing new nuclear capacity in one of five zones in Poland, or importing equivalent nuclear-generated power from Lithuania). For the scenario analyzing imports from Lithuania, the team assumed that a new 400-kV transmission line will be constructed and in operation by 2017. The power transfer capability of this new transmission link, assuming a 2-circuit line, was estimated at 2,000 MW. The results of the baseline analysis and six alternative scenarios were used to identify the location in the model grid configuration for the first nuclear units that would provide the largest benefit to the Polish system. Benefits were measured in terms of changes of average zonal LMPs in Poland in December 2017 with and without nuclear.

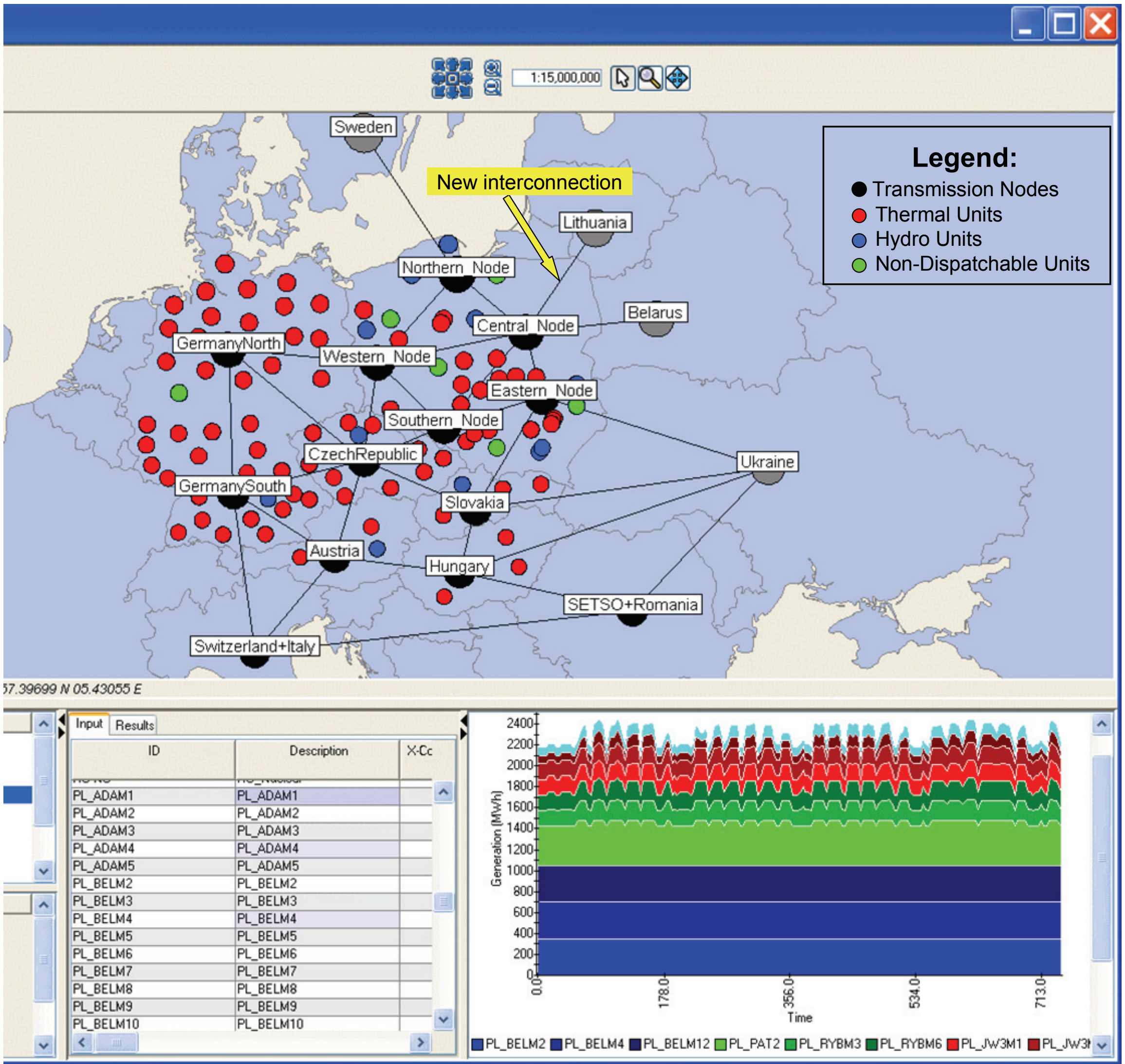

FIGURE 6.2 EMCAS Modeling Representation of the Polish Power Grid and Interconnections with Neighboring Systems

6.3 RESULTS

The study found that the Northern Region had the least amount of reserve margin in December 2017 without any new nuclear plants (see Table 6.2). The Northern Region reserve margin improves significantly if two new nuclear units were sited there (see Table 6.3). The LMPs by zone in December 2017 are shown in Table 6.4 both without nuclear and with nuclear being introduced. Both average LMP price reduction and average monthly price volatility by zone in December 2017 are shown in Tables 6.5 and 6.6. Based on the improvements in reducing price volatilities, the early plants should be sited in the Northern Region of the country in the vicinity of Gdańsk and in the Western Region of the country in the vicinity of Poznań to address the shortage of generating capacity in those regions in Poland (see Figures 6.3 and 6.4). Based on information obtained by the study team, no grid reinforcements would be needed for the site near

Gdańsk. The international press has reported that sites under consideration for a new nuclear plant include Gryfino and Klempicz near Poznań. The team also found that importing nuclear power from Lithuania would provide some economic relief (with benefits of $15.54/MWh).

TABLE 6.2 Reserve Margins by Zone without New Nuclear Units

Zone	Generating Capacity Thermal (MW)	Hydro (MW)	P-S (MW)	CHP (MW)	Total (MW)	Peak Load Dec 2017 (MW)	Reserve Margin (%)
Northern	0	319	680	883	1882	3931	-59.21
Western	6109	0	52	1149	7310	4936	48.10
Central	4810	24	0	1958	6792	6198	9.58
Eastern	4078	0	203	321	4602	3035	51.63
Southern	4874	363	500	1013	6750	6520	3.53
Poland Total	**19871**	**706**	**1435**	**5324**	**27336**	**24620**	**11.03**

SG30704

TABLE 6.3 Reserve Margins by Zone with New Nuclear Units in Northern Zone

Zone	Generating Capacity Thermal (MW)	Hydro (MW)	P-S (MW)	CHP (MW)	Total (MW)	Peak Load Dec 2017 (MW)	Reserve Margin (%)
Northern	3000	319	680	883	4882	3931	24.19
Western	6109	0	52	1149	7310	4936	48.10
Central	4810	24	0	1958	6792	6198	9.58
Eastern	4078	0	203	321	4602	3035	51.63
Southern	4874	363	500	1013	6750	6520	3.53
Poland Total	**22871**	**706**	**1435**	**5324**	**30336**	**24620**	**23.22**

SG30705

TABLE 6.4 Average Locational Marginal Price by Zone in December 2017 for Different Locations of Nuclear Power Plant

Zone	Without Nuclear	Northern Zone ($/MWh)	Western Zone ($/MWh)	Central Zone ($/MWh)	Eastern Zone ($/MWh)	Southern Zone ($/MWh)	Lithuania ($/MWh)
North	227.96	25.45	30.24	243.19	205.44	142.30	230.96
West	125.92	24.69	23.99	97.67	90.15	66.05	95.29
Central	45.87	25.83	24.59	22.55	26.15	25.15	23.92
East	40.36	26.49	26.45	30.58	30.61	28.83	30.88
South	51.67	26.27	26.24	39.74	38.81	33.72	39.63
Poland	**91.86**	**25.74**	**26.04**	**78.39**	**71.52**	**54.78**	**76.31**

SG30706

TABLE 6.5 Average Locational Marginal Price Reduction by Zone in December 2017 for Different Locations of Nuclear Power Plant

Zone	Without Nuclear	Northern Zone ($/MWh)	Western Zone ($/MWh)	Central Zone ($/MWh)	Eastern Zone ($/MWh)	Southern Zone ($/MWh)	Lithuania ($/MWh)
North	0.00	202.51	197.72	-15.23	22.52	85.66	-3.00
West	0.00	101.23	101.94	28.25	35.77	59.87	30.63
Central	0.00	20.04	21.28	23.32	19.72	20.72	21.95
East	0.00	13.87	13.91	9.78	9.75	11.53	9.48
South	0.00	25.40	25.43	11.93	12.86	17.95	12.04
Poland	**0.00**	**66.12**	**65.82**	**13.47**	**20.34**	**37.07**	**15.54**

SG30707

TABLE 6.6 Average Monthly Price Volatility Index by Zone in December 2017 for Different Locations of Nuclear Power Plant

Zone	Without Nuclear	Northern Zone (%)	Western Zone (%)	Central Zone (%)	Eastern Zone (%)	Southern Zone (%)	Lithuania (%)
North	621.10	7.49	47.56	618.39	570.95	356.68	688.61
West	289.11	5.88	34.30	278.21	229.43	143.89	283.27
Central	274.60	2.55	3.09	61.71	65.32	5.58	41.10
East	93.09	1.60	4.19	24.67	38.07	16.16	26.35
South	115.37	1.73	10.43	63.70	68.23	38.91	66.02
Poland	**213.29**	**3.02**	**26.18**	**201.95**	**173.78**	**111.15**	**207.29**

SG30708

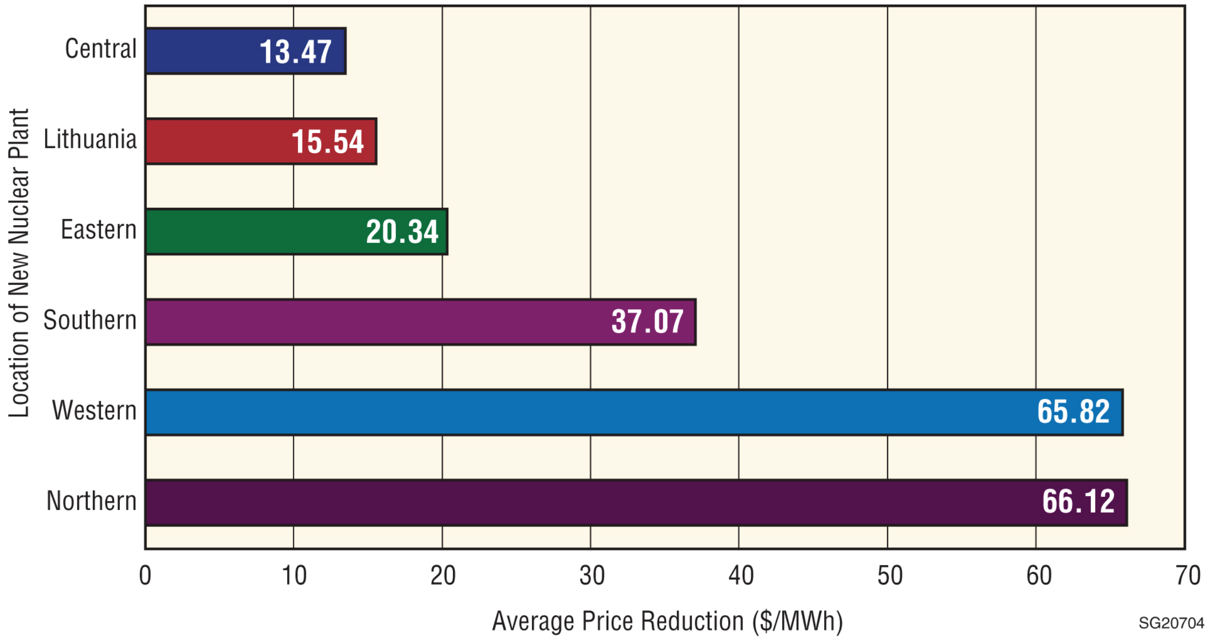

FIGURE 6.3 LMP Price Reductions

FIGURE 6.4 Potential Sites for New Nuclear Plants in Poland

Decision and Information Sciences Division
Argonne National Laboratory
9700 South Cass Avenue, Bldg. 900
Argonne, IL 60439-4832

www.anl.gov

A U.S. Department of Energy laboratory
managed by UChicago Argonne, LLC