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Comparative studies of energy supply options in Poland for 1997–2020

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FOREWORD

Poland depends heavily on coal to satisfy national demands for electricity. Currently, over 90% of electricity generation is produced by coal fired power plants. Because of the large dependence on coal and environmental impacts of large-scale coal combustion the country looks for a more diversified energy mix.

As ways of diversification, Poland is considering the expanded role of natural gas and, potentially, nuclear power in the future energy mix.

This publication describes the analysis of several diversification options for the Polish energy sector conducted by a national team in the framework of an IAEA Technical Co-operation project implemented in 1999–2000. The project provided a set of proven IAEA methodologies and tools that was utilized for a comprehensive analysis and comparison of the options including their economic competitiveness and environmental impacts.

The publication is intended primarily for senior experts and technical staff in governmental organizations, research institutes, industries and utilities, who are in charge of technical analysis or decision making related to long term energy and power supply options.

The report was prepared in 2001 by the staff of the Energy Market Agency (EMA, Warsaw, Poland) that was the leading Polish organization in carrying out the study. The IAEA wishes to express its gratitude to all Polish experts who participated in the preparation of the report. Special thanks are due to A. Kerner, who led the technical staff of EMA through the whole project, B. Hamilton (Adica Consulting, USA), who managed the project as the IAEA Technical Officer in 1999–2000, and T. Veselka (Argonne National Laboratory, USA), who supported the study through several expert missions to Poland and contributed extensively to the report, in particular with respect to the application of the GTMax model. The responsible IAEA officer for this publication was S. Kononov of the Planning and Economic Studies Section, Department of Nuclear Energy.

CONTENTS

0. SUMMARY

0.1. Study background, objectives, and organization

The Technical Co-operation (TC) Project for Poland *"Comparative Studies on Natural Gas and Nuclear Power"* was implemented in 1999–2000 by a national team with support of the International Atomic Energy Agency (IAEA). The principal objective of the project was to assess economic competitiveness and environmental impacts of different energy options, including natural gas and nuclear power. The project was carried out in parallel with the preparation of a Governmental document *"Energy Policy Guidelines till 2020"* and its main attachment "*Long-term Energy Demand and Supply Forecast till 2020"*. These documents were prepared using project results and published in February 2000.

The Energy Market Agency (EMA) was the national counterpart for the project. It provided the overall co-ordination among the participating organizations. The IAEA's assistance consisted of the release of energy models to Poland and expert missions.

A project Steering Committee was established in order to formulate guidelines for the energy options to be considered and to validate project documents. The Steering Committee included representatives of the Ministry of Economy, the Polish Power Grid Company, the Polish Oil and Gas Company, the Economic Association of Polish Power Plants, the Polish Association of Electricity Transportation and Distribution, the Polish Association of Public CHP Plants, the Association of Brown Coal Producers, and the "Polish Oil" Company.

The overall scope of the project is illustrated in Fig. ES-1. By implementation, the study can be divided into two distinct parts:

1. An analysis of the overall energy sector with a long-term forecast of energy demand till 2020 (formulation of energy demand projections, application of WASP, BALANCE, IMPACTS);
2. Partial analyses of the electric energy sector (application of GTMax and FINPLAN[1]).

The first part, which was most relevant to the preparation of the mentioned Governmental policy documents, was implemented in much more detail than the second one, also because the second part required application of new models (FINPLAN, GTMax) released by the IAEA to this project on a pilot basis.

0.2. Country background

A program of economic reforms was launched in Poland at the beginning of the 1990s. It resulted in severe economic contraction in 1990–1991. However, starting 1992 a positive growth of the gross domestic product (GDP) has been observed.

Poland has considerable coal resources: some 100 billion tonnes of hard coal and 16 billion tonnes of lignites. For energy supply, coal has always been the dominating resource, accounting for about 95% of total energy production and over 70% of total energy consumption. The coal restructuring programme, introduced in 1996 and amended in 1998, lays down the strategy for the sector for the period 1998–2005. Its aim is to eliminate the remaining subsidies and make the industry profitable by 2002.

[1] Due to the lack of time, financial analysis with FINPLAN was very limited.

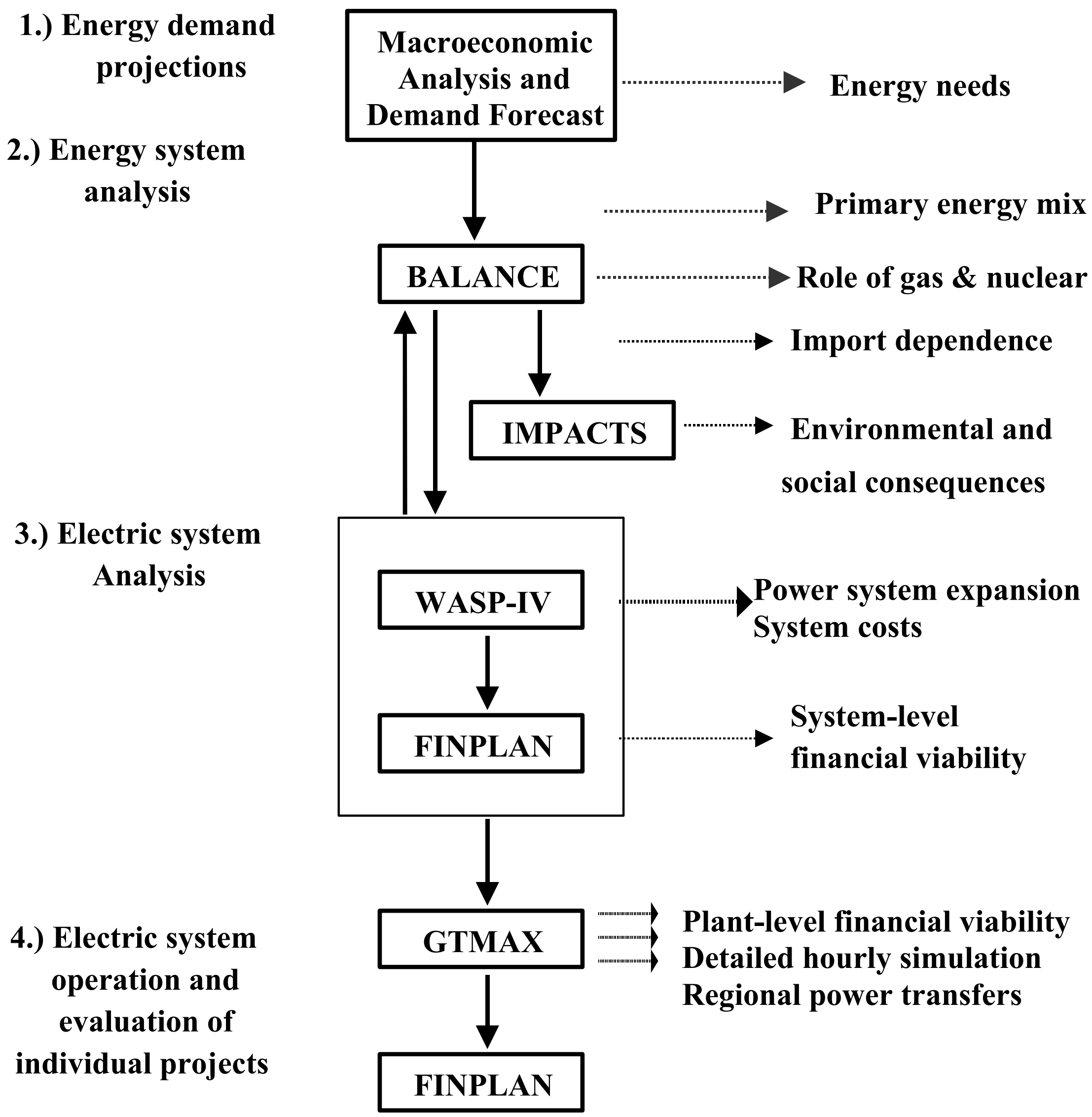


FIG. ES-1. Analytical scope of the study.

The development of electricity generation in Poland is shown in Table ES-1. In 1997, the installed generation capacity in Poland was ~29 GWe. Over 98% of the electricity generated comes from thermal generation (hard coal, lignite, natural gas, oil), mostly on coal (96.8%), the remaining part being hydroelectric generation.

In the past, Poland ranked among the most polluted countries in Europe. With the political changes since 1989, environmental issues have taken on greater importance. As a result, there are notable achievements, see Fig. ES-2. Further efforts are required, however.

TABLE ES-1. Installed generation capacity (GWe), electricity generation and consumption (in billion kW·h) in Poland, 1988–1997

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Hydroelectric	1.98	1.98	1.98	1.85	1.92	2.04	2.04	2.05	2.05	2.05
Thermal	28.13	28.95	28.77	28.85	29.07	26.62	27.08	27.59	27.42	27.66
Wind/Biomass	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	<0.01
Total Capacity	30.11	30.92	30.75	30.70	30.98	28.66	29.13	29.64	29.46	29.70
Net Generation	136.2	137.1	128.5	127.2	125.4	126.4	127.8	131.2	135.2	134.8
Net Consumption	131.1	129.3	118.5	115.7	112.3	115.1	116.2	119.3	122.6	123.2
Imports	12.5	12.1	10.4	6.7	4.8	5.6	4.6	4.4	4.8	5.4
Exports	8.0	10.3	11.5	9.3	9.1	8.0	7.2	7.2	7.9	7.5

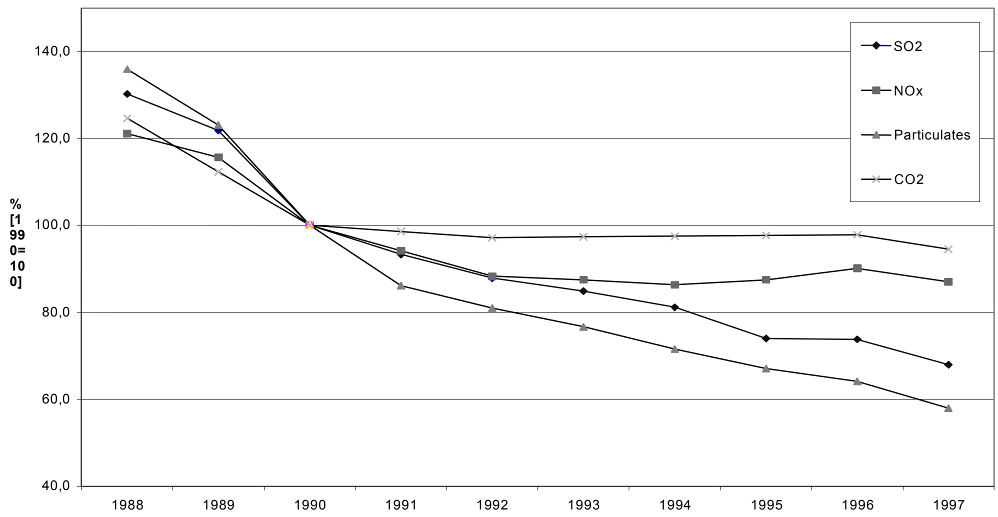


FIG. ES-2. Air pollutant emission indices in 1988–1997 (1990 = 100).

0.3. Assumed macro-economic scenarios

The energy demand projection is based on three macroeconomic scenarios for the period up to 2020 entitled 'the Survival Scenario', 'the Reference Scenario', and 'the Progress-Plus Scenario', see Table ES-2. They were prepared by the Institute of Development and Strategic Studies (IRiSS) and the Polish Foundation of Energy Efficiency (FEWE).

TABLE ES-2. Selected macroeconomic and energy indices

YEARS		1997	2005	2010	2015	2020
Population (for Survival and Reference), mln		38.66	39.26	39.93	40.32	40.34
Population (for Progress-plus), mln		–	38.63	38.79	39.00	39.00
Available labour force, mln		17.85	18.10	18.35	18.25	18.40
Energy intensity of GDP, kgoe/zł'95	SURVIVAL	0.309	0.253	0.237	0.216	0.193
	REFERENCE		0.212	0.181	0.158	0.140
	PROGRESS-PLUS		0.199	0.155	0.124	0.102
Electricity intensity of GDP, kW·h/zł'95	SURVIVAL	0.405	0.386	0.384	0.365	0.348
	REFERENCE		0.334	0.311	0.288	0.281
	PROGRESS-PLUS		0.309	0.260	0.221	0.199

YEARS		1997–2005	2006–2010	2011–2015	2016–2020
Average annual GDP growth, %	SURVIVAL	2.4	1.8	2.3	2.7
	REFERENCE	4.8	3.7	3.4	3.2
	PROGRESS-PLUS	5.7	6.3	5.5	5.1
Population income growth, %	SURVIVAL	2.4	1.9	1.9	2.7
	REFERENCE	5.1	3.7	3.4	3.2
	PROGRESS-PLUS	6.7	5.3	5.1	4.5

0.4. Analytical methodologies and tools

Methodologically, the following five areas have been addressed, see also Fig. ES-1:

- Projection of energy demand (with national models);
- Long-term analysis of the power system (with the WASP model);
- Long-term analysis of the energy system (with the ENPEP package);
- Assessment of environmental impacts of energy supply and use (with the IMPACTS module of the ENPEP package);
- Short-term analysis of the power system (with the GTMax model).

0.4.1. Projection of energy demand

Energy end-use projections were performed simultaneously for final energy demand (top-down approach), and useful energy demand forecast (bottom-up approach). Both methods were based on international statistical data, since historical data for Poland could not be applied to the simulation of a future market economy. Consistency between the both approaches was ensured by comparing the results and reiterating as necessary.

0.4.2. Long-term analysis of the power system

Long-term analysis of the Polish power system was conducted with the ELECTRIC module of the Energy and Power Evaluation Program (ENPEP). The ELECTRIC module is a microcomputer version of Wien Automatic System Planning Package (WASP). WASP determines the capacity expansion path that leads to the minimum net present value of the total system costs (investment, operation, fuel, unserved energy, etc.) over the study period subject to load requirements, system reliability constraints, minimum and maximum reserve margins, and implementation feasibility. It utilises probabilistic simulation of system operation and dynamic programming for optimization.

The following technologies were considered as WASP expansion candidates:

TABLE ES-3. Expansion candidates for power generation

Hard coal fired:	800 MW Advanced Pulverised Fuel plant with wet FGD installation 300 MW Integrated Gasification Combined Cycle plant (IGCC) 200 MW Pressurised Fluidised Bed Combustion plant (PFBC)
Lignite fired:	800 MW Advanced Pulverised Fuel plant with wet FGD installation
Natural gas fired:	165 MW Gas Turbine peaking plant 480 MW Combined Cycle Gas Turbine plant (CCGT)
Nuclear fuel fired:	1000 MW Pressurised Water Reactor plant.

Small new hydro plants were considered only in a case assuming promoting the use of renewable energy sources. In addition, some gas-fired CHP plants were also modelled as new distributed generation sources (i.e., independent power producers).

0.4.3. Long-term analysis of the energy system

Figure ES-3 shows the three modules of the ENPEP package that were used for energy system analysis. The focal point of the modelling system is the BALANCE module. Its major function is to simulate energy markets such that all future energy demands are satisfied.

As input data, BALANCE requires (apart from the demand projections) detailed information on the electric sector. In particular, an expansion plan (i.e., capacities and availability dates for new units) is needed. The new capacity requirements are determined by the ELECTRIC module and transferred to BALANCE. Since fuel prices (used in electric sector) are dependent on the generating capacity mix and resultant fuel consumption, iterations must be performed until the BALANCE and ELECTRIC modules converge.

0.4.4. Assessment of environmental impacts of energy supply and use

Energy flows obtained in BALANCE are input into IMPACTS module that computes environmental emissions from energy extraction, conversion, and consumption on the basis of the BALANCE energy flows and user-entered emission factors.

0.4.5. Short-term analysis of power system operation

The Generation and Transmission Maximization (GTMax) model was used for this analysis. It simulates the dispatch of electric generating units and the economic trade of energy among utility companies using a network representation of the power grid. Generation and energy transactions serve electricity loads that are located at various locations throughout the simulated region. Links and transformers connect generation and energy delivery points to load centres. Electricity loads are satisfied, curtailed via contractual agreements, or not served due to a generator supply shortage or because of transmission limitations.

The objective of GTMax is to maximize the net revenues of power systems by finding a solution that increases income while keeping expenses at a minimum. The model computes and tracks hourly energy transactions, market prices, and production costs. Using a mixed integer linear programming (LP) approach, GTMax simultaneously solves the maximization objective for all hourly time steps in a weekly simulation period. The model can be run for all 52-weeks in a year or for selected weeks that are representative of a month or a season.

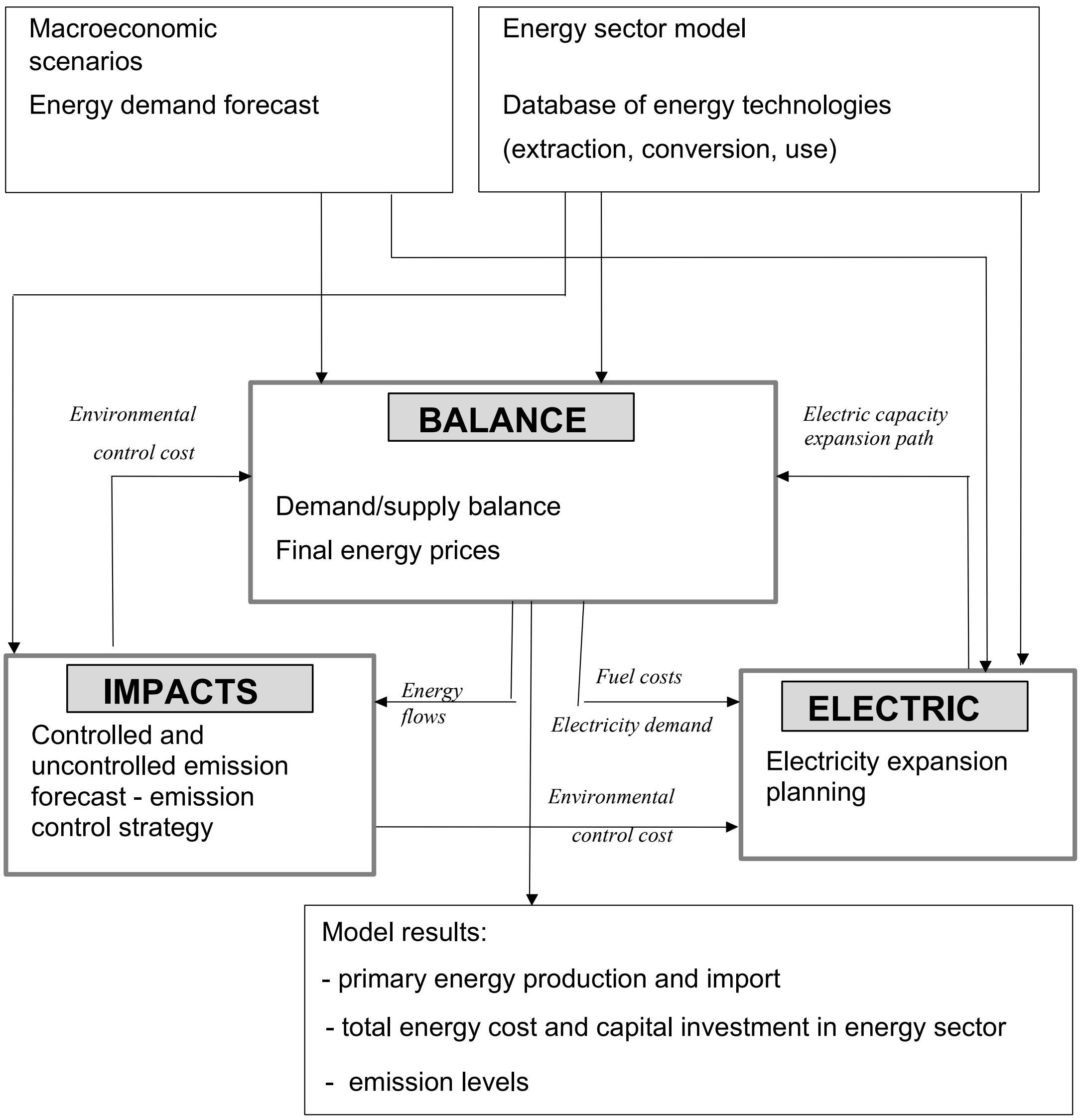


FIG. ES-3. Model input data, ENPEP modules and model results.

0.5. Projection of final energy demand

Results of the final energy demand projections are presented in Tables ES-4 and ES-5.

TABLE ES-4. Final energy demand by economic sector, Mtoe

Scenario	Economy Sector	1997	2005	2010	2015	2020
SURVIVAL	Manufacturing & Construction		28.8	29.4	30.0	30.5
	Transport		10.3	10.4	10.9	11.3
	Agriculture		4.9	5.0	5.2	5.3
	Services		4.1	4.3	4.5	4.8
	Households		19.7	20.0	20.1	20.3
	TOTAL		67.7	69.1	70.8	72.3
REFERENCE	Manufacturing & Construction	29.9	28.7	29.5	30.1	30.7
	Transport	9.9	10.5	10.8	11.6	12.4
	Agriculture	5.1	4.9	5.0	5.3	5.3
	Services	4.4	4.3	4.7	5.2	5.9
	Households	22.7	19.7	20.3	20.7	21.2
	TOTAL	72.0	68.1	70.3	72.9	75.6
PROGRESS-PLUS	Manufacturing & Construction		27.6	29.4	31.0	32.7
	Transport		11.0	12.2	13.7	15.6
	Agriculture		4.6	4.4	4.3	4.2
	Services		4.2	4.8	5.5	6.5
	Households		19.8	20.5	21.2	22.0
	TOTAL		67.2	71.3	75.6	80.9

TABLE ES-5. Final energy demand by energy carrier, Mtoe

SCENARIO	ECONOMY SECTOR	1997	2005	2010	2015	2020
SURVIVAL	COAL		17.0	16.0	15.4	15.0
	PETROLEUM PRODUCTS		19.2	18.9	19.2	19.6
	NATURAL GAS		12.4	14.7	16.2	17.1
	OTHER FUELS		4.3	4.2	4.2	4.2
	ELECTRICITY		9.5	10.6	11.7	13.0
	HEAT		5.3	4.6	4.0	3.4
	TOTAL		67.7	69.1	70.8	72.3
REFERENCE	COAL	24.6	16.8	16.0	15.4	14.9
	PETROLEUM PRODUCTS	16.8	18.8	18.9	19.6	20.4
	NATURAL GAS	10.1	12.9	15.3	16.8	17.5
	OTHER FUELS	5.0	4.3	4.2	4.2	4.2
	ELECTRICITY	8.1	9.9	11.5	13.3	15.6
	HEAT	7.4	5.2	4.2	3.5	3.0
	TOTAL	72.0	68.1	70.3	72.8	75.6
PROGRESS-PLUS	COAL		16.7	16.5	15.9	15.4
	PETROLEUM PRODUCTS		20.6	21.4	22.8	24.6
	NATURAL GAS		10.5	12.4	14.1	15.5
	OTHER FUELS		4.7	4.7	4.8	4.9
	ELECTRICITY		9.5	11.3	13.4	15.9
	HEAT		5.3	4.9	4.7	4.6
	TOTAL		67.2	71.3	75.6	80.9

The following conclusions can be drawn from the results:

— A relatively small (between 0 and 0.5%) annual increase of final energy demand (FED) is projected (Fig. ES-4). FED growth rates are lower than the corresponding GDP growth rates due to assumed increase in energy efficiency. In all scenarios, a 5–7% decrease of total energy demand is projected till the year 2005, and only thereafter a gradual rise of demand is observed. The overall increase of the total

FED in the period 1997–2020 under the Survival, Reference and Progress-Plus scenarios is 0.4%, 5% and 12%, respectively.

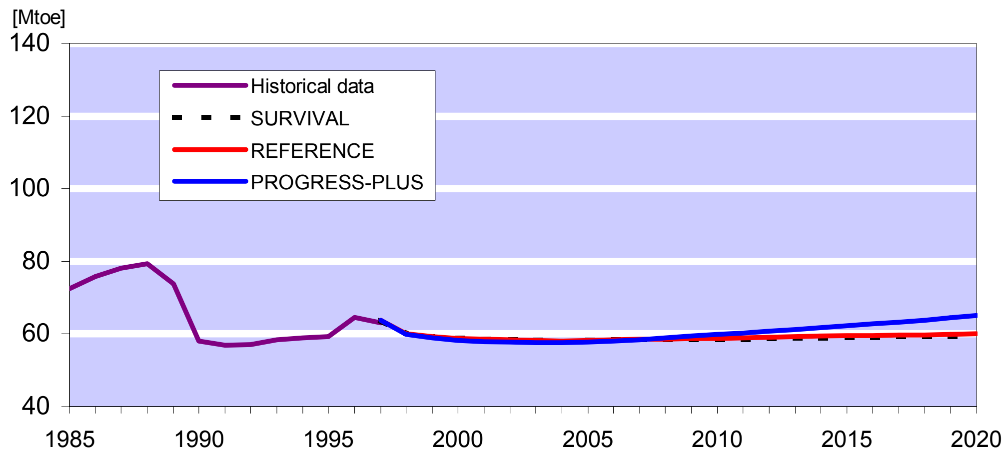


FIG. ES-4. Total final energy demand.

— A gradual change of structure of sectoral energy demand can be observed. The transport sector has the most significant increase in final energy demand (from about 13% in the Survival, through 25% in the Reference to over 50% increase in the Progress-Plus scenario). This transforms into a growing demand for petroleum products. Next to transport is the commercial sector, reflecting the increasing economic importance of services. In contrast, the energy demands in industry and the residential sector stagnate.

— There is a clear change in the structure of energy carriers. The demand for electricity grows in all sectors faster than the total energy demand (2–3%/a), see Fig. ES-5. This reflects a low initial level of electricity use, the growing standard of living, and the fact that electricity is not easily replaceable.

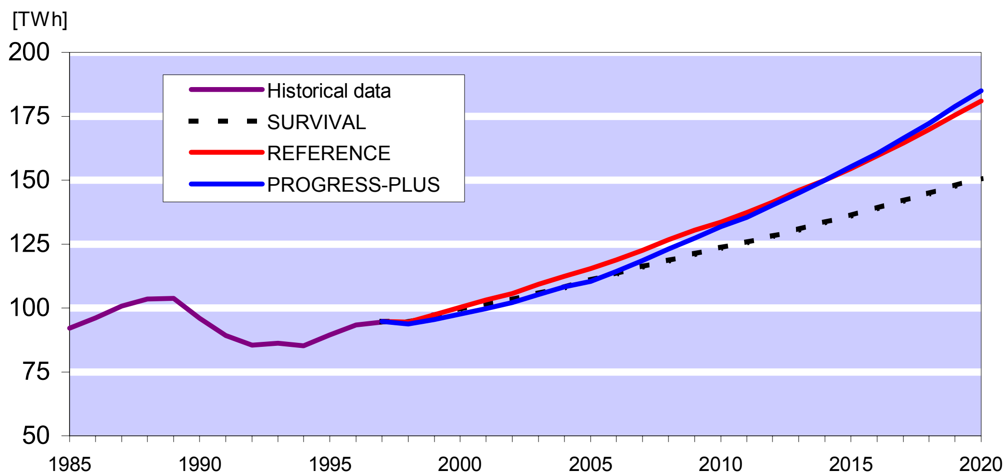


FIG. ES-5. Final electricity demand.

- Demands for petroleum products and natural gas are also expected to increase, although more moderately. In contrast, coal consumption diminishes steadily in all scenarios at an average annual rate of 2%, reflecting the decreasing coal availability.

- There is a marked decline in the use of district heat: an average annual drop of 2% in the Progress-Plus, and almost 4% in the Survival and Reference scenario. This happens mainly due to the declining demand for heat (because of more efficient use of energy), and increased local heat production.

0.6. Projection of primary energy demand

0.6.1. Assumptions

The assumed level of hard coal extraction was limited in accordance with the coal industry restructuring program as shown in Table ES-6.

TABLE ES-6. Hard coal extraction and export, Mt

	1998	2000	2002	2005	2010	2015	2020
Coal extraction	116	114	110	101	90	85	80
in which: Export	27	23	20	14	10	10	10

Lignite is presently the least expensive primary energy carrier used in Poland for electricity generation. The annual lignite production capacity until 2020 is estimated to be in the range of 60 to 70 million tons.

At present Poland has the following signed contracts for imported natural gas:

- Long-term contract with Russia – a steady increase from 2.9 billion m^3/year in the year 2000 to about 12.5 billion m^3 in the year 2010,
- Five-year contract for Norwegian gas – up to 0.5 billion m^3/year annually, starting in the middle of the year 2000, with a possible increase subject to future transportation pipeline capabilities,
- Annual contract for German gas – app. 0.5 billion m^3/year with a possibility of its extension over 15 year period,
- Annual contract with Ukraine for about 1 billion m^3/year.

There are also technical possibilities for modernisation of existing pipelines, allowing an increase of natural gas import from the western Europe to about 1.5 billion m^3/year. Thus, the guaranteed gas imports together with the domestic gas extraction assure about 20 billion m^3/year starting 2010. In addition, it was assumed that later an increase of gas import by several billion m^3/year would be feasible.

The existing oil transportation capacities significantly exceed the needs of domestic refineries and those of expected transits. Therefore, no such constraints were modelled.

Under the Progress-Plus scenario the fuel prices were set according to a 1998 IEA/NEA assessment. The assumed average annual price increase was: 0.3% for hard coal, 1% for natural gas, crude and fuel oil, and 0.1% for nuclear fuel. For the other two scenarios, the assumed average annual price growth rates were: hard coal – 1%, crude oil – 1.6%, natural gas and fuel oil – 2.2%, and nuclear fuel – 0.1%.

The weighted average price of lignite in 1997 was 11.3 USD (‘97)/t or 55.0 USD (‘97)/toe. The projected average annual price growth rate was 0.1%.

The discount rate was assumed 12% under the Survival and Reference scenarios, and 10% under the Progress-Plus scenario (more favourable economic conditions).

0.6.2. Results

0.6.2.1. Development of the power system

The projected trends in generation capacities are shown in Table ES-7. It shows that new public generation plants appear only after 2010. They are mainly combined cycle gas turbines (CCGT) and peaking gas turbine plants.

TABLE ES-7. Projected new generation capacity, MWe net

	SURVIVAL Scenario				
	1998–2005	2006–2010	2011–2015	2016–2020	**Total**
Distributed CHPP	1794	1699	1282	466	**5242**
Industrial CHPP – Gas fired	160	72	31	68	**330**
Public CHPP – Coal and gas fired	2438	606	994	470	**4508**
Public PP	0	0	810	5325	**6135**
Lignite-fired	*0*	*0*	*0*	*0*	***0***
Gas turbine	*0*	*0*	*330*	*1485*	***1815***
GTCC	*0*	*0*	*480*	*3840*	***4320***
	REFERENCE Scenario				
	1998–2005	2006–2010	2011–2015	2016–2020	**Total**
Distributed CHPP	1811	1860	1735	590	**5996**
Industrial CHPP – Gas fired	195	65	58	117	**434**
Public CHPP – Coal and gas fired	2438	606	994	470	**4508**
Public PP	0	0	2100	6935	**9035**
Lignite-fired	*0*	*0*	*0*	*3200*	***3200***
Gas turbine	*0*	*0*	*660*	*1815*	***2475***
GTCC	*0*	*0*	*1440*	*1920*	***3360***
	PROGRESS-PLUS Scenario				
	1998–2005	2006–2010	2011–2015	2016–2020	**Total**
Distributed CHPP	992	2750	2238	1059	**7039**
Industrial CHPP – Gas fired	313	40	151	225	**730**
Public CHPP – Coal and gas fired	2438	606	994	470	**4508**
Public PP	0	0	2100	6935	**9035**
Lignite-fired	*0*	*0*	*0*	*3200*	***3200***
Gas turbine	*0*	*0*	*660*	*1815*	***2475***
GTCC	*0*	*0*	*1440*	*1920*	***3360***

It is expected that large-scale combined heat and power plants (CHP) for district heating and industrial applications as well as small CHP applications have a large potential. The total share of CHP in 2020 (in terms of share of electricity production) is estimated at about 35% in

Survival and above 40% in Reference and Progress-Plus Scenario, a more than two-fold increase in comparison to 1997 level.

No nuclear power capacity is projected in any scenario over studied planning period. The reasons are: insufficient economic competitiveness of nuclear plants (due to high capital costs), availability of cheaper alternatives (natural gas in particular), and the absence of environmental motivation to use nuclear power (air emissions are decreasing significantly).

0.6.2.2. Pattern of primary energy mix

The primary energy demand (PED) projections by 2020 are presented in Table ES-8.

TABLE ES-8. Primary energy demand projections, Mtoe

Scenario	Energy carrier	1997	2005	2010	2015	2020
SURVIVAL	Hard coal		53.3	53.0	51.9	50.3
	Lignite		13.7	13.8	13.6	13.5
	Oil		20.4	20.2	20.8	21.1
	Natural gas		13.4	16.1	18.8	21.3
	Nuclear		0.0	0.0	0.0	0.0
	Renewable energy		5.3	5.5	5.7	5.9
	TOTAL		106.2	108.6	110.7	112.2
REFERENCE	Hard coal	60.0	52.4	50.8	50.5	49.3
	Lignite	13.5	13.7	13.9	13.6	13.5
	Oil	18.6	20.2	20.4	21.4	22.3
	Natural gas	9.8	14.6	18.0	20.5	24.0
	Nuclear	0.0	0.0	0.0	0.0	0.0
	Renewable energy	5.5	5.5	6.0	6.5	7.1
	TOTAL	107.3	106.4	109.1	112.4	116.2
PROGRESS-PLUS	Hard coal		49.1	51.0	50.9	49.6
	Lignite		13.7	13.8	13.6	13.5
	Oil		22.2	23.5	25.3	27.9
	Natural gas		12.9	15.1	18.1	22.6
	Nuclear		0.0	0.0	0.0	0.0
	Renewable energy		5.8	6.3	6.9	7.7
	TOTAL		103.7	109.7	114.7	121.3

Under all scenarios a decline of primary energy until 2005 is projected. This results from the assumed more rational use of energy. After 2005, a modest increase of PED is expected in all scenarios. The total PED growth in the planning period is 4.6%, 8.3% and 13% in the Stagnation, Reference and Progress-Plus scenario, respectively. Corresponding average annual growth rates are 0.2%, 0.36% and 0.55%.

For comparison, Fig. ES-6 the expected developments in total PED along with historical demand development (statistical data for the period 1985–1997). It is indicative that projected primary energy requirements in 2020, under all scenarios, are lower than the primary energy consumption in 1988.

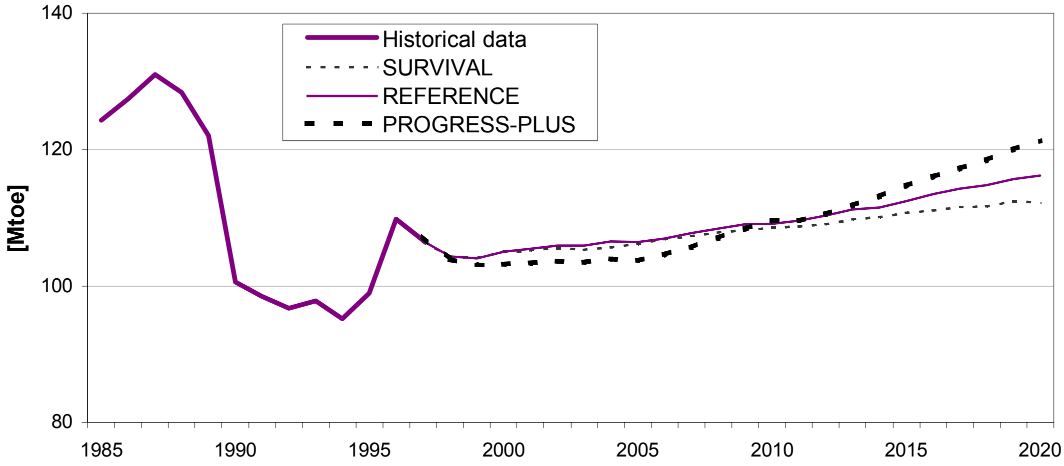


FIG. ES-6. Historical and projected primary energy demand.

The use of hard coal gradually diminishes, in accordance with the Government's policy (independently of scenario, the assumed hard coal production capacity is 80 million tonnes in 2020). The decline is highest in the Progress-Plus and lowest in the Survival scenario, since in the latter case an economy structure based on raw materials persists.

Requirements for crude oil and imported petroleum products also increase, mainly in the transport sector, following the expected increase in transport services.

In all scenarios, the share of natural gas increases strongly, especially in the power sector (small and medium size co-generation sources). The competitiveness of natural gas with respect to coal is based on its moderate prices, higher conversion efficiencies, and benign impact on environment. Gas demand more than doubles in 2020 compared to 1997. This means large gas imports, lowering the security of supply from the viewpoint of import dependency. On the other hand, the resulting larger fuel diversification has a positive impact on the security of supply. The increase in gas imports would require new investments in the transport infrastructure, which was taken into account in the analysis.

Due to limited technical potential and low cost-effectiveness, the currently low share of renewable energy sources will not change significantly and stay below 6.5%. Large additional policy efforts, including special promotional measures, would have to be taken, if the share of renewables in the overall energy mix is to be increased.

0.6.2.3. Indicators of energy supply sufficiency

For all scenarios, the energy and electricity use per capita in Poland remain below the expected average for the EU countries. Approximately a 30% difference between the indicators for Poland and those for the EU countries is projected for the year 2020.

0.6.2.4. Indicators of energy supply security

Two indicators were used to describe the energy supply security:

- energy self-sufficiency defined as domestic production/TPES ratio,
- diversification of primary energy supply.

As shown in Fig. ES-7, whereas currently Poland has a quite high index of energy self-sufficiency, a steady decline of this value is predicted over next two decades to about 60% in the year 2020, mostly due to large increases in gas imports, supported by continuing oil imports. Nevertheless, the self-sufficiency index of Poland would still be above the present average value for the EU countries, and much higher than, for instance, for Germany or France.

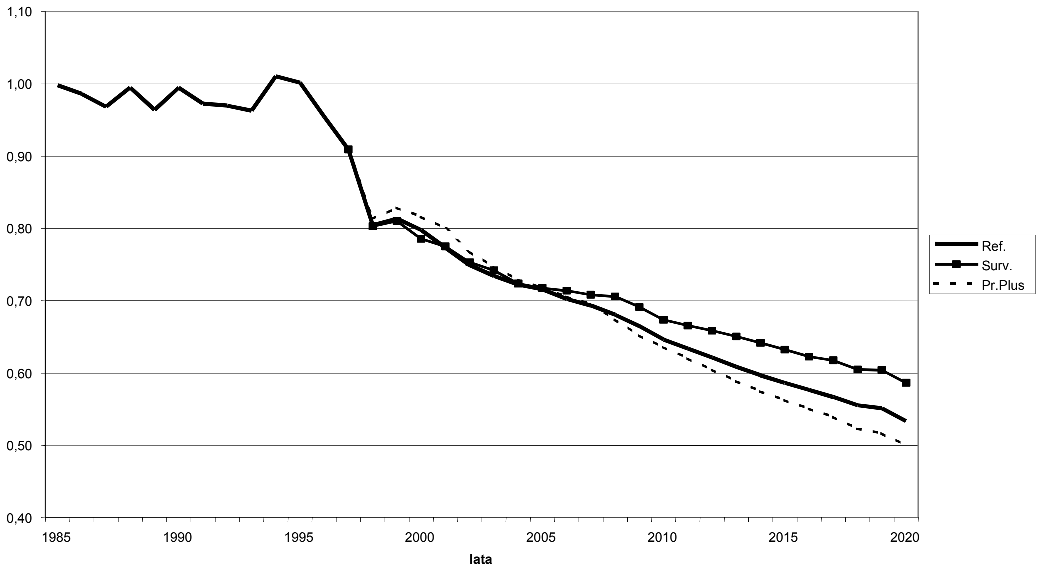


FIG. ES-7. Historical and projected energy self-sufficiency indices.

The so-called Stirling index was used as an indicator of energy supply diversity. It is higher if more energy carriers form the energy mix as well as if the share of different energy carriers is more uniform. If lignite and hard coal are defined as two independent energy carriers, the primary energy diversity index for Poland is close to the one in the neighbouring countries (Table ES-9).

TABLE ES-9. Stirling indices for Poland (1997) and some EU countries (1996)

France	UK	Germany	Poland	Denmark	Italy
1.35	1.32	1.52	1.26	1.20	1.01

By 2020, the Stirling index for Poland would grow to about 1.4. The smallest increase is in the Survival scenario, reflecting lower imports than in the two other scenarios. Projected gas imports, from the point of view of fuel diversification, are beneficial to the security of supply. On the other hand, large gas imports lower the security of supply where import dependency is concerned. For this reason, diversification of gas suppliers will be of great importance.

0.6.2.5. Energy prices for end-users

Table ES-10 summarises the projected prices of electricity, natural gas and district heat for households, under all scenarios. It shows that almost a two-fold increase of electricity prices is expected by the year 2020. The increase is the smallest in the Survival scenario (lowest level of new generating capacity), particularly in the first half of the planning period. A moderate rise of natural gas prices is predicted under all scenarios, the lowest increase however (only about 20% over whole study period) is in the Progress-Plus Scenario. Finally, a significant increase (about 45%) of district heat prices is projected in both Survival and

Reference scenario. In contrast, in the Progress-Plus scenario a slow but steady decrease of the heat price would occur, which is a consequence of assumed lower fuel price growth rates as well as an increased cogeneration.

The shown price increases should be viewed in the context of increasing incomes per capita expected in all scenarios, see Table ES-2.

TABLE ES-10. Projected energy price increases (relative to 1997)

Scenario	1997	2005	2010	2015	2020
	Electricity for Households				
SURVIVAL	100	129	135	159	181
REFERENCE	100	141	157	177	194
PROGRESS-PLUS	100	150	157	179	196
Scenario	1997	2005	2010	2015	2020
	Natural Gas for Households				
SURVIVAL	100	112	118	124	133
REFERENCE	100	112	119	125	134
PROGRESS-PLUS	100	105	110	114	119
Scenario	1997	2005	2010	2015	2020
	District Heat				
SURVIVAL	100	100	100	125	143
REFERENCE	100	103	120	136	147
PROGRESS-PLUS	100	91	91	90	90

0.7. Environmental impacts

The emissions of the major airborne pollutants (particulates, sulphur dioxide – SO_2, nitrogen oxides – NO_x, and carbon dioxide – CO_2) were computed with the IMPACTS module of ENPEP. Figures ES-8–ES-12 present projections for the major airborne pollutants in each of the three scenarios. Although some scenarios come out better than others, the emissions do not differ significantly across the scenarios. This is understandable, because the scenarios do not significantly differ in energy production by the worst pollution emitters — existing coal and lignite power plants, and small heating and co-generation stations.

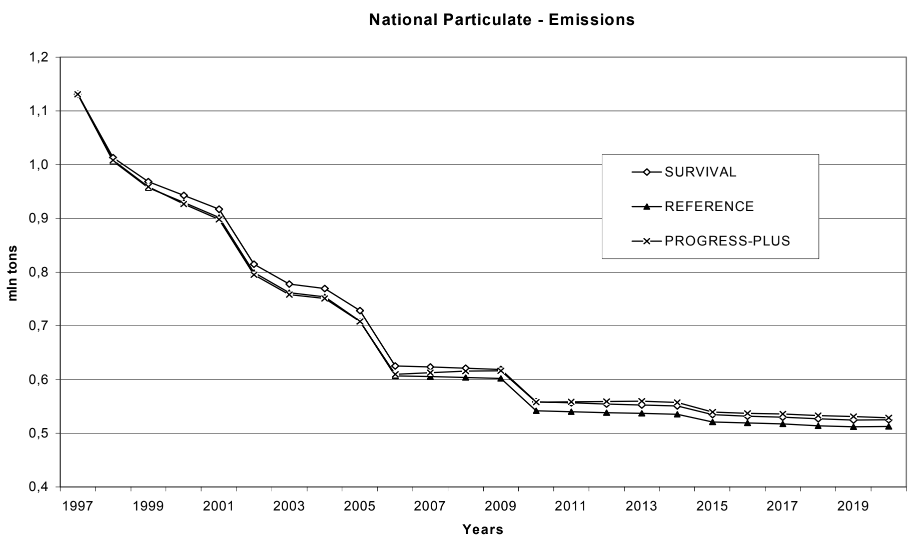


FIG. ES-8. Particulate emission projections.

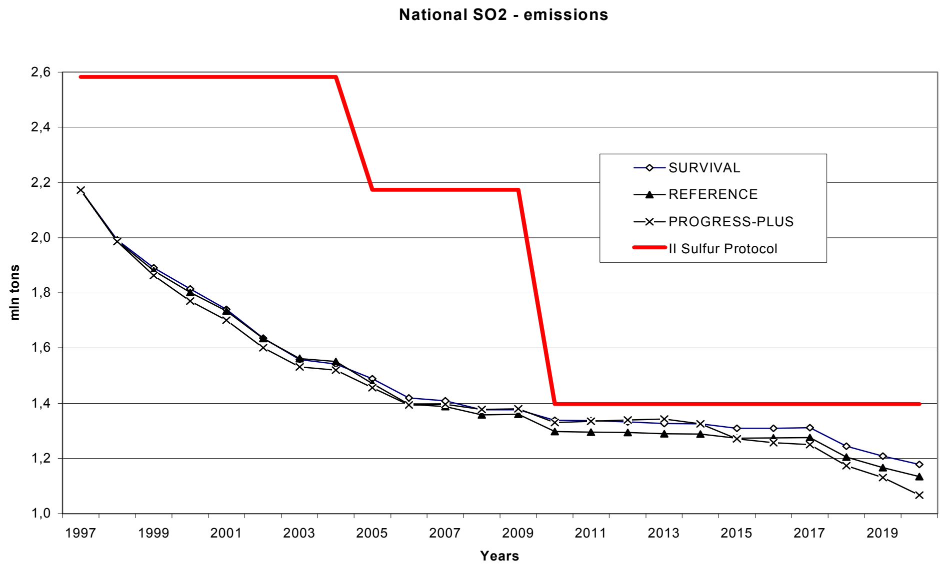


FIG. ES-9. Sulphur dioxide emission projections.

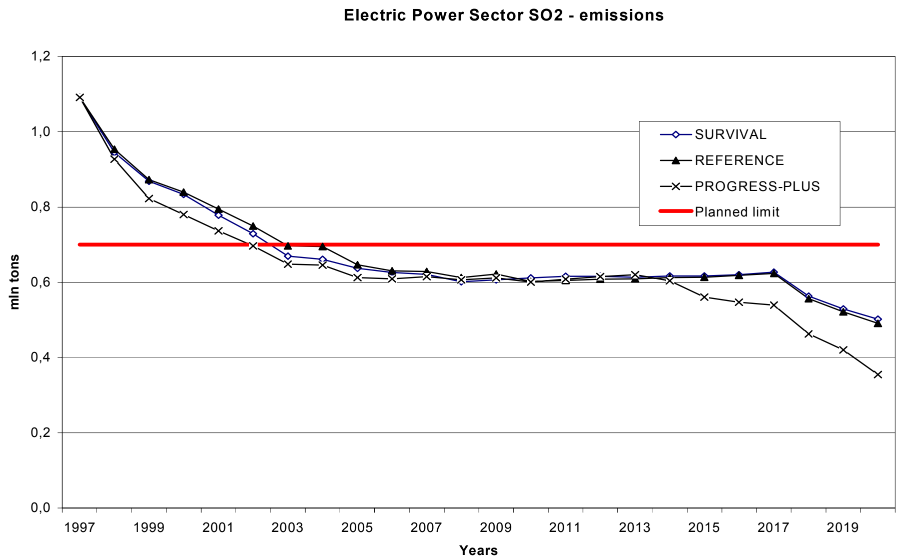


FIG. ES-10. Projections of sulphur dioxide emissions in electric power sector.

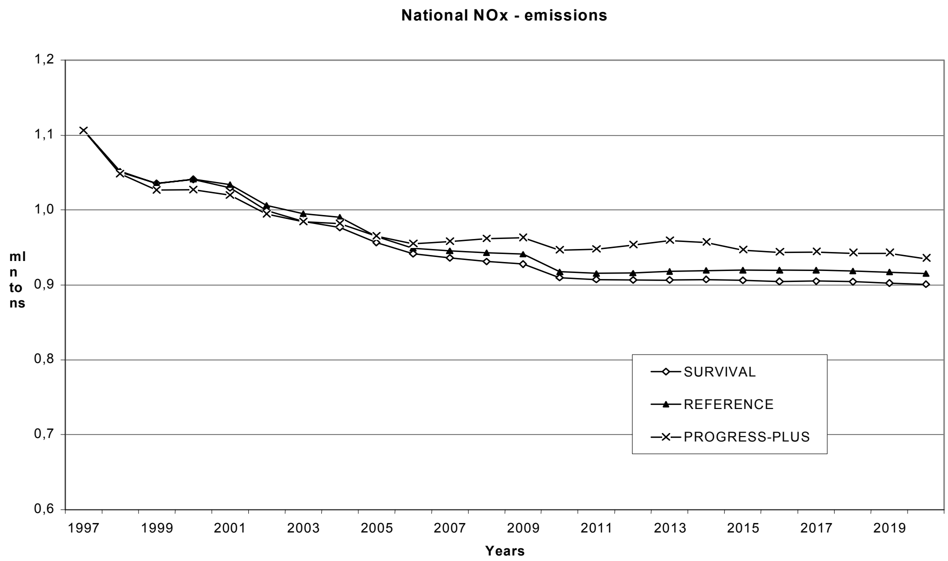


FIG. ES-11. Nitrogen oxides emission projections.

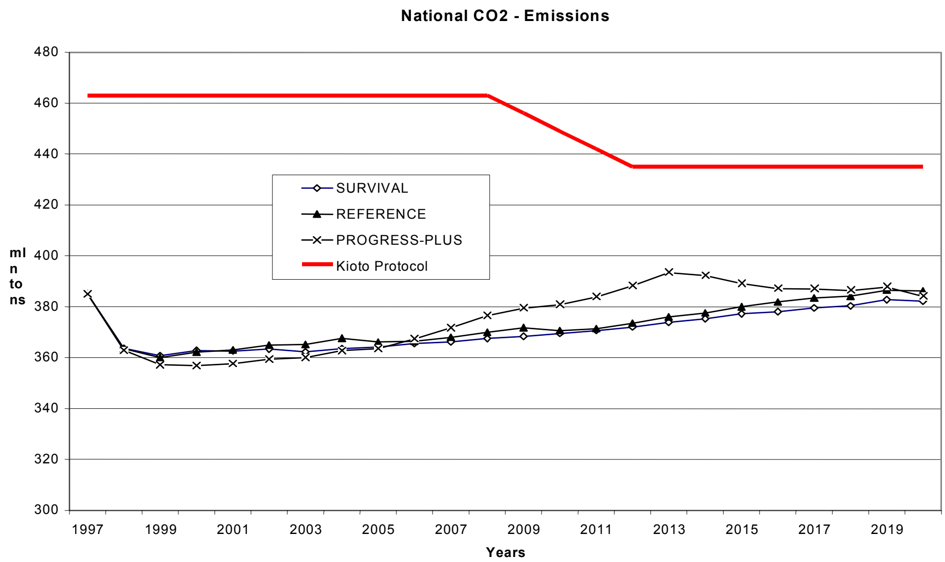


FIG. ES-12. Carbon dioxide emission projections.

There are presently two airborne pollutants, sulphur dioxide (SO_2) and carbon dioxide (CO_2), that Poland must reduce in accordance with its international obligations, namely:

— UN-ECE II Sulphur Protocol (Oslo 1994) — Reduction of SO_2 emissions by 37% in 2000, 47% in 2005 and 66% in 2010, compared to the 1980 level,

— UN FCCC (1992) and its Kyoto Protocol (1998) — Stabilisation of CO_2 emissions in 2000 and its reduction by 6% in 2008–2010 compared to the 1988 level.

The emission projections show the following:

— ***Projections of national particulate emissions***: A significant decline of particulate emissions, about 50% reduction by 2010, is observed in all scenarios. This is directly related to the assumption that all stationary sources burning fossil fuels would comply with the imposed new emission standards.

- ***Projections of national SO_2 emissions***: Despite a growing demand for fuels and energy, a steady decrease of sulphur dioxide emission over the whole study horizon is noticeable. The first two targets of the Second Sulphur Protocol (for the year 2000 and 2005) can be easily met. However, the next emission level, 1400 kt after 2010, might be harder to comply with. For this reason, successful realisation of all assumed measures on sulphur emissions reduction is important.

- ***Projections of SO_2 emissions in electric power sector***: Comparison of SO_2 emissions in the electric power sector with the cap of 0.7 million tonnes/year in 2010 shows that the ongoing modernisation program for existing power plants suffices to meet that goal. However, after 2010 a greater use of natural gas is necessary to prevent the subsequent growth of SO_2 emissions.

- ***Projections of national NOx emissions***: There is an initial decrease of NO_x emissions (by 2006) due to combustion improvement at coal-fired plants (change to fluidised combustion and low-NO_x burners) and to replacement of old motor vehicles by new ones. Afterwards, NO_x emissions remain stable or even start increasing due to growing road transportation. One should note that in November 1999, a new UN-ECE 'Gothenburg Protocol' was adopted, setting, among others, annual NO_x emission ceilings for Europe for 2010. According to this Protocol (if ratified), Poland would need to limit NO_x emissions below 880 thousand tons/year by 2010. Under the present assumptions this goal would not be met in any of the three scenarios.

- ***Projections of national CO_2 emissions***: Various strategies to reduce CO_2 emissions (energy conservation, increased efficiency in energy supply, cogeneration, fuel substitution, promotion of renewables) were considered in the analysis. Taking into account that CO_2 emissions in 1997 have already decreased by about 17% compared to 1988, the Kyoto Protocol (6% reduction in the period 2008–2010, compared to 1988 level) seems relatively easy to achieve. By 2010, Polish CO_2 emissions will level off at a rate 15–20% lower than in Poland's baseline year of 1988.

0.8. Analysis of short-term operation of the power market

0.8.1. Assumptions

An analysis of the Polish power system was used to investigate the potential role that small-scale combined heat and power (CHP) plants may play during a peak load situation. The economic value of CHP plants and the short-term financial gains that CHP owners may gain were also estimated via GTMax simulations. A candidate gas-fired CHP plant was located in the region with the highest economic cost of energy. A second object of the analysis was to estimate the potential for east-to-west power transfers across Poland. The

Polish Power Grid could potentially reap financially by purchasing energy from an adjoining power system to its east at a relatively low price and resell this energy to its west at a higher price. The Polish Power Grid Company could also wheel energy for a third party for a service fee.

The Polish power grid was modelled as a set of interconnected power regions or power pools. As shown in Fig. ES-13, there are a total of five regions that consist of the following: (1) Central, (2) Eastern, (3) Southern, (4) Western, and (5) Northern.

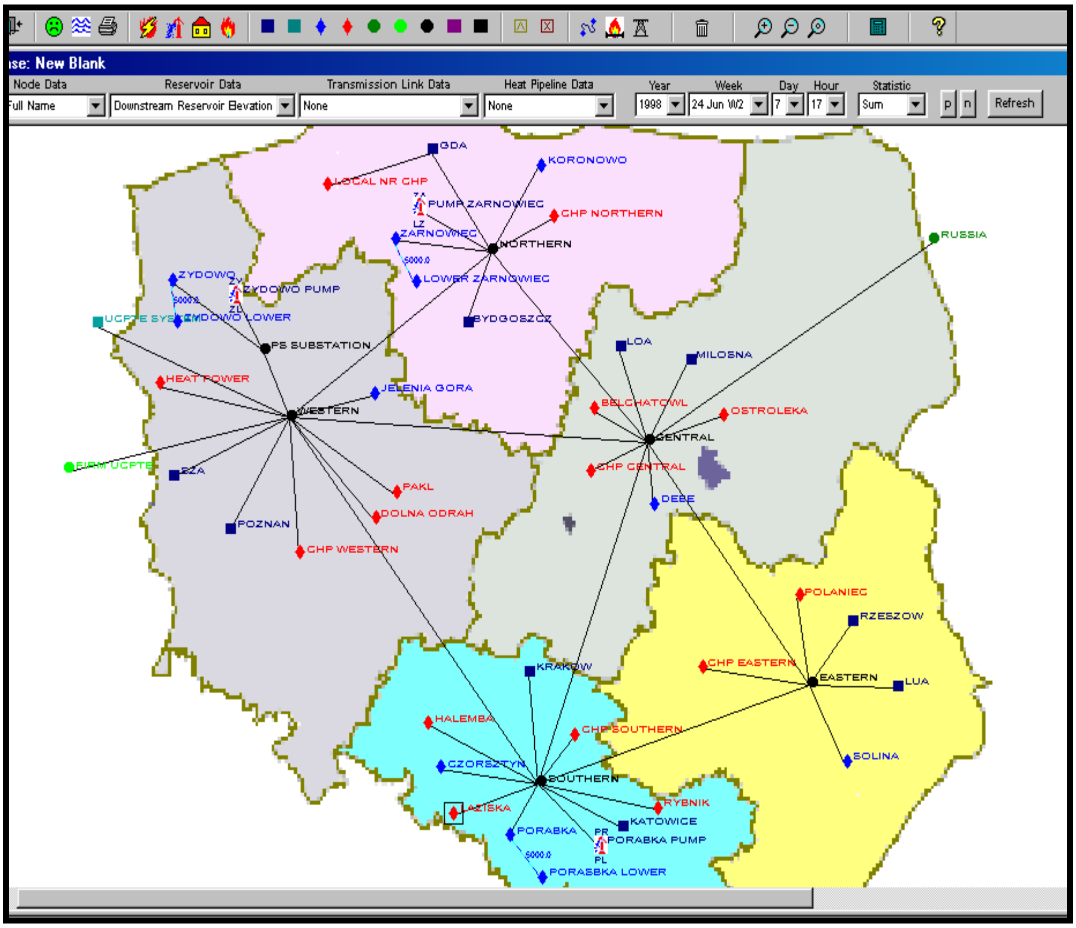


FIG. ES-13. Topology of the Polish grid network used in the GTMax model.

0.8.2. Results

0.8.2.1. Small-scale gas-fired CHP analysis

Revenues for a candidate CHP power plant were estimated for the peak load week. This plant is a small local CHP facility with a generation capability of 24 MW. The candidate plant was assumed to be located in the Northern region since this part of Poland is estimated by GTMax to have the highest marginal value of energy. Since the CHP was assumed to be located very near a load centre, losses would be negligible.

The CHP power plant generates electricity at full capacity for 14 hours per day from 9 am to 10 pm. This generation pattern is projected for all 7 days during the simulated week. The amount of money that owners of the CHP plant would receive is assumed to be the hourly market price of energy, as estimated by GTMax, multiplied by the amount of energy sold in the hour. However, a payment tariff structure was established for energy sales. Based on an earlier study conducted by EMA, the average payment that would be received by CHP owners is about 43.25 $/MW·h. This is somewhat lower than the average price that is estimated by the GTMax model.

Table ES-11 shows the estimated revenues and incremental production costs for owners of a CHP facility. Incremental production costs are estimated to be between 6 to 10 $/MW·h. This is the cost difference between operating the plant for only heat production and for generating both heat and electricity. The CHP operational expenses of $23 530 shown in the table is based on a 10 $/MW·h incremental production cost. Revenues or the amount owner would receive during the peak load week is about US $109 000. The difference or short-term net revenue is about US $86 000. When an incremental cost of 6 $/MW·h is assumed, the net revenue increases to more than $95 000. Over the lifetime of the project, these net short-term revenues must be large enough to pay for all fixed O&M expenses plus capital expenses. Although a company may have positive short-term net revenues, in the long-term the company may become bankrupt.

TABLE ES-11. GTMax estimates of net revenues from CHP electricity sales

Day	Revenues ($)	Incremental Cost ($)	Net Revenues ($)
Sun	12,374	3,360	9,014
Mon	16,323	3,360	12,963
Tue	16,555	3,360	13,195
Wed	16,908	3,369	13,539
Thu	16,946	3,360	13,586
Fri	15,858	3,361	12,497
Sat	14,375	3,360	11,015
Grand Total	109,340	23,530	85,810

0.8.2.2. Transactions East–West analysis

In order to represent East–West international power transfers, two additional nodes, shown in Fig. ES-13, were created: one injection node of firm purchase RU (Russia) and a sink node of firm sale GE (Germany). The objective was to determine:

- maximum power to be transferred in the framework of the “East–West Bridge” by the existing Polish Transmission Grid;
- wheeling cost of the power transmission.

To that goal a number of simulations were performed for the 24th week (June) and 48th week (December). A wheeling costs curve was determined by setting increasing transmission power. These costs include two factors: additional transmission costs caused by the transactions and higher costs due to distortions in the optimal power dispatch. The projected wheeling costs are presented in Fig. ES-14.

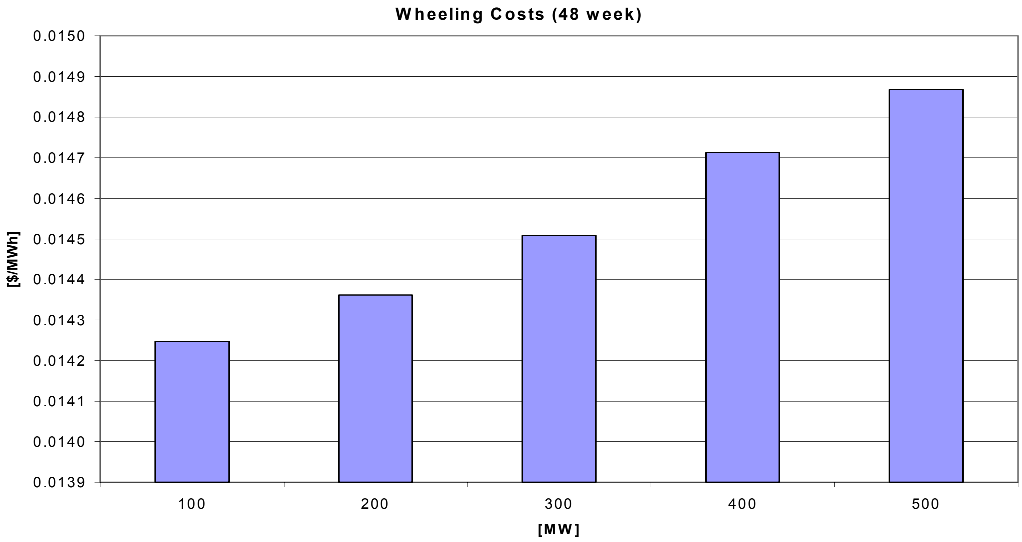


FIG. ES-14. Wheeling costs of the East–West transmission through existing grid.

In order to obtain a rough estimate of contractual power transfers across Poland available transmission capabilities (ATC) were calculated. The GTMax model bases these computations on the total transfer capability (TTC) that is input into the model minus contractual energy flows computed by GTMAx. Results for ATC over user-defined paths are provided in Fig. ES-15. Estimated values are relatively small for the Northern path while the central path has the highest values that at times exceed over 2000 MW. The northern path is often at or near its defined transmission transfer capability since the Northern region has a supply shortage that is satisfied via less expensive production for the western and eastern regions.

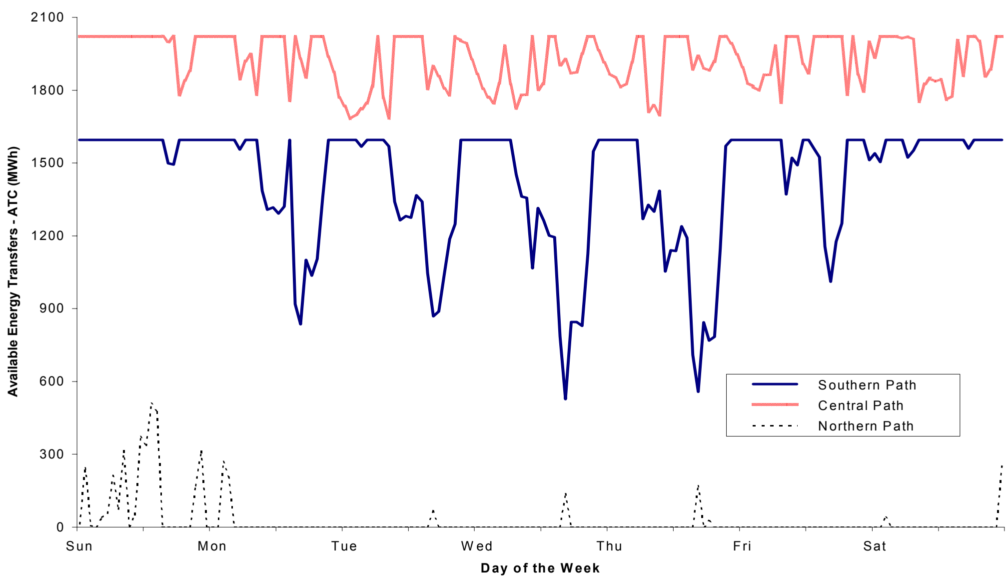


FIG. ES-15. Computed ATC values for three paths across the Polish power system.

0.9. Conclusions

Long-term energy requirements:

The long-term energy demand forecast was based on three different scenarios of the macroeconomic development of Poland by 2020. Depending on the scenario, the assumed average annual economic growth ranges between 2.3% and 5.5%.

As a result, a small (below 0.1 to 0.5%) annual increase of final energy demand (FED) is projected. In all scenarios, a 5–7% decrease of total final energy demand is projected till the year 2005, and only thereafter a gradual rise is observed. Nevertheless, the final energy demand per capita in Poland will remain significantly (~30%) below the corresponding values in the EU countries.

The demand for the electrical energy will grow in all sectors faster then the total energy demand (2–3% average annual growth rate), with the most significant increase expected in the residential and commercial sectors.

The projected primary energy requirement in 2020, ranging from 112.2 to 121.3 Mtoe, will stay below its 1988 level.

Coal share in primary energy supply is still the highest but decreases strongly, from about 56% in 1997 to below 45% in 2020. Hard coal remains the main energy carrier for power and heat co-generation, where its use moderately but steadily increases over the study period. Lignite production stays virtually unchanged but its share decreases.

Independent of scenario, the share of natural gas will continue to increase strongly. It more than doubles in 2020 compared to 1997. For electricity generation, gas constantly increases its share from virtually zero in 1997 to between 11 and 15% in 2020. This means large gas imports, lowering the security of supply. Consequently, the diversification of suppliers becomes a priority.

A modest increase of the share of liquid fuels is projected, which increases oil imports.

Due to the low cost-effectiveness, the currently low share of renewable energy sources will not change significantly, and will stay below 6.5%. Special promotional measures would have to be taken if the share of renewables in the overall energy mix is to be increased.

Whereas currently Poland has a quite high index of energy self-sufficiency (above 80%), a steady decline of this value is predicted over next two decades to about 60% in the year 2020, which is still above the present average value for the EU countries. However, increased gas imports will have a positive impact on fuel diversity, beneficial to the security of supply.

Long-term power system expansion:

New public generation plants would be required only after 2010. They are mainly combined cycle gas turbines (CCGT) and peaking gas turbine plants.

It is expected that the share of CHPs in electricity production would reach 35–40% in 2020, a more than two-fold increase in comparison to 1997 level.

No nuclear power capacity is projected. The reasons are: insufficient economic competitiveness of nuclear plants, availability of cheaper alternatives, and the absence of environmental motivation.

Environmental analysis:

A significant decline of particulate matter emissions, about 50% reduction by the year 2010, is observed in all scenarios.

The first two targets of the Second Sulphur Protocol (for the year 2000 and 2005) concerning the sulphur dioxide emission reductions can be easily met, however, the next emission level — 1400 kt after the year 2010 — although achievable, might be harder to comply with.

Despite the projected decrease of NOx emissions, meeting the target set by the UN-ECE 'Gothenburg Protocol' would require further substantial reductions.

The Kyoto Protocol (6% reduction of greenhouse gases emissions in the period 2008–2010, compared to 1998 level) seems relatively easy to achieve. By 2010, Polish CO_2 emissions will be 15–20% lower than in Poland's baseline year of 1988.

Short-term operation of the power system:

This analysis, implemented with the GTMax model, was limited due to the lack of time. Nevertheless, short-term electricity flows in the Polish grid were modelled successfully and allowed to determine the following:

- The incremental production costs for the CHP facility are estimated to be between 6 to 10 \$/MW·h. Per year, the short-term net revenue is about US \$90 000. Over the lifetime of the project, these net short-term revenues must be large enough to pay for all fixed O&M costs plus capital expenses.
- The available transmission capabilities (ATC) of the Polish grid for the “East–West Bridge” varies between zero (if the Northern path is used) and some 2000 MW (for the Central path). The northern path is often at its defined transmission transfer capability while the ATC of both the Southern and the Central path is relatively high – between 600 and 2000 MW.
- The wheeling costs curve was determined by setting increasing transmission power. The costs vary between 1.42 and 1.49 cent/MW·h.

1. STUDY ORGANIZATION, BACKGROUND, AND OBJECTIVES

1.1. Background

The Technical Co-operation (TC) Project for Poland *"Comparative Studies on Natural Gas and Nuclear Power"* was implemented in 1999–2000 by a national team with support of the International Atomic Energy Agency (IAEA). The principal objective of the project was to assess economic competitiveness and environmental impacts of different energy options, including natural gas and nuclear power. The project was carried out in parallel with the preparation of a Governmental document *"Energy Policy Guidelines till 2020"* [1] and its main attachment "*Long-term Energy Demand and Supply Forecast till 2020"* [2]. These documents were prepared using project results and published in February 2000.

The studies were carried out by a national team of experts including representatives of the most important agencies and organisations involved in the decision-making process for energy and electricity planning. The Energy Market Agency (EMA) was designated as the national counterpart for the project since EMA was also the main co-ordinator of the task "Energy Policy Guidelines till 2020". It provided the overall co-ordination among the participating organizations. The IAEA assistance consisted of the release of energy models to Poland and expert missions to the country in the course of the project.

The project took into account the broad energy policies formulated by governmental decision-makers, such as:

- energy security of the country,
- competitive energy prices for end-users,
- minimisation of environmental pollution,
- structural changes and reorganisation in the country's economy including ownership changes in the energy sector, and
- integration of the energy sector as well as the entire economy with countries of the European Union (EU).

1.2. Study scope and objectives

The overall scope of the project is illustrated in Fig. 1. By implementation, the study can be divided into two distinct parts:

1. An analysis of the overall energy sector with a long-term forecast of energy demand till 2020 (formulation of energy demand projections, application of WASP, BALANCE, IMPACTS);
2. Partial analyses of the electric energy sector (application of GTMax and FINPLAN).

The main goal of the study was to develop a sound projection of the possible penetration of gas-fired power and co-generation plants and nuclear power as a replacement of coal. The analysis was based on different criteria such as, associated costs, import dependence/security of supply, environmental consequences (e.g., 2nd Sulphur Protocol and Kyoto Protocol), financial viability, etc.

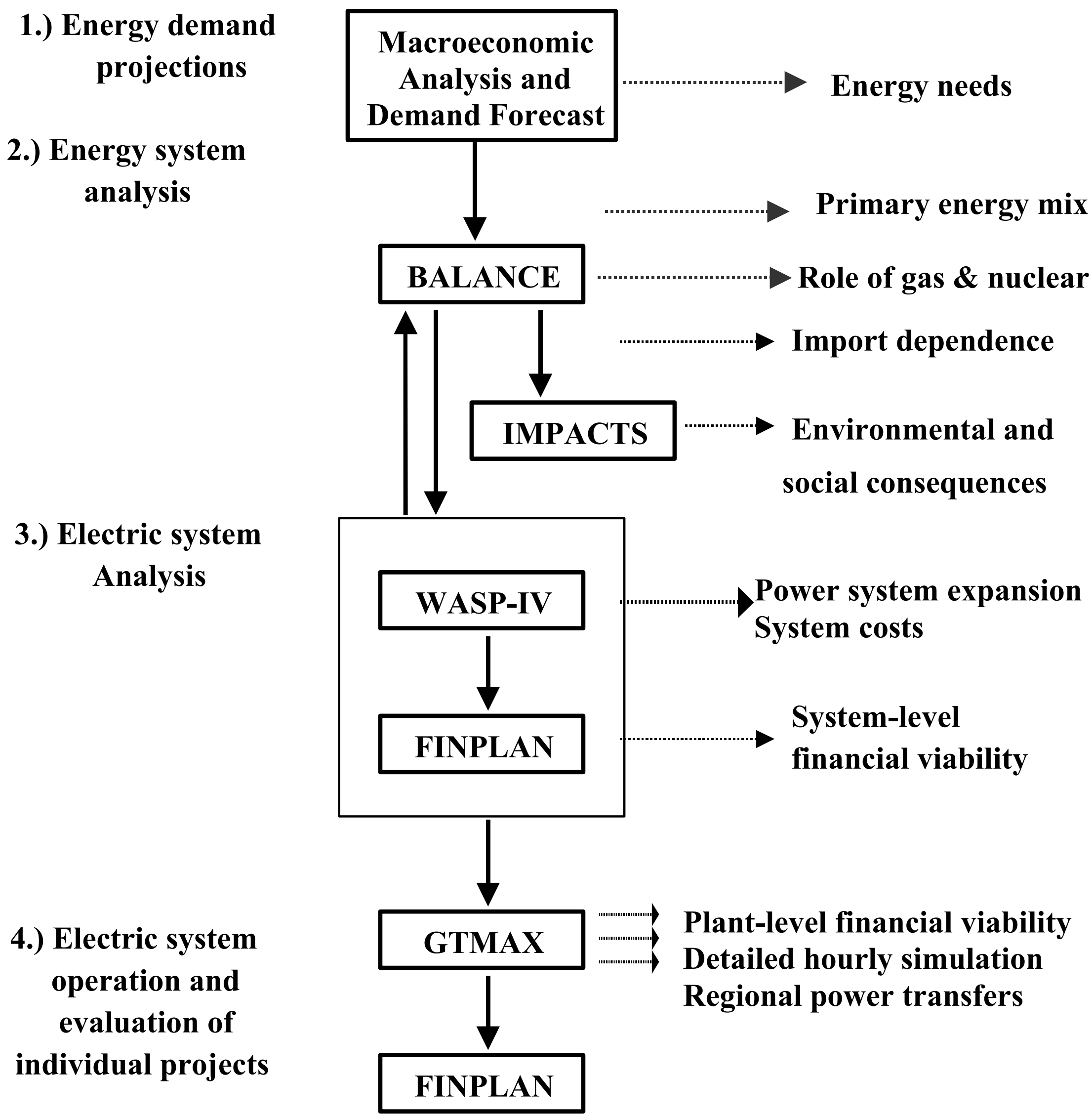


FIG. 1. Analytical scope of the study.

The first year of the project was planned for the realisation of the first part of the project, including:

- Using local models to perform a macroeconomic analysis, develop a long-term forecast of useful energy demand at the national level till 2020,
- Based on these projections perform a supply/demand analysis with the Agency's ENPEP model,
- From the ENPEP/WASP study assess the expanded role of natural gas and/or nuclear energy in the future energy mix of the country, and
- Using IMPACTS estimate the level of environmental burdens associated with alternative scenarios of energy sector development.

This work was essential for the preparation of the Governmental document "Energy Policy Guidelines till 2020" [1]. It was successfully completed and the main results were published in early 2000 as "Long-term Energy Demand and Supply Forecast till 2020" [2].

The second year of the project was planned for the implementation of Agency's new computer tools (WASP-IV, FINPLAN and GTMax). It was planned to use these tools to:

- Refine electric sector expansion plans with WASP-IV and investigate financial viability of the expansion programme using FINPLAN;
- Use the GTMax model to investigate the technical and economic advantages of gas-fired combined heat and power (CHP) plants and nuclear generation in an open Polish power market; and
- Use the results from GTMax as input to FINPLAN to assess the financial viability of CHP plants that are constructed and operated by independent power producers (IPP) or by a local distribution company.

Unfortunately this part of TC Project was completed only partially, and the main results presented in the report concern only the application of the GTMax model. Since prospects for nuclear energy in Poland showed to be beyond the assumed study period, and natural gas was accepted by decision-makers as a prospective fuel not only for the public power plants but also for small-scale local CHP generation, GTMax was used only for technical and economic assessment of the latter. Specifically, the subject of analysis was the use of small-scale gas-fired CHP plants that are projected to be the main alternative to existing coal-fired district heating facilities. Although limited in scope, results of these partial analyses were found quite useful for the short-term energy forecast that is presently under preparation for the Government.

Financial analysis with FINPLAN was limited. The model was used, but it was not possible to conduct a meaningful study. Interactions of WASP-IV or GTMAX with FINPLAN was not analyzed. Consequently, this analysis is not presented here.

There are several reasons why this part of the project was not implemented as initially planned:

- In contrast to the first stage of the study in which standard IAEA energy analysis tools that were familiar to the research team had been used, the second stage involved the use of new tools (FINPLAN, GTMax), introduced to EMA only in mid-2000. Consequently, analyses performed with their use should be treated rather as an effort to mastering them for the future use.
- It was expected that the Polish Grid Company would take active part in this part of the project as well as provide some financial support. Unfortunately, it did not happen due to the lack of interest at the time.
- Two key members of the research team (one of them the main WASP expert) left EMA unexpectedly in early 2000, rendering the completion of the project as initially planned unrealistic.

Thus, the first part of the project, which was most relevant to the preparation of the mentioned Governmental policy documents, was implemented in much more detail than the second part.

1.3. Organization of project implementation

A project Steering Committee was established in order to formulate guidelines for the energy options to be considered and to validate project documents. The Steering Committee included representatives of:

- Ministry of Economy,
- Polish Power Grid Company,
- Polish Oil and Gas Company,
- Economic Association of Polish Power Plants,
- Polish Association of Electricity Transportation and Distribution,
- Polish Association of Public CHP Plants,
- Association of Brown Coal Producers, and
- "Polish Oil" Company.

The Energy Market Agency (EMA) was the leading organisation for carrying out the technical study, with consultation from the IAEA and Argonne National Laboratory (ANL), USA. The working team at EMA was responsible for:

- collection of technical information required for the project,
- preparation of input data for the models used,
- model application and analyses of the results, and
- preparation of project documents.

The members of the Working Team (EMA) were:

- Jacek Nowakowski, the leader of the project,
- Marek Kumanowski, Vice-President of EMA,
- Zygmunt Parczewski, Head of Energometrics Division of EMA,
- Andrzej Kerner, Head of Energy Policy Planning Group, and
- Sergiusz Aleksandrow, Sławomir Ciok, Jan Dołowy, Zinaida Głanc, Uroš Radović, Grażyna Wacławiak, and Jacek Woroniecki — Staff of Energy Policy Planning Group.

The selection of the macro-economic scenarios that were used in the project was based on studies carried out by two independent research centres: the Institute of Development and Strategic Studies (IRiSS) and the Polish Foundation of Energy Efficiency (FEWE).

The organizational scheme of the project is illustrated in Fig. 2.

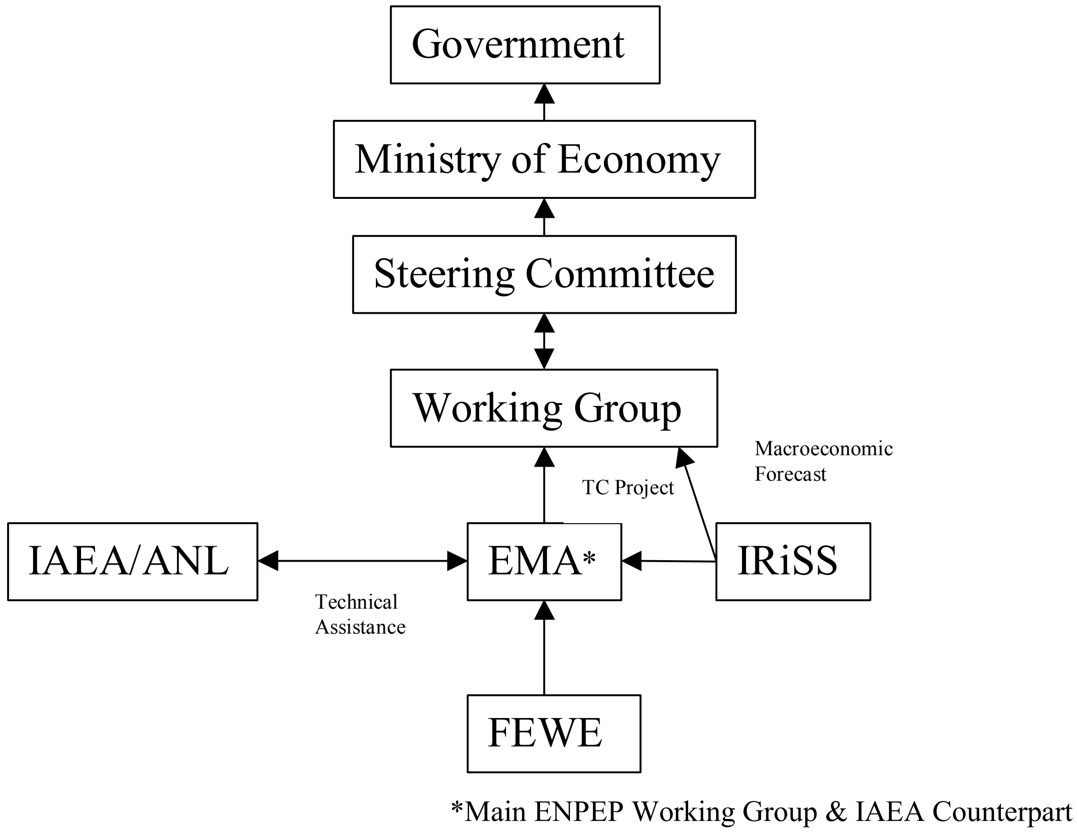


FIG. 2. Organizational scheme of the TC project.

2. COUNTRY BACKGROUND

2.1. Poland: Geography, climate, natural resources, and population

The Republic of Poland (Rzeczpospolita Polska, Fig. 3) is one of the largest countries in Central Europe. Poland's shape is roughly square, measuring 650–700 km across. With a total surface area of 313 thousand km^2, Poland ranks eighth in Europe. It lies in the European Lowland, between the Baltic Sea and the arc of the Carpathian Mountains, and is bordered by the Russian Federation, Lithuania, Belarus and Ukraine to the east, the Czech Republic and Slovak Republic to the south, and Germany to the west. Poland's northern frontier on the Baltic Sea gives it easy access to Scandinavian and North Sea ports.

FIG. 3. Republic of Poland – administrative division since 1999.

Poland is generally composed of lowlands. The average altitude is only 173 m above the sea level, while about 97 per cent of the area lies between 0 and 500 m and only 2.9% has an elevation between 500 and 1000 m. Agricultural lands cover 60% of the territory. Approximately one-fifth of the land is maintained as pasture and meadows. Forests and wooded areas make up about 27% of the territory.

Water resources, including hydroelectric potential, are rather small. Surface waters in Poland are dominated by lakes and rivers. Reservoirs occupy 8313 km^2; that is, 2.7% of the territory of the country. There are over 9000 lakes, majority of them of glacial origin, whose surface size exceeds 1 ha. The longest rivers that cross the country northward are the Vistula (1027 km) in the centre, and the Odra (816 km) that flows along Poland's western border.

Poland has a moderate Atlantic-continental climate. It represents a transition zone from the maritime climate type of the Atlantic Ocean to the continental one of the east European Plain. Generally, summers are warm and winters cold. The annual average temperature ranges between 6 and 9°C. Spatial climatic differences in Poland are significant and weather changes quite frequent. The average January temperature is –1°C in the north and –5°C in the southeast. The July average temperature varies from 16.5°C near the coast to 19°C in the south. Rainfall, with an annual average of 600 mm, varies with altitude, ranging from less than 450 mm a year in the lowlands to over 1200 mm in the southern mountains.

Poland has substantial mineral and agricultural resources. It has world's fifth largest proven reserves of hard and brown coal in addition to deposits of copper, sulphur, zinc, lead, and silver, as well as magnesium and rock salt. There are also commercially viable deposits of chalk, kaolin, clays, potash, and natural gas. The main agricultural crops are wheat and other grains, potatoes, sugar beets, and fodder crops. The livestock sector consists of 8 million beef and dairy cattle and 19 million pigs. Total arable land is 18.7 million hectares. In addition, 8.9 million hectares are forested, making timber an important resource.

The population of Poland is about 39 million, and is expected to reach 40 million by 2010. Approximately 62% of the population live in urban areas; this share is expected to increase in the future. Warsaw, the capital and Poland's largest metropolitan area, has a population of 1.7 million. Some 43 cities have more than 100 000 inhabitants. Demographic trends in Poland are similar to those in western Europe, in that the country is currently experiencing a decrease in the proportion of the working-age population from 59.3% in 1980 to 57.6% in 1992. People in pre-working age constitute 30% of population and the elderly about 12%. The age structure is expected to slowly move towards a higher share of older people.

2.2. Recent political and economic evolution

A program of economic transformation of Poland from a planned socialist economy to a market-oriented one was prepared during the autumn of 1989 and launched at the beginning of 1990. The program combined a strong stabilisation package with an immediate implementation of trade and price liberalisation. It also proposed a set of structural reforms, which were to be gradually implemented over time. The integration with the European Union (EU) was perceived to be an indispensable element of the transformation process.

Poland inherited a negative socio-economic structure from the centrally planned economy, that was characterised by:

- low labour productivity and high latent unemployment,
- high share (about 40%) of the population living in rural areas,
- mix of production output heavily biased towards basic materials, and
- coal based both primary energy production and final energy consumption.

Moreover, in the year 1989 the economy was in chaos with hyperinflation. In January 1990 the Government started the economic policy of “shock therapy”, which assumed significant curbing of subsidies. The Government’s first steps included:

- liberalisation of most prices and the abolishment of main trade restrictions;

— monetary reform making the national currency (the zloty) convertible;
— nominal wage control by a tax on wage increase above a statistically determined norm; and
— tightening of monetary and fiscal policies.

These measures resulted in severe contraction of economic activities. The Gross Domestic Product (GDP) declined by 11.6% from 1989 to 1990, dragged down by a 25% decrease in industrial production as well 10.1% in investments (Figs 4, 5). From 1990 to 1991 GDP declined by an additional 7.6% and industrial production decreased by 17% [3].

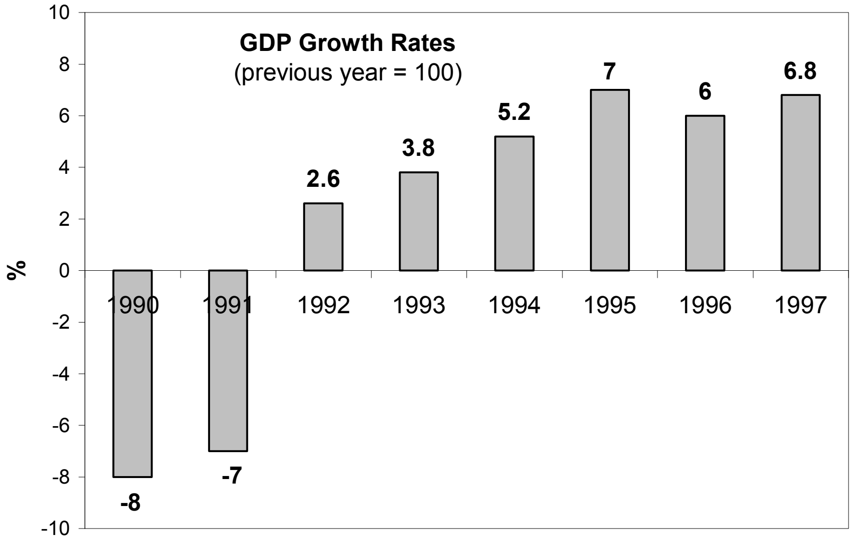


FIG. 4. Gross domestic product growth rates 1990–1997.

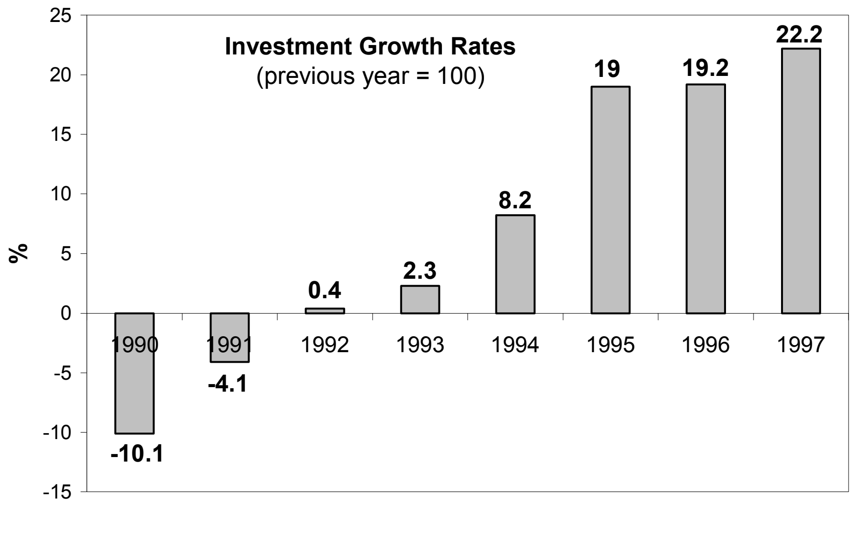


FIG. 5. Investment growth rates 1990–1997.

Social costs of economic restructuring were very high. Prices jumped by an average of 80% during the first two weeks of January 1990. The economic transformation had a negative effect on the financial situation of many households. Real wage rates dropped considerably, especially in the public sector due to budget cuts and price rises. Unemployment increased very fast: some 600 000 people lost their jobs in 1989 and more than 1 million in both 1990 and 1991 (Fig. 6). The highest unemployment rate was 16.4% (over 2.8 million people) in 1993.

Nevertheless, the Polish economy started recovering rapidly in 1992 due to an inflow of new investments and inflation control. Consequently, the rate of unemployment levelled off in 1994 and, thereafter, began to decline. Chronic unemployment still remains as the main threat to the economy in the long term. The situation is worsened by hidden employment that amounts to about 4% of the total employed labour force. Unemployment is particularly high in the agricultural sector (27% of total population generating just 10% of GDP), as well as in the hard coal industry.

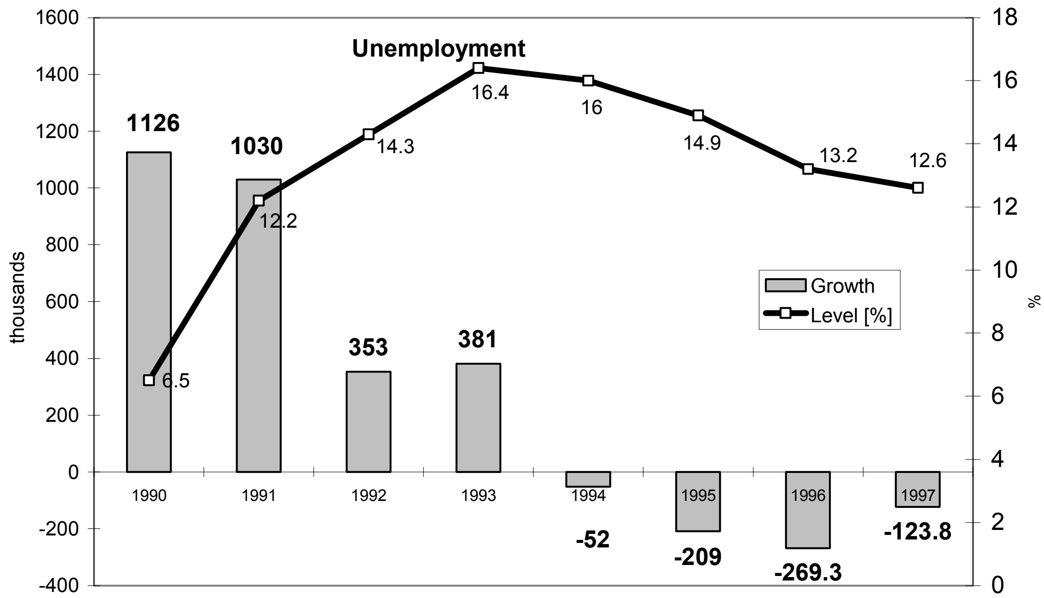


FIG. 6. Unemployment 1990–1997.

2.3. Key economic and energy indicators

Polish economy experienced two serious economic crises during the last two decades (Fig. 7). The first one, in the early 1980s, was a consequence of the political crisis while the one in 1989 was ignited by the transition to a market economy. Only in 1996 the GDP per capita exceeded the previous highest level of 1978.

There is a considerable difference in the structure of GDP between Poland and EU countries. The share of heavy industry and manufacturing is much higher in Poland than in industrialised countries such as France, Sweden, or the United Kingdom. The energy sector is also larger in comparison with the EU countries. On the other hand, Polish tertiary sector (trade and services) is quite underdeveloped when compared to world's leading economies.

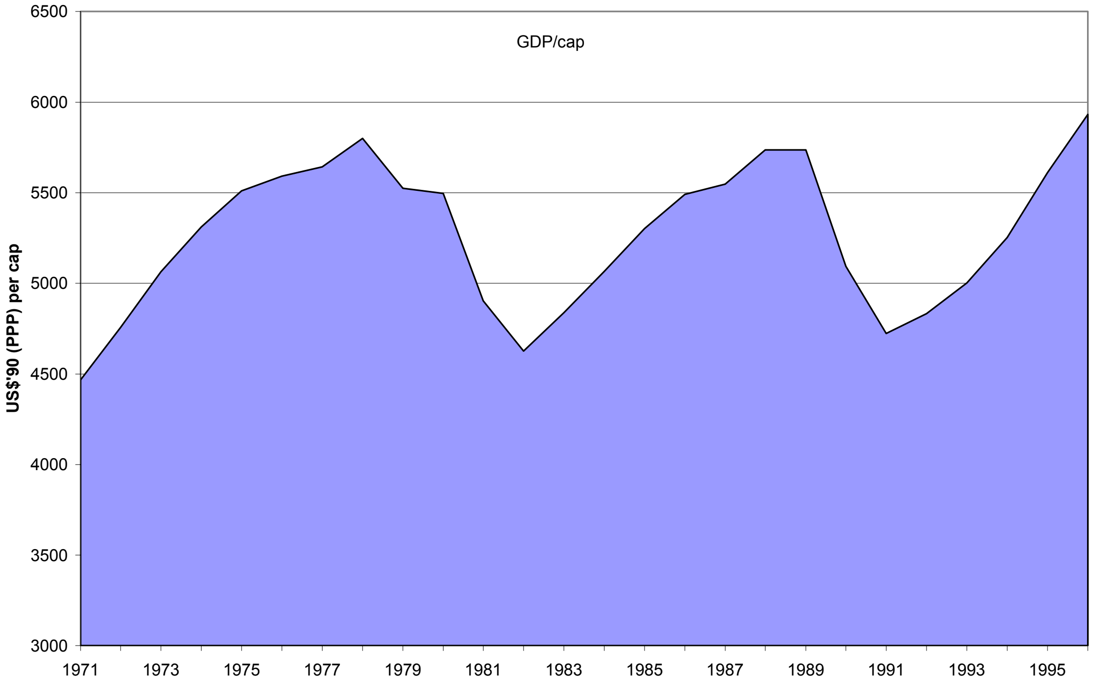


FIG. 7. GDP per capita.

Figures 8 and 9 compare two energy indices, total primary energy supply (TPES) per capita and electricity consumption per capita, respectively, for Poland and the EU [4]. Note that up to 1988, TPES indices for Poland and the EU did not differ significantly. However, while this index in Poland began falling rapidly in 1989 (when the transition to a market economy took place), in the EU countries a slight increase was observed through 1996. The per capita electricity consumption in Poland approximately follows the dynamics of the GDP index. It steadily increased up to 1979, followed by a drop during the first crisis. There was a second period of increase till 1988 followed by a decline during economic transformation. In 1994, the electricity consumption index began to rise, and a more significant increase is expected after 2000.

Energy and electricity intensities of GDP (the ratio of primary energy and electricity use to GDP) for Poland are significantly (about two times) higher than in the EU countries (Figs 10, 11). This is mostly due to inefficient equipment in Polish factories, and to the inefficiencies in Poland's district heating system — the most extensive network in the world. A systematic decrease in the energy intensity of GDP in Poland continues from the early 1980s, while a considerable decline of electricity intensity is noted since 1989.

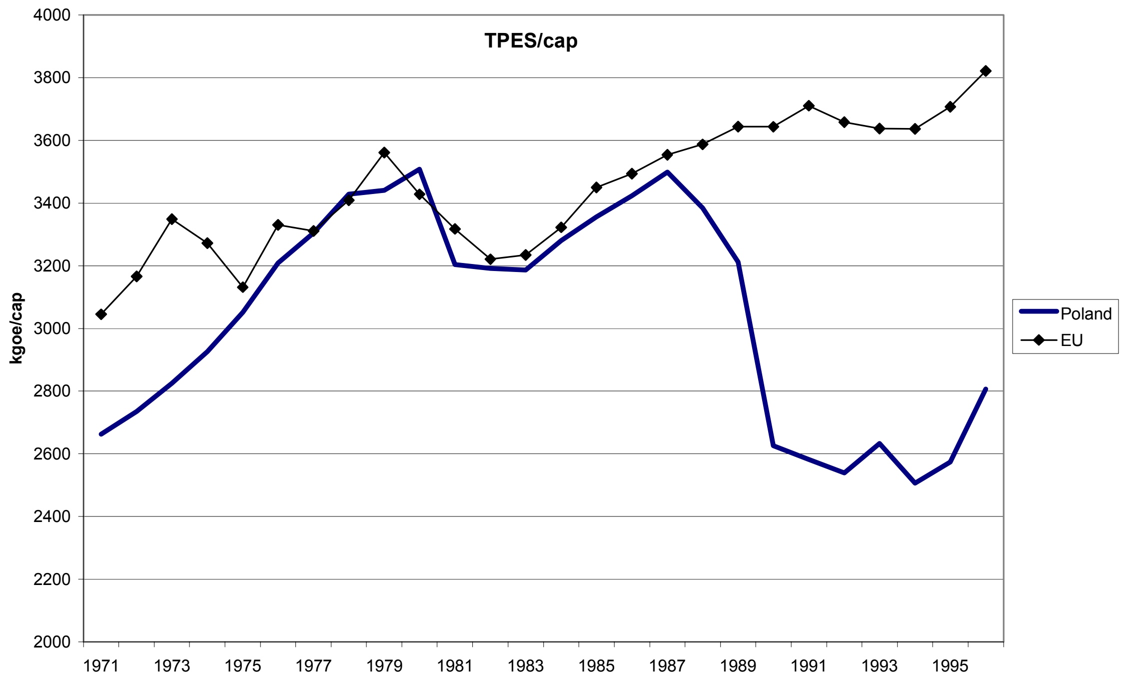


FIG. 8. TPES per capita index.

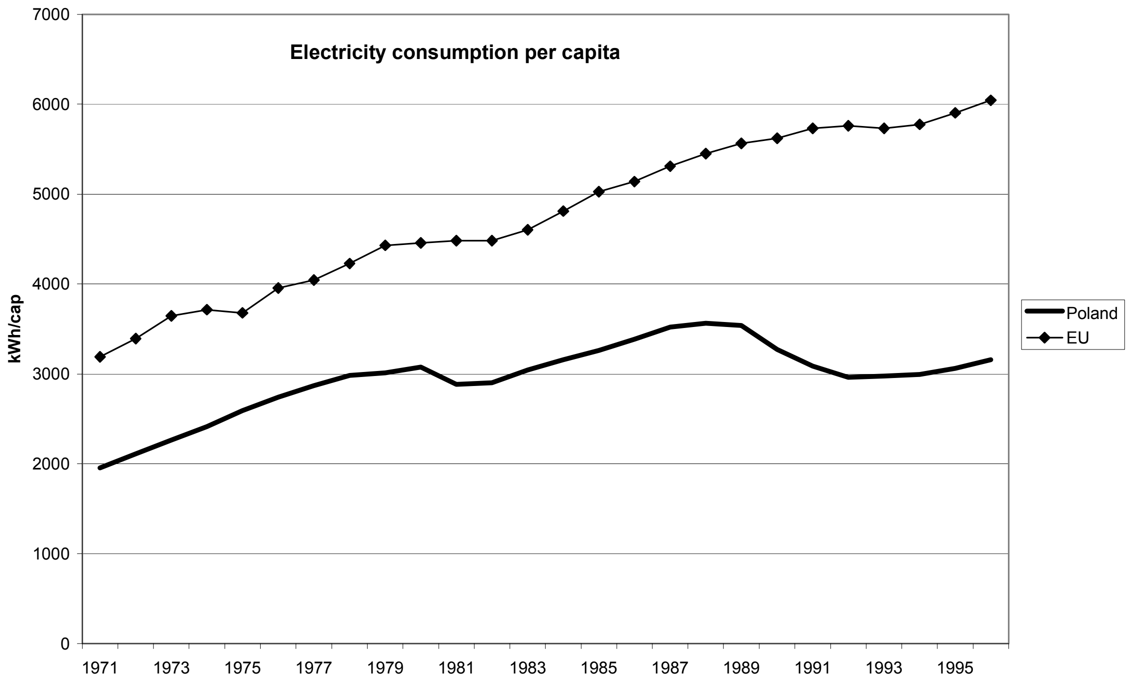


FIG. 9. Electricity per capita index.

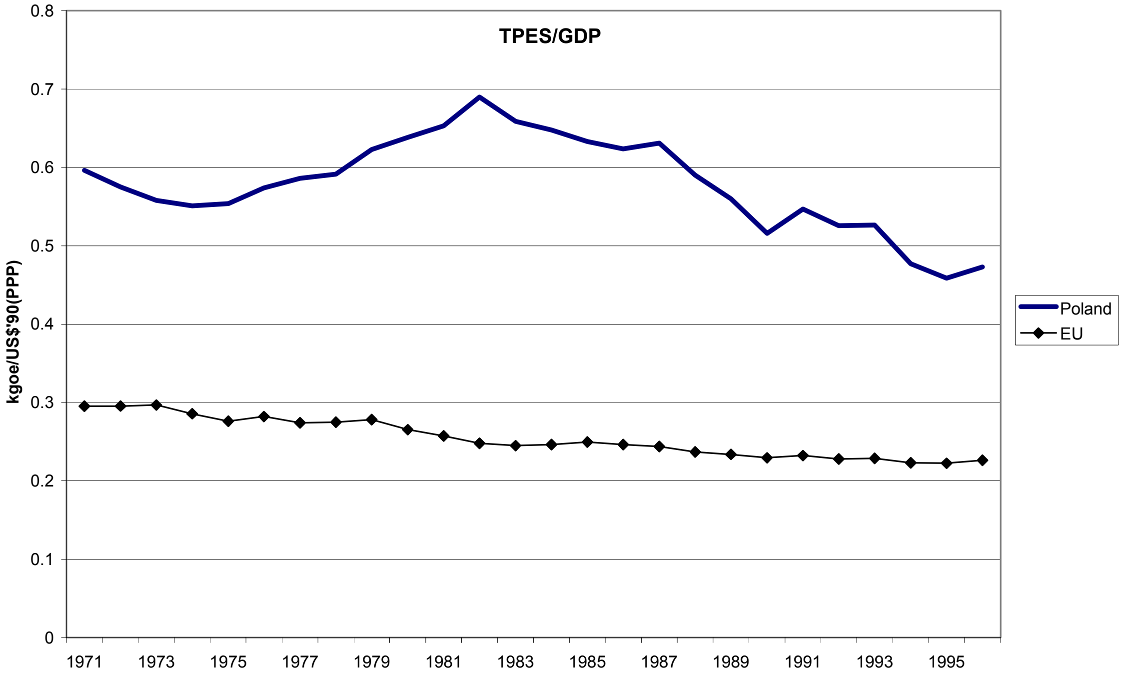


FIG. 10. TPES per GDP intensity.

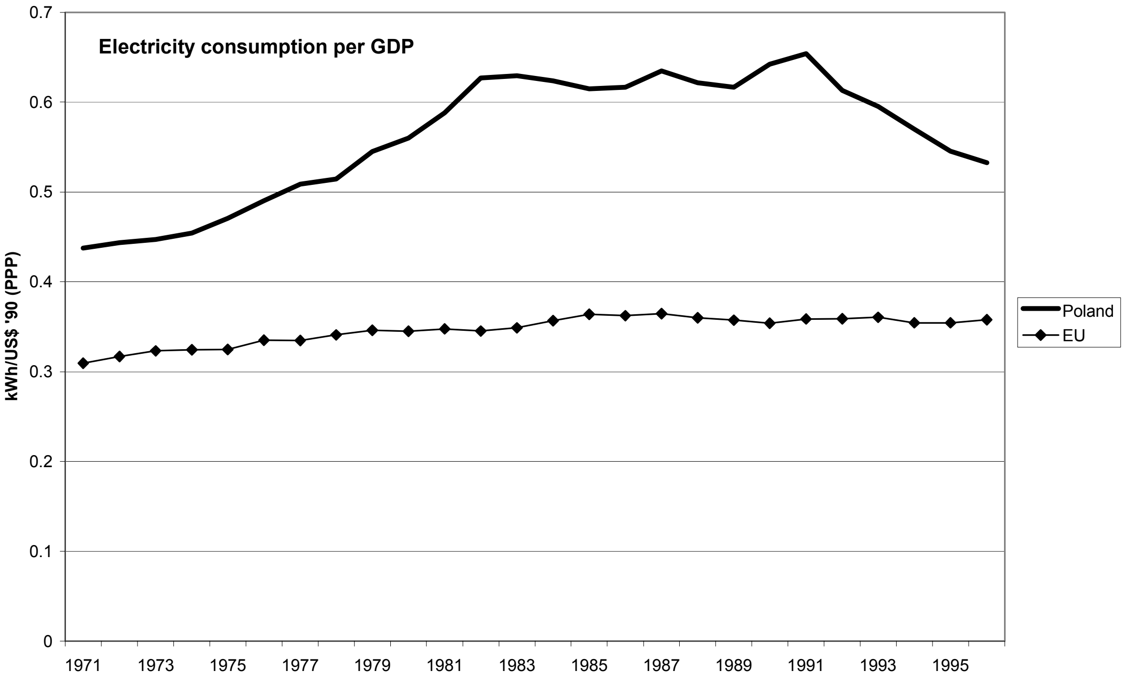


FIG. 11. Electricity per GDP intensity.y

2.4. Energy supply and use

Poland has considerable energy resources, but only in solid fuels; that is about 100 billion tons in hard coal fields and 16 billion tons in lignite fields.

In 1970, the energy supply mix in Poland was similar to many OECD European countries. However, since then OECD countries, to a great extent, substituted coal production with other energy resources. In contrast, Poland's energy production structure has not changed significantly. The share of hard coal and lignite is still above 90% (Fig. 12) [4].

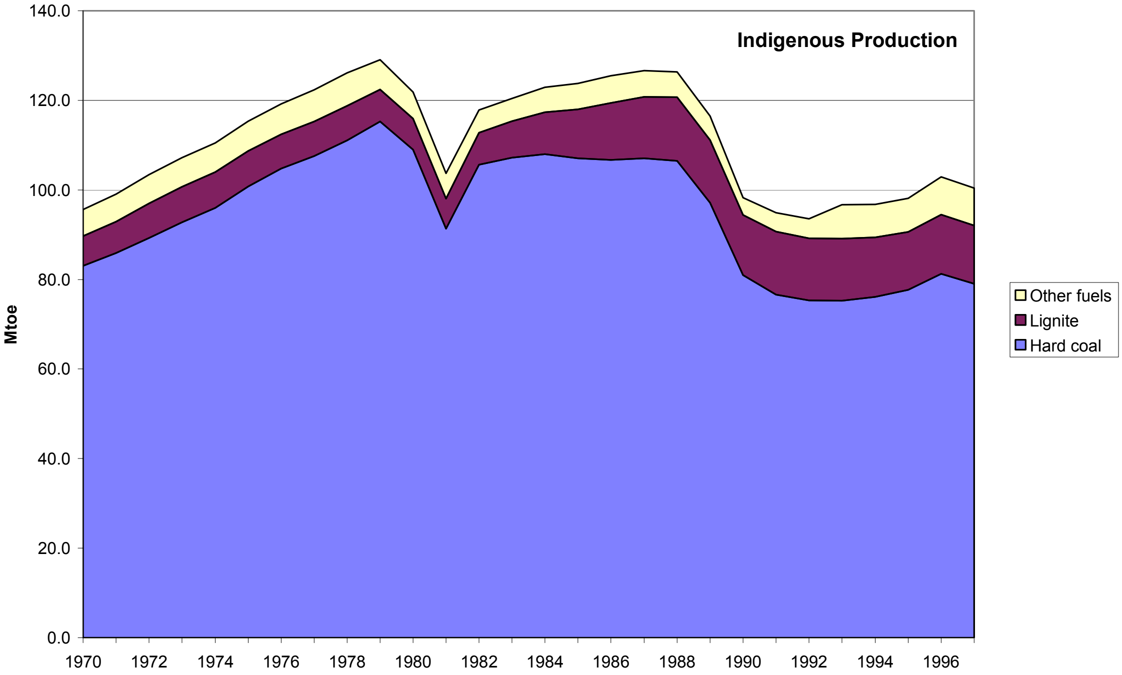


FIG. 12. Indigenous fuel production 1970–1997.

Poland's primary energy supply, driven by production, has always been dominated by coal (Figs 13, 14). All major power plants burn hard coal or lignite, and district heating systems are based mainly on hard coal. Industry, services and households use coal directly. The oil share has increased from 11–12% in the early 1970s to 15% in 1997. The fairly rapid increase in the 1990s — albeit from a small base level — reflects high consumption of gasoline and diesel fuel in the transportation sector. The natural gas share has increased from 6% in 1971 to 9.2% in 1997 due to the growth in the distribution pipeline network and household use. Hydroelectricity production (excluding pump-storage plants) contributes only 0.3% of TPES. The biomass share (commercial wood as well as traditional biomass used in households for heating and cooking purposes) was estimated at about 3.5% in 1995.

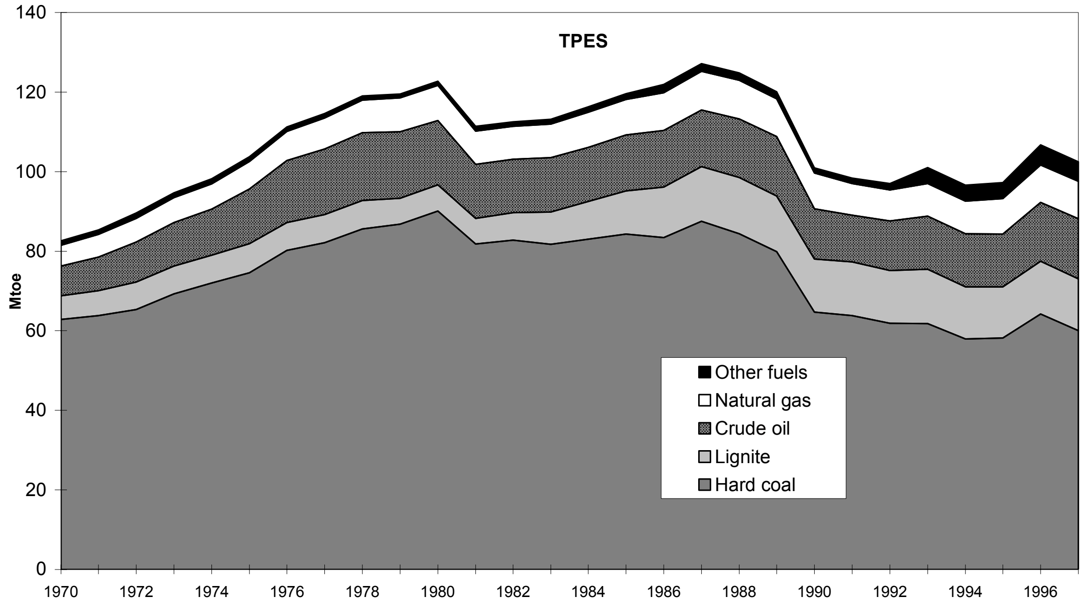


FIG. 13. Total primary energy supply.

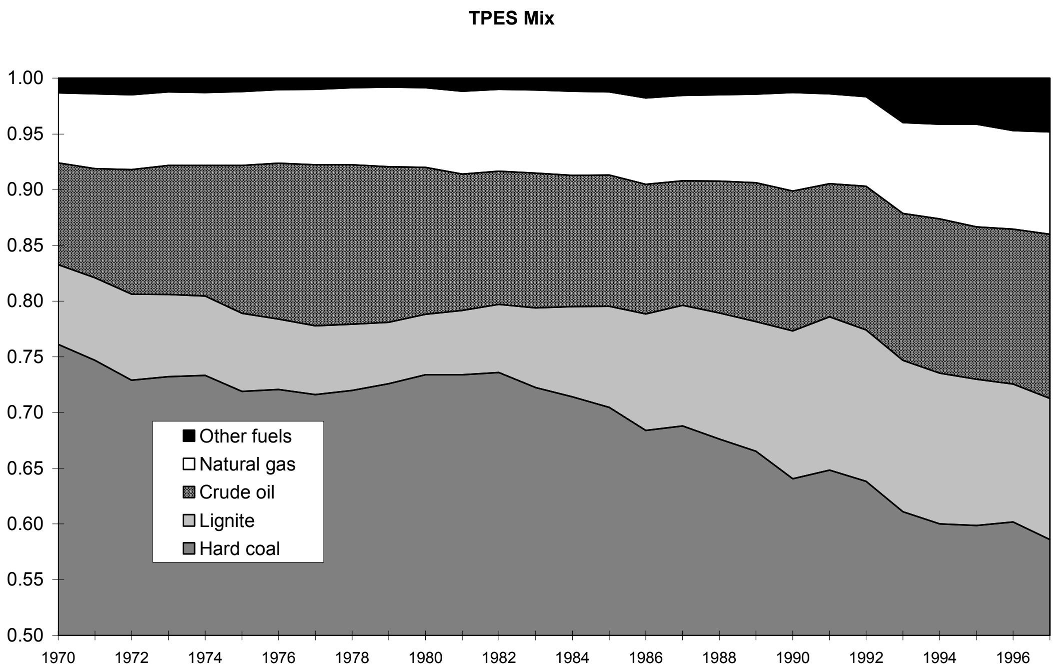
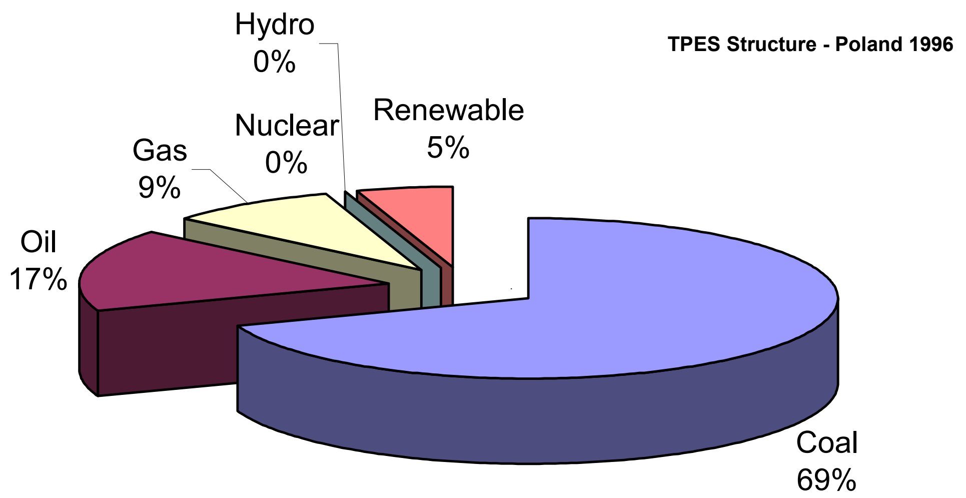


FIG. 14. TPES structure.

Poland's share of coal in TPES is still considerably higher than in EU countries (Fig. 15). In contrast, the corresponding shares of oil and natural gas are significantly lower [4].



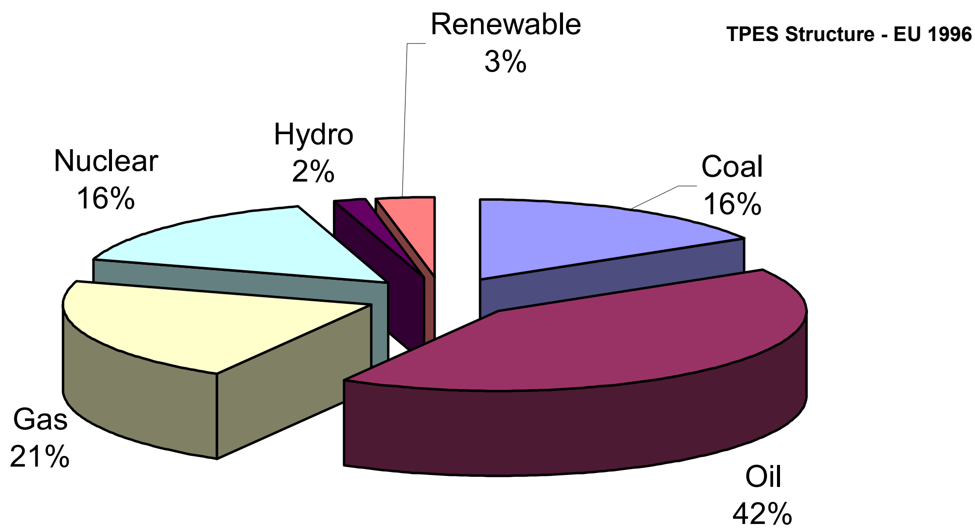


FIG. 15. Comparison of TPES structures (1996) of Poland and the European Union.

The total final consumption (TFC) of energy in Poland had been increasing steadily through 1980 [3]. It stagnated from 1980 to the late 1980s and started declining sharply after 1988. After 1991, TFC gradually increased to present levels (Fig. 16). The fuel structure of Poland's TFC changed more distinctly than the TPES structure. The share of solid fuels (hard coal, lignite, coke, and wood) in TFC fell from 52% in 1971 to about 40% in the 1990s. Meanwhile, the share of electricity increased from 7% in 1971 to 11.3% in 1997, and natural gas increased from 7% to almost 12%. Nevertheless, these shares still remain considerably lower than in EU countries (Fig. 18).

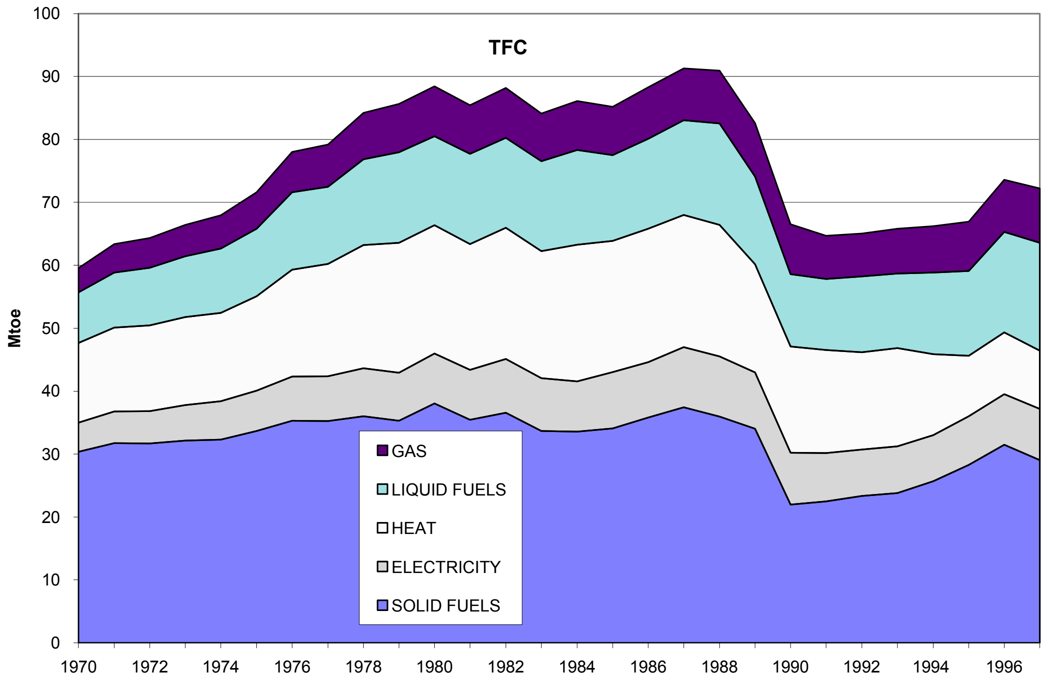


FIG. 16. Total final energy consumption.

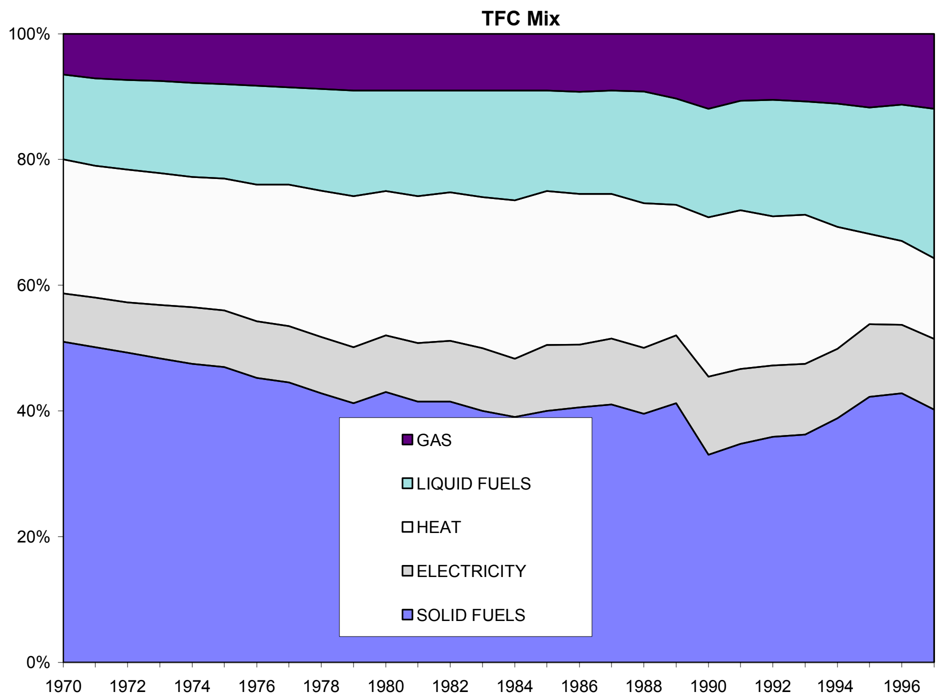
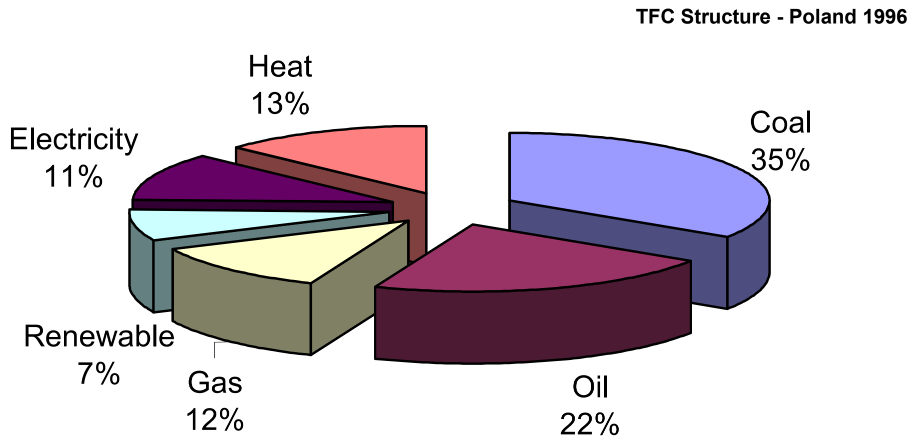


FIG. 17. Total final energy structure.



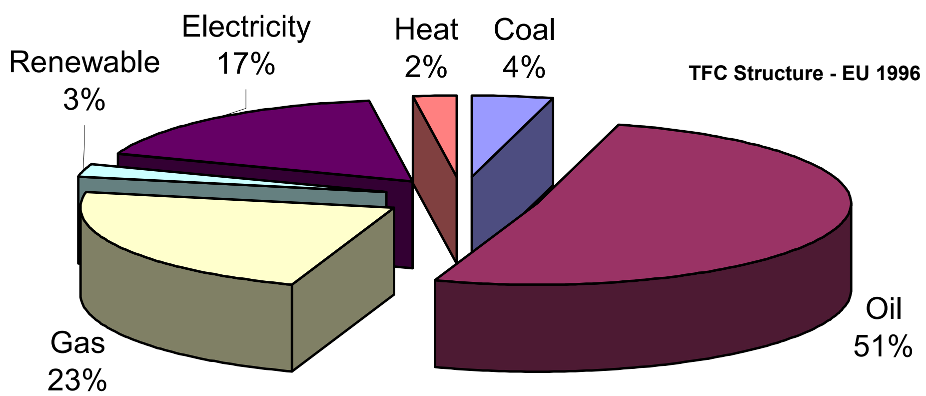


FIG. 18. Comparison of TFC structures (1996) of Poland and the European Union.

2.5. Hard coal industry

Coal is the dominant fuel in Poland, accounting for about 95% of total energy production and over 70% of total energy consumption. Power production is based almost exclusively on coal. The hard coal share of primary energy consumption in 1988 was 67% and fell to 55% in 1998. The coal share of electricity generation exceeded 57% in 1998. The share of hard coal in final energy consumption decreased from 50% in 1990 to approximately 40% in 1995, due to partial substitution of coal for wood. Hard coal has always been a significant source of convertible currency for the national economy. Its export varied: 31 million tons in 1980, 20 million tons in 1990, 27 million tons in 1997.

For many years the coal industry and coal prices to the consumers were heavily subsidised. The traditional principle was that subsidies assured the viability of coal mining. Although in 1993 coal subsidies were reduced, the coal industry is still partly subsidised and makes large financial losses. Figure 19 shows coal industry liabilities, receivables, and balance (receivables minus liabilities) [5]. The difference between the current and economic prices is covered by the non-payment of due liabilities.

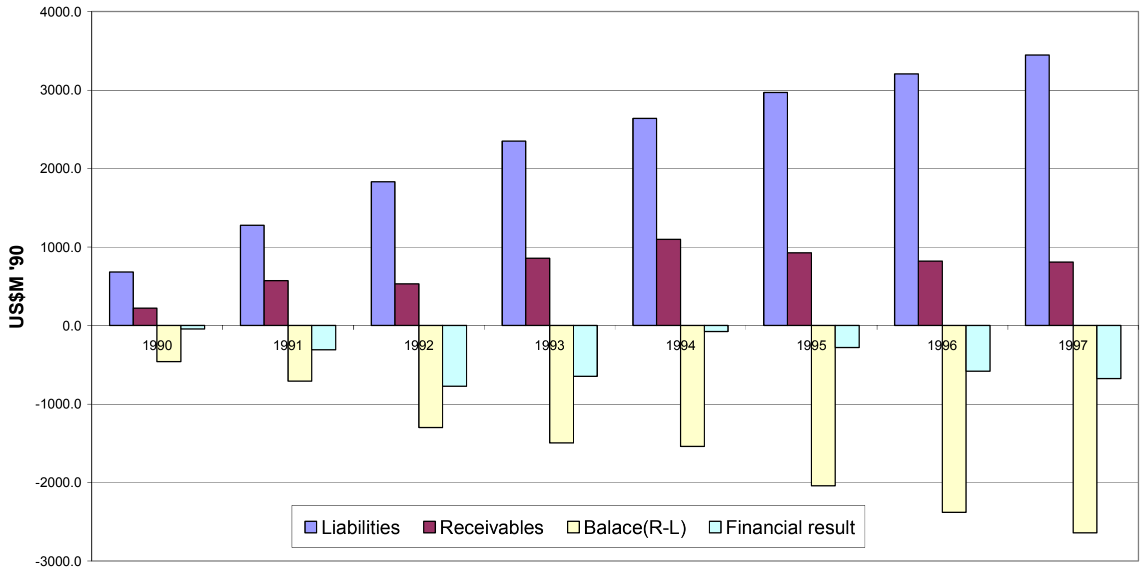


FIG. 19. Hard coal industry economic characteristics.

Such catastrophic condition was mainly caused by:

- inability of the hard coal sector to adapt to the current economic conditions induced by the free market policy of the government,
- significant coal surplus caused by dramatic reduction in domestic demand following the decline in economic activity and higher coal prices,
- maintenance of non-production fixed assets (housing for workers, recreational facilities, etc.),
- overemployment, despite a significant reduction of labour force from 415,740 in 1989 to 250,500 employees in 1997, and
- high cost of production due to low mechanisation in mining and washing processes, leading to high shares of wages in the total costs.

The average economic production cost for a tonne of reference coal is presently above 40 USD (Fig. 20) that is higher than the average coal price on domestic market and much higher than the export coal price.

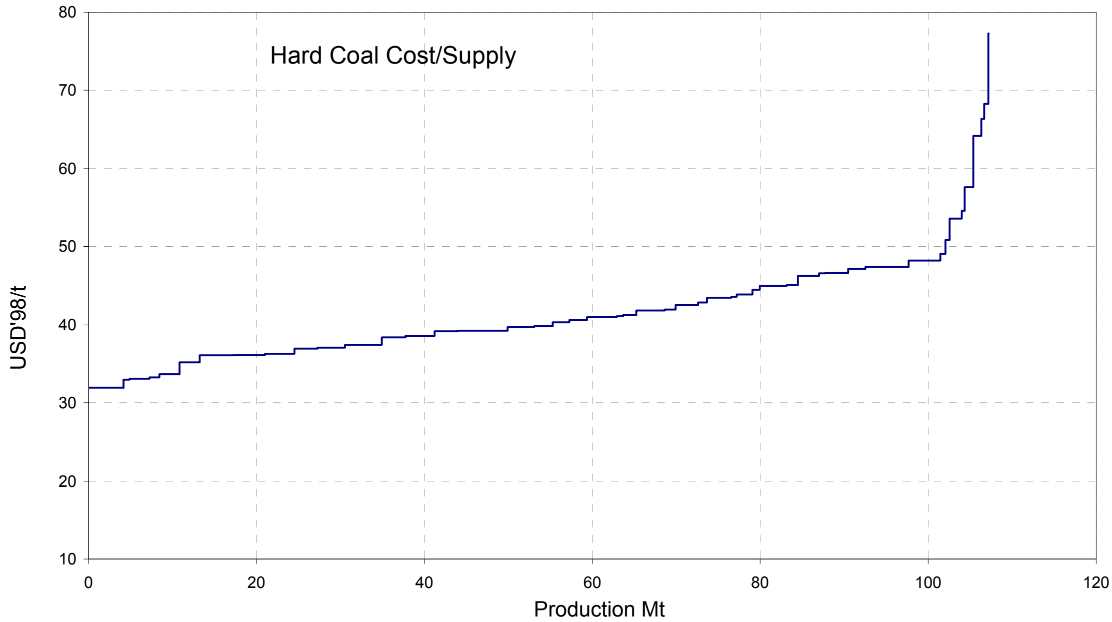


FIG. 20. Hard coal extraction cost/supply curve

The coal sector restructuring programme [5], introduced in 1996 and amended by the Parliament in 1998, lays down the strategy for the sector for the period 1998-2005. Its aim is to make the industry profitable by 2002. The main measures of the program include:

- cutting the high cost of production by closing the sixteen most ineffective mines,
- restructuring the remaining 57 mines and reducing their coal extraction to 25 million tons per year,
- reducing employment in the sector by a total of 105 000 people (attractive early retirement schemes and other policy measures have resulted in a larger reduction than foreseen for 1998), and
- clearing the debts of the industry.

Presently, most of the 70 coal mines have been grouped into 6 joint-stock companies. Coal prices are negotiated between the mines and the power plants.

2.6. Polish electric power system

A historical summary of installed electricity-generating capacity in Poland along with electricity generation and consumption in Poland is shown in Table 1. In 1997, installed electricity generating capacity in Poland was approximately 29 000 MWe. That year, Poland consumed almost 140 GW·h of electricity while generating 143 GW·h.

Over 97% of the electricity generated comes from thermal generation (hard coal, lignite, natural gas, oil), the remaining part is hydroelectric generation. No nuclear or significant amount of other technologies (e.g., renewables and waste) is used for electricity generation. Fuel types, as a percentage of power generated, are presented in the 1992 data shown in Table 2.

TABLE 1. Installed generation capacity (GWe), electricity generation, and consumption (in billion kW·h) in Poland, 1988–1997

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Hydroelectric	1.98	1.98	1.98	1.85	1.92	2.04	2.04	2.05	2.05	2.05
Conventional Thermal	28.13	28.95	28.77	28.85	29.07	26.62	27.08	27.59	27.42	27.66
Wind/Biomass	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*	<0,01
Total Capacity	**30.11**	**30.92**	**30.75**	**30.70**	**30.98**	**28.66**	**29.13**	**29.64**	**29.46**	**29.70**
Net Generation	136.2	137.1	128.5	127.2	125.4	126.4	127.8	131.2	135.2	134.8
hydroelectric	*4.2*	*3.7*	*3.3*	*3.4*	*3.5*	*3.5*	*3.7*	*3.8*	*3.9*	*3.8*
wind/biomass	*0.3*	*0.2*	*0.2*	*0.4*	*0.4*	*0.3*	*0.3*	*0.3*	*0.4*	*0.4*
thermal	*131.8*	*133.2*	*125.0*	*123.4*	*121.4*	*122.5*	*123.7*	*127.0*	*130.9*	*130.6*
Net Consumption	131.1	129.3	118.5	115.7	112.3	115.1	116.2	119.3	122.6	123.2
Imports	12.5	12.1	10.4	6.7	4.8	5.6	4.6	4.4	4.8	5.4
Exports	8.0	10.3	11.5	9.3	9.1	8.0	7.2	7.2	7.9	7.5

TABLE 2. Fuel sources for power generation in Poland, 1996

Fuel Source	Percent of Total
Coal	96.85
Hydroelectric	1.37
Fuel Oil	1.25
Natural Gas	0.25
Nuclear	0
Other	0.28
TOTAL	100

The Polish electricity industry has been reorganised into three layers of companies dedicated to the generation, transmission, and distribution sub-sectors. The generation sub-sector consists of large power stations (system power stations) and combined heat and power facilities (local facilities). Among the large power stations, 12 are state-owned and four are joint-stock companies. All 19 combined heat and power stations are joint-stock companies. The power generation sub-sector represents approximately 50 percent of all Polish electricity sector assets. The Polish Power Grid Company (PPGC or Polskie Sieci Elektroenergetyczne, PSE SA) is the owner of the transmission sub-sector and represents approximately 10 percent of the Polish electricity sector assets. The transmission sub-sector consists of 400 kilovolt (kV) lines (approximately 2,400 miles) and 220 kV lines (approximately 4,800 miles) connected by over 80 large substations. The distribution sub-sector consists of 33 distribution companies, all of which are joint-stock companies. The well-developed distribution network is along 110 kV, 15 kV, and 0.4 kV lines. Distribution companies represent approximately 40 percent of all Polish electricity sector assets.

Generation capacity construction in Poland has been inconsistent over the past 30 years, resulting in an ageing system that is becoming an increasingly serious problem. More than a half of the current capacity was built in the 1970s. Approximately 60 percent of the system is more than 15 years old, and 40 percent is more than 20 years old. This problem is exacerbated by insufficient expenditure on maintenance and modernisation. Polish power plant technologies lag behind recent developments in combustion and control technologies, as well as in environmental controls. The PPGC has estimated that by 2005 over 20 GWe of capacity would need rehabilitation while almost 3 GW_e would have to be retired. Rehabilitation costs, including environmental protection costs, are estimated between $50 and $350 per kW of capacity. If plans to extend transmission and distribution systems are factored in, the Polish electricity supply sector's total investment needs from 1995 to 2000 are estimated to be approximately $8 billion.

Generating capacity is expected to be adequate for the next several years, due to low economic growth and transition to a less energy-intensive economy. Near-term priorities are:

- completion of construction in progress on a new 2,160 MW_e coal-fired facility and pumped storage capacity of 750 MW_e;
- rehabilitation and retrofitting of ageing coal-fired generating equipment which is on average 18 years in age;
- improvement of availability, efficiency, and environmental controls, and reduction of losses of up to 10 percent in transmission and distribution.

The retrofit of flue gas desulphurisation systems and low-NO_x burners has started on coal-fired plants. It is expected that 4000 MWe are to be retrofitted by 2000 and 8600 MWe thereafter. In addition, coal-washing plants are being installed at 18 mines to reduce the sulphur content of hard coal burned at power plants.

The Polish electric power sector is in need of modernisation and refurbishment in order to create an economically efficient industry capable of meeting demand requirements. The cost of modernisation over the next fifteen years is estimated at $50 billion. Modernisation is needed to replace 16 GWe of obsolete installed capacity and to satisfy stricter environmental standards that came into effect in 1998. Of this amount, $15 billion is needed for the modernisation of existing power plants. A substantial portion of the modernisation cost will be covered by the income generated from privatising power enterprises.

Poland's electric power sector is in the process of restructuring (with World Bank support) into three subsystems: generation, transmission, and distribution. Plans call for reducing the number of generating companies from 35 to 7 and privatising power generation by the end of 2001. A new energy law that took effect in December 1997 sets the groundwork for third-party access to the power grid and vests authority in an independent Energy Regulatory Office.

So far, only one Polish generating plant has been privatised, while the second privatisation is underway. Electricite de France (EdF) purchased a 55 percent stake in a co-generation plant in Kraków, while two competing bidders (Elektrim consortium and National Power) have qualified for the purchase of a minority stake in the lignite-fuelled Patnow-Adamnow-Konin power complex, which controls over 10 percent of Poland's generating capacity.

Foreign investors are involved in joint venture projects to build new power plants, mainly using natural gas to generate both heat and electricity. These include Enron's Nowa Sarzyna plant, expected to be completed by the end of 1999, and another in Zielona Góra being developed by Eurogas and National Power International. Plans for new coal-fired plant to replace an ageing existing plant in Belchatów are under investigation.

2.7. Environmental situation

In the past years, Poland ranked among the most polluted countries in Europe. Extensive mining and extraction activities, emphasis on heavy and chemical industries, lack of pollution control equipment, economic development based on devastation of natural resources and dependence on fossil fuels, have contributed to the existing situation.

Among environmental issues, the following ones are significant:

- High emissions of air polluting agents from the energy supply sector and heavy industry as well from individual coal-fired heating installations and urban traffic,
- Water pollution of the Vistula and Odra rivers by waste saline water from coal-mines, and
- Solid waste disposal from coal mines and power plants.

Although the contribution of Poland to the total European air emissions, in absolute terms, is not as severe as often considered (comparable, for instance, to those of the United Kingdom or Germany), the situation is much worse when the level of economic activity is taken into account. Air emissions in Poland, expressed per GDP unit, are much higher, especially when compared to such countries as France, Finland, or Sweden (Fig. 21). Emissions of SO_2 in relation to GDP are of particular concern as they are approximately 4 times higher than in the UK and much higher than the average of OECD Europe.

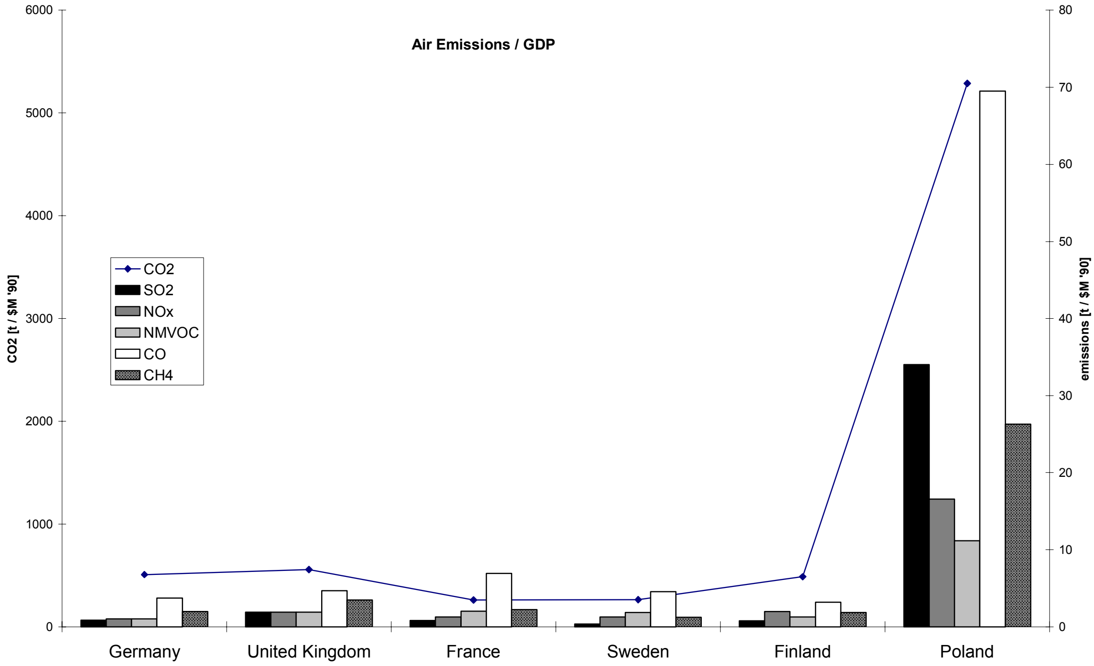


FIG. 21. Comparison of emissions per GDP unit.

Most airborne emissions come from stationary sources. As a whole, the energy supply sector contributes about 75% of national SO_2 emissions, and about 60% of the NO_x and CO_2 emissions. Coal use (including lignite) alone in Poland accounts for almost 90% SO_2 emissions, more than 70% of NO_x emissions, and over 98% of particulate emissions.

With the political changes since 1989, environmental issues have taken on greater importance. Improving environment protection is stated to be one of the most important targets of the Polish Government Policy. Policies promoting environmental protection have been introduced, and Poland's economic "shock therapy" has closed down many inefficient, polluting factories. The document "National Environmental Policy" (approved by Parliament in 1991), and the implementation programme (approved by Parliament in 1995) form the basis for the Polish environmental policy, including investment projects until the year 2000. The association of Poland in the western communities has had an additional positive impact on its environmental strategy. Poland is presently at an advanced stage of harmonisation of its environmental legislation with the EU legislation. Poland signed a number of international conventions on the reduction of environmental emissions, among them the following conventions on air protection can be noted:

1. Poland ratified the **Geneva Convention on Long-Range Transboundary Air Pollution** (1979), in 1985. The protocol on reduction of nitrogen oxide emissions was signed in 1988. Poland was not a signatory to the Helsinki protocol on sulphur emission reduction (1985), but it conforms to its provisions. **The Second Sulphur Protocol** (Oslo) was signed by Poland in 1994.
2. The **UN Framework Convention on Climate Change** (UNFCCC) was signed by Poland in 1994, and the **Kyoto Protocol** in 1998. The first governmental report on the implementation of the Convention was submitted in 1995.
3. The **Vienna Convention on the Protection of the Ozone Layer** has been binding on Poland since 1990. Meanwhile Poland signed the **London** (1990) and **Copenhagen** (1992) **Amendments** and ratified them in October 1996.

The Polish Government has set several other goals that are essential in achieving a healthier environment. Short to medium term priorities include:

- Restructuring the energy supply mix, mainly by switching from coal to gas and increasing the use of renewable energy sources,
- Improving coal quality by constructing coal enrichment facilities and coal desulphurisation,
- Improving energy efficiency and promotion of energy conservation by increasing energy prices, and
- Reducing the growing adverse environmental impacts of transportation.

Long-term priorities through the year 2020 include:

- Full elimination of individual coal furnaces in urban areas and health resorts,
- Introduction of catalytic converters in all cars produced and those in use,
- Reduction of SO_2 and NO_x emissions by 80%,
- Elimination of the use of freons and halons, and
- Reduction of carbon dioxide emissions to the level agreed upon at the international forum.

In addition, Poland has officially adopted the "polluter pays" and "user pays" principles of environmental protection. Penalties for polluting the environment are collected by Poland's National Fund for Environmental Protection and Water Management, which has become one of the major financing sources for environmental ventures.

As a result, after ten years of the transformation process, there are quite a few positive achievements recorded in Poland. River pollution has decreased by approximately 50% (in terms of the contaminants discharged), and the quality of air has improved remarkably. Major air pollutant emissions have been significantly reduced between 1988 and 1997: SO_2 emissions were cut by half, particulates by almost 60% and NO_x by 30% (Fig. 22). Poland is not taking these emission reduction estimates for granted, however. In order to meet EU standards concerning emissions of SO_2, NO_x, and particulates, the Polish government in 1998 enacted new environmental regulations for emissions from boilers, requiring installation of sulphur control technologies such as scrubbers or fluidised bed boilers. There is an especially strong commitment to modernise the country's obsolete, inefficient electricity and co-generation facilities. Since 1994, there has been increased financial investment in equipment for fuel desulphurisation, as well as for the reduction of dust emissions, nitrogen oxides and other toxic substances. The World Bank is financing desulphurisation equipment installations for the Dolna Odra power plant and the Rybnik combined heat and power plant, and notable investments have been made to reduce SO_2 emissions from Poland's two largest power plants, Belchatów and Turów. By 2005, compared to 1990, more than 95% of installed capacity will have new or modernised particulate control equipment, around 90% will have some type of control for NO_x emissions, and above 50% will control SO_2 emissions. Just between 1992 and 2000, about 9000 MW of electricity-generating capacity was retrofitted to increase energy efficiency and improve environmental protection.

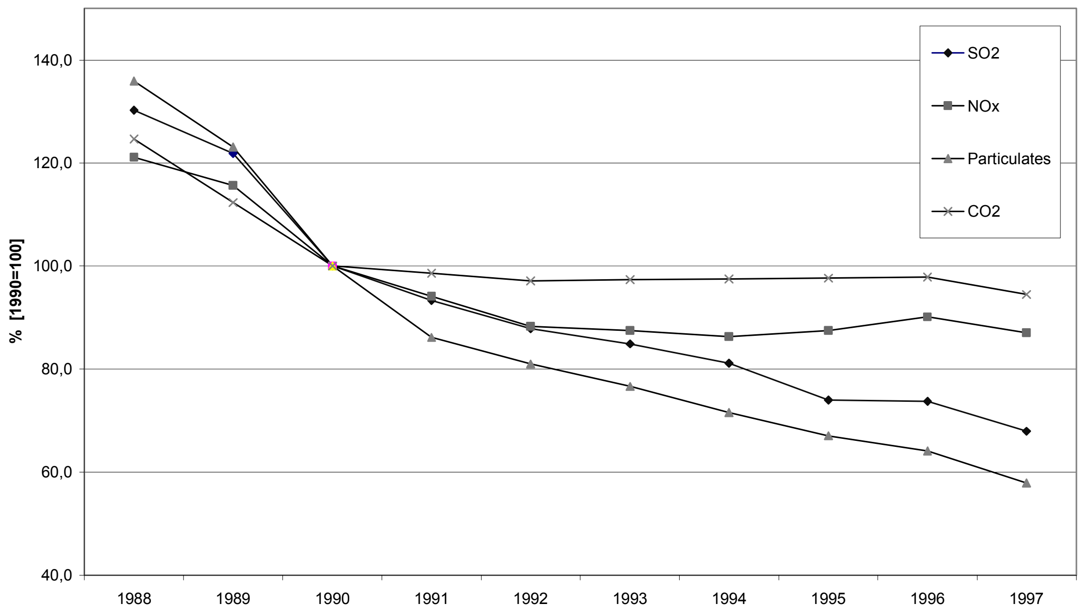


FIG. 22. Air pollutant emission indices in 1988-1997 (1990 = 100).

In contrast to Poland's industrial sector, which is emitting less carbon and other toxic substances than it used to, the transportation sector has shown a significant increase in emissions of atmospheric pollutants. Poland has experienced a dynamic rise in the number of cars since the late 1980s. Between 1989 and 1995 the number of personal automobiles in

Poland jumped by approximately 70% while the number of trucks increased by approximately 40%. At first, emissions rose since most of these cars were old and not equipped with modern environmental technologies, but the introduction of unleaded gasoline has tempered this rise. Increased emissions from the transportation sector are likely to continue, although the introduction of catalytic converters should help to some extent.

Although the shift is underway in Poland from coal mining and heavy industry to modern services and lighter branches of production, the predominance of coal in Poland's energy production and consumption mix in combination with growing individual consumption of energy and fuels as well as uninhibited motorization growth will continue to pose increasing threats to the environment. Despite Poland's surging economy, one of the major concerns is the country's ability to finance cleanup projects in order to meet EU environmental criteria for membership. Poland still has a long way to go to catch up. To help finance environmental protection and restoration in the future, Poland has sought debt-for-environment swaps, proposing that a portion of Poland's debt be redirected from lenders into an Ecofund.

3. ENERGY DEMAND PROJECTION

This section presents the projections of energy demand that were developed in this project. These projections provided the basis for the Governmental report entitled “Energy Policy Guidelines till 2020” [1] and its main attachment “Long-term Energy Demand and Supply Forecast till 2020” [2]. The developed energy demand projections till 2020 are grouped into two interdependent categories:

- **Final energy demand,** i.e. energy consumption in all economy sectors excluding the energy sector – manufacturing, construction, transport, agriculture, commercial and residential; and
- **Primary energy demand,** i.e. total final energy consumption (including the energy sector) augmented by losses in energy transformation processes, own use in the energy sector (power plants, refineries, coal mining, etc.), and transportation and distribution losses.

To deal with the many uncertainties inherent in a transition economy, a scenario approach to socio-economic development of the country was chosen as the basis for the analysis. The adopted scenarios are characterised by differing assumptions for the main macroeconomic variables that are closely related to changes within the international neighbourhood and might have a fundamental impact on the pace of Polish economy development in the next two decades.

The process of Poland’s integration with the European Union is certainly one of the most influential external factors. In consequence, great attention was paid to assuring that the basic assumptions, related to the macroeconomic development in all scenarios, are in good accordance with the corresponding scenarios that had been already developed by experts of the European Commission for the member countries.

The outcomes of these analyses should be interpreted neither as “compulsory plans” nor as most likely predictions. The study simply provides information about the amount and structure of the possible final demand, subject to the dynamics of change of different phenomena characterising the particular scenario. It also informs about conditions and possibilities of meeting the fuel and energy demand while fulfilling requirements of environmental protection. In short, the study is aimed at providing policy makers with a clearer insight into the driving forces and impacts of key policy decisions on Polish energy policy over the next 20 years.

3.1. Macroeconomic scenarios

Long-term fuel and energy demand projections are based on three different scenarios of macroeconomic development in Poland till the year 2020. The scenarios developed specifically for this study are based on model simulations carried out by two independent research centres — the Institute of Development and Strategic Studies (IRiSS) and the Polish Foundation of Energy Efficiency (FEWE) [6, 7], as well as on consultations and workshop discussions. These scenarios take into account different paces of growth of the Polish economy in the transition period and its capability of adapting to various external conditions.

Because the integration into the European Union is one of the main political objectives of the Polish Government, three EU scenarios (Battlefield, Conventional Wisdom and Forum) developed by the European Commission [8] were used as the starting point to develop scenarios for Poland. The EU scenarios provide quantitative time-series on a wide range of macro-economic indicators for the EU as a whole, like the price of oil and gas on the world market, the economic growth within Europe, general technological innovation, and labour and capital productivity. On the basis of the EU-scenarios, further translation of quantitative and qualitative macro-economic indicators to Poland was made. In all scenarios the basic assumptions concerning expected economic developments in the near future, contained in Polish Government documents, are preserved, including a gradual adjustment of the Polish economy to existing standards in the OECD and the EU countries. The main assumptions of the economic scenarios employed in the analysis are:

- **The Survival scenario** – This scenario corresponds to the EU Battlefield scenario, which assumes protectionism, fragmentation and low economic growth, combined with strong government intervention and an active social policy. The Polish economy cannot generate firm foundations for a continuous growth, restructuring proceeds very slowly and advanced technologies play only a minor role in the economy. Economic and social reforms fail and the economy is burdened with high expenditures, needed to maintain the current standard of living. Lack of investment funds prevents advancing the economic condition. The savings rate is low. This scenario has a clear warning character. Average annual economic growth settles down around 2.3%, making the bridging of the gap with EU economies impossible. The unemployment rate decreases slightly through 2005, mainly due to a necessity to protect the labour market. It rises rapidly after that and stabilises at a level of about 14%. Under these conditions the integration of Poland into the European Union is delayed till after 2010, if it would be possible at all.
- **The Reference scenario** – The economic growth is consistent with the EU Conventional Wisdom scenario, which denotes the 'business as usual' world. The world political situation and economic development is stable and no significant disturbances or sudden changes take place. Although some progress is made, many of the world's structural, social, and economic problems remain. Despite that, Poland continues its beneficial changes initiated in the early nineties. Restructuring in heavy and mining industry is slow but eventually reaches its goal. A certain delay in the undertaking of structural reforms results in an increased unemployment rate to about 14.3% by 2020. The pursued politics of "gentle changes" to the GDP structure leads to fast exhaustion of the simple development reserves, causing a permanent drop of the average GDP growth rate to about 4%. Poland, however, does not lose the chance of joining the EU, though this would take place with a several year delay (around 2010). At that time, new important changes in the employment and GDP structure would be necessary.
- **The Progress-Plus scenario** – In this scenario that is based on the EU Forum scenario global political consensus enhances economic growth. The European integration stimulates technological innovation. The prospering economy and high environmental awareness result in a largely ecologically influenced energy policy. In Poland, following an active and effective Government's policy, a desirable behaviour of all

main economic actors is realized and a deep restructuring of economy takes place. The GDP structure changes significantly, due to favourable qualitative changes in agriculture and industry (creating conditions for implementation of advanced technologies, especially the information technology) and there is an increasing share of services in generating GDP growth. In consequence, general labour efficiency substantially improves while the primary energy productivity experiences almost a three-fold increase. These fundamental changes allow for a sustained high average annual growth rate of about 5.5%. Poland becomes a member of the EU before 2005. This fact facilitates the continuation of favourable development trends, and even accelerates them to some extent.

The scenarios are further characterised in Table 3.

TABLE 3. Selected macroeconomic and energy indices

YEARS		1997	2005	2010	2015	2020
Population[a], million		38.66	39.26	39.93	40.32	40.34
Population (Progress-plus), million		-	38.63	38.79	39.00	39.00
Available labour force[b], million		17.85	18.10	18.35	18.25	18.40
Energy intensity of GDP, kgoe/zł'95	SURVIVAL	0.309	0.253	0.237	0.216	0.193
	REFERENCE		0.212	0.181	0.158	0.140
	PROGRESS-PLUS		0.199	0.155	0.124	0.102
Electricity intensity of GDP, kW·h/zł'95	SURVIVAL	0.405	0.386	0.384	0.365	0.348
	REFERENCE		0.334	0.311	0.288	0.281
	PROGRESS-PLUS		0.309	0.260	0.221	0.199
Unemployment rate, %	SURVIVAL	11.2	10.0	14.0	14.0	14.0
	REFERENCE		10.9	12.3	13.4	14.3
	PROGRESS-PLUS		9.2	8.9	8.5	7.6
YEARS			1997–2005	2006–2010	2011–2015	2016–2020
Average annual GDP growth, %	SURVIVAL		2.4	1.8	2.3	2.7
	REFERENCE		4.8	3.7	3.4	3.2
	PROGRESS-PLUS		5.7	6.3	5.5	5.1
Investments, %	SURVIVAL		6.8	1.6	1.8	2.0
	REFERENCE		9.0	2.1	2.0	1.8
	PROGRESS-PLUS		12.4	8.3	4.6	3.3
Population income growth, %	SURVIVAL		2.4	1.9	1.9	2.7
	REFERENCE		5.1	3.7	3.4	3.2
	PROGRESS-PLUS		6.7	5.3	5.1	4.5

[a] The population forecast for the Survival and Reference scenario was identical, adopted from [6].
[b] The same forecast of the available labour force was used in all scenarios.

Table 3 includes a demographic forecast and selected macroeconomic parameters for five-year intervals. Among the presented scenarios, The Progress-Plus scenario deserves special attention, since it is based on most recent information was used (hence the term “Plus”). This includes information on the following:

- A new Central Office of Statistics forecast of the population growth till 2030 [9];
- Latest information about tendencies of change of Gross Domestic Product (GDP), values added, and production volumes in the most energy-intensive sectors of the national economy (heavy and petro-chemical industry, construction, transport); and
- Verified, detailed energy balances for the country including data for all economy sectors and branches, as well as the up-dated information about the use of electrical appliances in the residential sector.

The most frequently used measure of economic development is the annual GDP (added value) growth. The forecast of this index – including the historical data from 1985 – in the considered scenarios is shown in Fig. 23. The average annual GDP growth rates in the period 1997–2020 under the Survival, Reference and Progress-Plus scenario are 2,3%, 4%, and 5.5% respectively. The growth of population income closely follows the GDP growth. Finally, the investments growth rate in Poland is 3.5%, 4.5%, and 8% correspondingly.

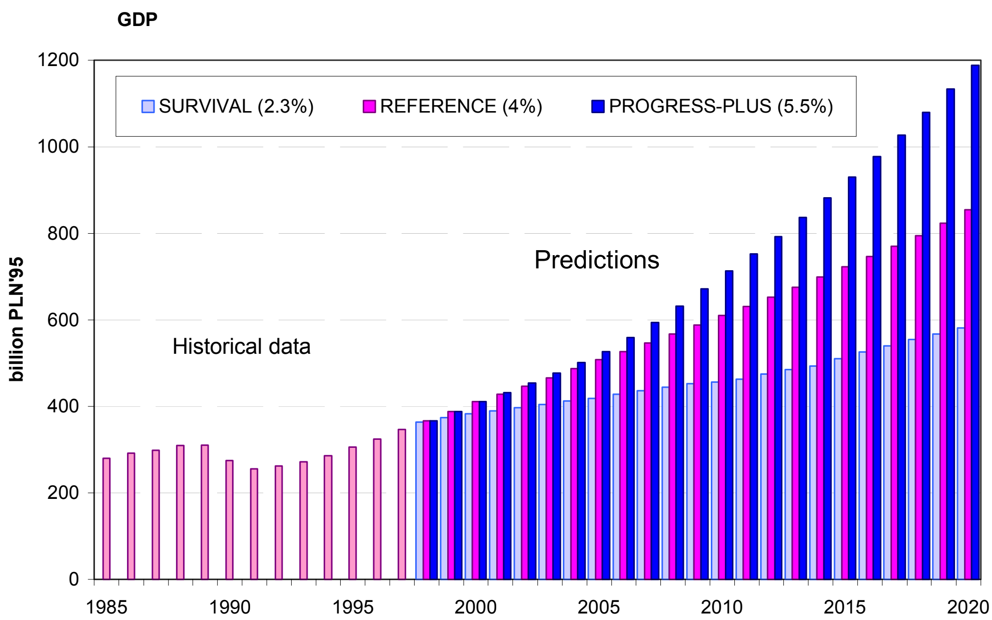


FIG. 23. Macroeconomic scenarios – GDP growth.

However, the level of future energy demand is influenced not only by GDP growth, but also by its structure, which differs in each of the scenarios. This is illustrated in Table 4, showing changes of the value added generated by different economic sectors, and in Table 5 that compares the GDP structure in 1997 and 2020.

TABLE 4. Development of added values by economy sector (1997 = 1)

Scenario	Economy Sector	1997	2005	2010	2015	2020
SURVIVAL	Agriculture	1	1.10	1.16	1.30	1.45
	Manufacturing&Construction	1	1.49	1.73	2.00	2.30
	Commercial&Services	1	1.07	1.14	1.26	2.46
	Transport	1	1.30	1.46	2.53	2.64
	Energy Sector	1	1.18	1.36	2.52	1.72
	GDP	1	1.21	1.32	1.47	1.67
REFERENCE	Agriculture	1	1.17	1.36	1.59	1.84
	Manufacturing&Construction	1	1.48	2.74	2.04	2.40
	Commercial&Services	1	1.48	1.78	2.07	2.48
	Transport	1	1.46	1.94	2.27	2.61
	Energy Sector	1	1.26	1.46	1.72	2.07
	GDP	1	1.46	1.74	2.06	2.63
PROGRESS-PLUS	Agriculture	1	1.08	1.15	1.22	1.30
	Manufacturing&Construction	1	1.63	2.29	3.02	3.87
	Commercial&Services	1	1.39	1.90	2.50	3.23
	Transport	1	1.74	2.39	3.11	4.01
	Energy Sector	1	1.22	1.49	1.84	2.22
	GDP	1	1.52	2.06	2.68	3.43

TABLE 5. GDP structure

	1997	2020		
		SURVIVAL	REFERENCE	PROGRESS-PLUS
GDP, billion PLN ’95	346.8	580.8	854.8	1188.2
GDP, %, in which:	100	100	100	100
Agriculture	5.7	4.9	4.2	2.2
Manufacturing & Construction	25.8	35.5	25.1	29.2
Energy Sector	6.2	6.4	5.2	4.0
Transport	3.9	3.8	3.8	4.6
Commercial & Services	44.3	38.6	44.6	46.5

As shown, the GDP growth in the study period would be quite different under different scenarios. As compared to 1997, GPD increases by two thirds in 2020 in the Survival scenario, two and a half time in the Reference scenario, and about three and a half time under the Progress-Plus scenario. However, due to switches in the GDP structure towards less energy intensive activities, as well as more effective end-use of energy (especially large energy savings can be obtained in the heat supply and use), these large differences in GDP growths will not have significant influences on final energy demand projections. As it will be shown, final energy demand growth till 2020 stays below 13% under all scenarios.

3.2. Final energy demand projections

3.2.1. Introduction

Future final energy demand depends, first of all, on the level of economic activities as well as the overall wealth of the society. These are usual parameters defined in the macroeconomic forecasts. Demographic changes and the present state of national economy are equally important.

For this study, projections of national energy demand were determined under the assumption that, due to integration processes, the basic mechanisms of the Polish economy would gradually converge to those existing in well-developed market economies. Therefore, it was accepted that the functional dependence between final energy demand and changes of macroeconomic parameters could be based on the corresponding relationships observed in these countries. A regression analysis method, based on the comparative studies of international data, was implemented in combination with the so-called the end-use energy method.

In all computations, different means were considered to speed up efficiency gains and the conservation of energy. They made it possible to bridge the technological gap during the system transformation. The base energy balance of the country, prepared in accordance with the Polish Classification System (EKD), was chosen for the year 1997 [10], taking additionally into account the preliminary energy balance for the year 1998.

3.2.2. Methodology[2]

Energy end-use projections were performed simultaneously in two planes:

- final energy demand forecast (top-down approach), and
- useful energy demand forecast (bottom-up approach).

The final energy demand forecast under the Reference scenario was used to calibrate parameters in the modelling of useful energy demand.

Both useful and final energy demand forecast methods were based on international statistical data, since historical data for Poland could not be applied. Data from selected west European countries were used as a surrogate [10]: data from „Euro-4” countries (France, western Germany, Italy, United Kingdom) for the useful demand forecast, and from Finland, France, Germany, Sweden, and United Kingdom for the final energy forecast.

All simulations were performed with economy sectors aggregated as follows:

1. Industry, including:
   - iron and steel,
   - chemical,
   - mineral,
   - other industries (including construction),

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[2] ED. NOTE: the methodology to be reviewed/questioned/clarified?

2. Agriculture,
3. Transport,
4. Services, and
5. Households.

3.2.2.1. Projection of useful energy demand

The following end-use energy categories were considered:

Industry:

- Direct (furnace) heat,
- Medium temperature indirect heat,
- Low temperature indirect heat, and
- Electricity.

Residential and commercial sectors:

- Space heating,
- Water heating,
- Cooking,
- Lighting, and
- Electrical appliances.

Transport:

- Railway passengers,
- Railway freight,
- Road passengers,
- Road freight, and
- Other transport.

Energy demand growth rates were calculated using the following formula[3]:

$$\Delta E = \lambda \times \Delta M \tag{1}$$

where:

ΔM – exogenous variable (driving force) growth rate,
λ – elasticity.

Exogenous variables were chosen as follows:

- for industry and commercial sectors – value added,
- for households and passenger transport – individual income per capita, and

[3] For space heating the formula $\Delta E = \lambda \times (\Delta M - W)$ was applied, where W represents reduction in heat requirements due to improved building insulation [4].

— for freight transport – value added in industry including hard coal industry.

3.2.2.2. Projection of final energy demand

To estimate the future relationship between economic performance and energy consumption, a regression analysis was performed. Specifications and estimation of regression equation parameters are based on analogous time series data for the selected countries. Although data for the period 1970 through 1995 were available, data for 1970 to 1975 were omitted in order to avoid anomalies that resulted from the first oil crisis.

Energy demand forecasts by economy sector were made with the use of the following formula:

$$\Delta E_{i,k} = (1+\Delta A)^{\alpha} \times (1+\Delta B)^{\beta} \times Q - 1 \tag{2}$$

where i denotes energy carrier, k stands for the national economic sector, A and B are economic variables, α, β and Q are parameters, and Δ is a difference operator. Q is a parameter describing, excluding A and B, all other factors affecting the energy demand growth. It includes both technical and organisational standards of the given sector as well as programs for energy use conservation.

According to the adopted assumptions, dependent variables of the model equations are electricity and all other energy carriers used in different economic sectors. The following were taken as the independent macroeconomic variables:

— GDP – gross domestic product,
— VA – value added in a particular sector,
— INV – investment layouts in a particular sector,
— INV_{-1} – investment layouts with a one year lag, and
— POP – Population.

3.2.2.3. Algorithm for final energy demand projection

The procedure for final energy demand projections is an iterative one, consisting of the following steps:

1. Evaluation of final energy demand by economy sector using formula (2),
2. Adjustment of the predicted demand growth by taking into account acceleration in energy efficiency improvement,
3. Calculation of useful energy demand growth rates using formula (1),
4. Setting the base-year quantities and growth rates of useful energy demand (under the Reference Scenario), as input into the BALANCE module of ENPEP,
5. By using BALANCE, calculation of final energy demands for electricity and other energy carriers, and next aggregating the results by sector,
6. Verification and calibration of final energy projections. If the values computed in step 5 differ significantly (above 20%) of those determined in step 2, the whole procedure is repeated, after appropriate adjustment of both, variables and parameters in the demand model as well as the price

sensitivities in the BALANCE module. If, on the other hand, the differences are not large, an adjustment of parameters λ is made, in order to match final energy demands computed in steps 2 and 5 through the last year of the study period.

The above approach makes it possible to mutual converge the bottom-up and top-down procedures for final energy demand projections.

3.2.3. Results – Projections of final energy demand

The results of final energy demand projections are presented in Tables 6–11 and in Figs 24–27.

TABLE 6. Final energy demand, Mtoe

Scenario	Economy Sector	1997	2005	2010	2015	2020
SURVIVAL	Manufacturing&Construction		28.8	29.4	30.0	30.5
	Transport		10.3	10.4	10.9	11.3
	Agriculture		4.9	5.0	5.2	5.3
	Services		4.1	4.3	4.5	4.8
	Households		19.7	20.0	20.1	20.3
	TOTAL		67.7	69.1	70.8	72.3
REFERENCE	Manufacturing&Construction	29.9	28.7	29.5	30.1	30.7
	Transport	9.9	10.5	10.8	11.6	12.4
	Agriculture	5.1	4.9	5.0	5.3	5.3
	Services	4.4	4.3	4.7	5.2	5.9
	Households	22.7	19.7	20.3	20.7	21.2
	TOTAL	72.0	68.1	70.3	72.9	75.6
PROGRESS-PLUS	Manufacturing&Construction		27.6	29.4	31.0	32.7
	Transport		11.0	12.2	13.7	15.6
	Agriculture		4.6	4.4	4.3	4.2
	Services		4.2	4.8	5.5	6.5
	Households		19.8	20.5	21.2	22.0
	TOTAL		67.2	71.3	75.6	80.9

TABLE 7. Final energy demand (excluding electricity) forecast [Mtoe]

Scenario	Economy Sector	1997	2005	2010	2015	2020
SURVIVAL	Manufacturing & Construction		23.5	23.6	23.6	23.4
	Transport		9.9	9.9	10.4	10.8
	Agriculture		4.4	4.5	4.6	4.7
	Services		2.6	2.5	2.5	2.4
	Households		17.9	18.0	18.0	18.0
	TOTAL		58.2	58.5	59.1	59.3
REFERENCE	Manufacturing & Construction	25.7	23.5	23.5	23.5	23.2
	Transport	9.5	10.1	10.3	11.1	11.1
	Agriculture	4.6	4.4	4.5	4.6	4.7
	Services	3.1	2.6	2.5	2.5	2.4
	Households	21.0	17.7	17.9	17.9	17.8
	TOTAL	63.8	58.2	58.8	59.6	60.0
PROGRESS-PLUS	Manufacturing & Construction		22.6	23.8	24.8	26.0
	Transport		10.6	11.7	13.1	14.9
	Agriculture		4.1	3.9	3.8	3.6
	Services		2.6	2.5	2.5	2.4
	Households		17.9	18.0	18.1	18.1
	TOTAL		57.7	60.0	62.3	65.0

TABLE 8. Final electricity demand forecast, TW·h

Scenario	Economy Sector	1997	2005	2010	2015	2020
SURVIVAL	Manufacturing & Construction		60.8	67.5	74.8	82.7
	Transport		5.1	5.4	5.8	6.1
	Agriculture		5.9	6.4	7.1	7.6
	Services		18.1	21.2	23.9	27.5
	Households		20.9	23.0	24.7	26.9
	TOTAL		110.9	123.5	136.2	150.8
REFERENCE	Manufacturing & Construction	48.8	61.4	68.8	77.3	86.6
	Transport	4.7	5.1	5.4	5.8	6.1
	Agriculture	5.4	5.9	6.5	7.2	7.8
	Services	16.1	20.0	25.3	31.7	40.6
	Households	19.8	23.0	27.5	32.7	39.8
	TOTAL	94.7	115.4	133.5	154.6	180.9
PROGRESS-PLUS	Manufacturing & Construction		57.2	64.4	71.2	78.0
	Transport		5.7	6.4	7.2	8.2
	Agriculture		5.6	5.9	6.1	6.4
	Services		19.6	26.4	34.8	46.7
	Households		22.5	28.7	36.0	45.7
	TOTAL		110.6	131.8	155.3	185.0

TABLE 9. Final energy demand forecast by carrier, Mtoe

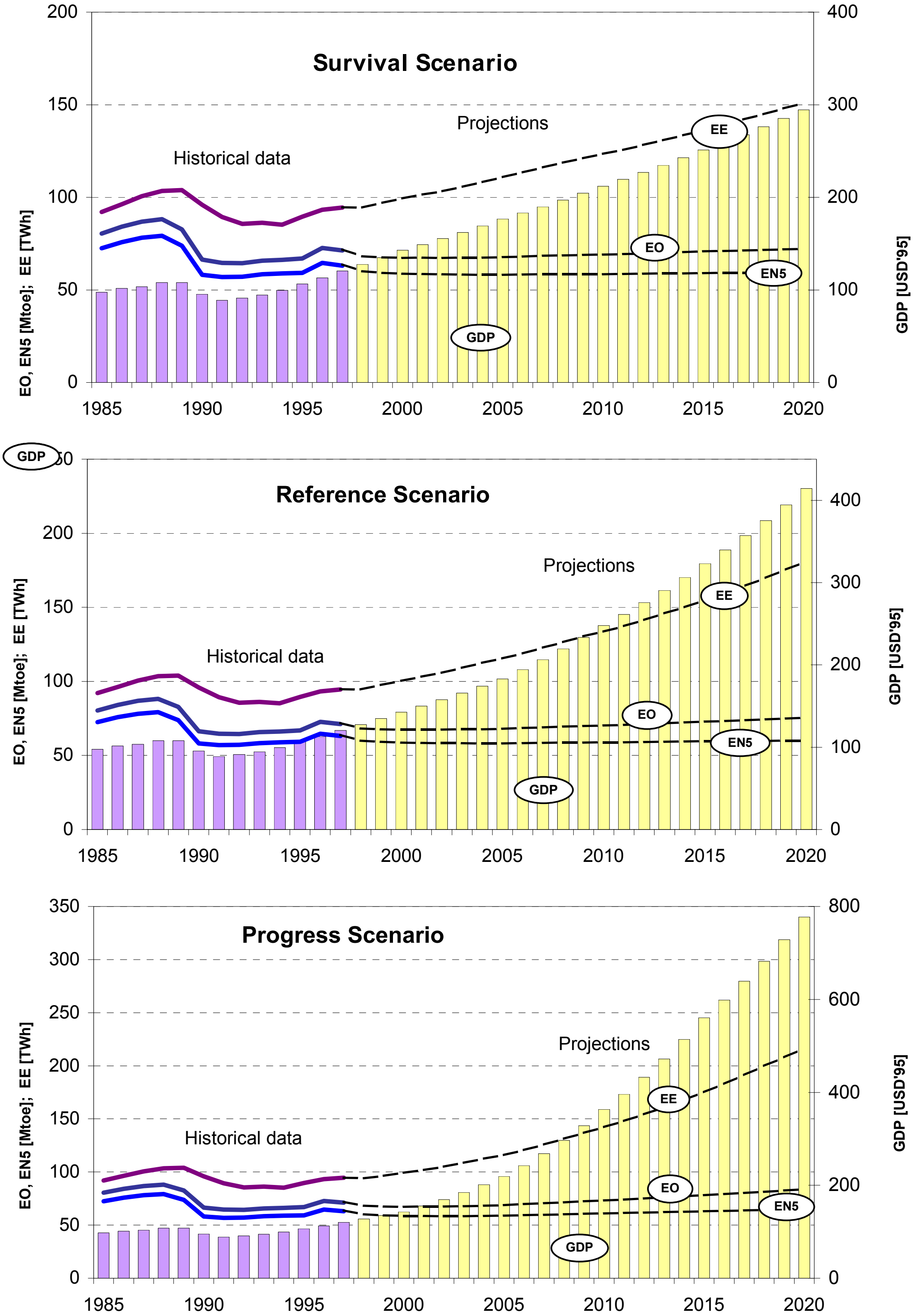
Scenario	Economy Sector	1997	2005	2010	2015	2020
SURVIVAL	Coal		17.0	16.0	15.4	15.0
	Petroleum products		19.2	18.9	19.2	19.6
	Natural gas		12.4	14.7	16.2	17.1
	Other fuels		4.3	4.2	4.2	4.2
	Electricity		9.5	10.6	11.7	13.0
	Heat		5.3	4.6	4.0	3.4
	TOTAL		67.7	69.1	70.8	72.3
REFERENCE	Coal	24.6	16.8	16.0	15.4	14.9
	Petroleum products	16.8	18.8	18.9	19.6	20.4
	Natural gas	10.1	12.9	15.3	16.8	17.5
	Other fuels	5.0	4.3	4.2	4.2	4.2
	Electricity	8.1	9.9	11.5	13.3	15.6
	Heat	7.4	5.2	4.2	3.5	3.0
	TOTAL	72.0	68.1	70.3	72.8	75.6
PROGRESS-PLUS	Coal		16.7	16.5	15.9	15.4
	Petroleum products		20.6	21.4	22.8	24.6
	Natural gas		10.5	12.4	14.1	15.5
	Other fuels		4.7	4.7	4.8	4.9
	Electricity		9.5	11.3	13.4	15.9
	Heat		5.3	4.9	4.7	4.6
	TOTAL		67.2	71.3	75.6	80.9

TABLE 10. Projected changes of final energy demand structure, %

Scenario	Economy Sector	1997	2005	2010	2015	2020
SURVIVAL	Coal		25.1	23.2	21.8	20.7
	Petroleum products		28.3	27.3	27.2	27.1
	Natural gas		18.3	21.3	23.0	23.7
	Other fuels		6.3	6.1	5.9	5.8
	Electricity		14.1	15.4	16.5	18.0
	Heat		7.9	6.7	5.6	4.7
	TOTAL		100.0	100.0	100.0	100.0
REFERENCE	Coal	34.1	24.8	22.8	21.1	19.7
	Petroleum products	23.3	27.7	26.9	27.0	27.0
	Natural gas	14.0	19.0	21.8	23.1	23.2
	Other fuels	7.0	6.3	6.0	5.8	5.6
	Electricity	11.3	14.6	16.3	18.3	20.6
	Heat	10.3	7.7	6.0	4.8	3.9
	TOTAL	100.0	100.0	100.0	100.0	100.0
PROGRESS-PLUS	Coal		24.8	23.1	21.1	19.1
	Petroleum products		30.6	30.1	30.1	30.4
	Natural gas		15.6	17.4	18.6	19.2
	Other fuels		6.9	6.6	6.3	6.0
	Electricity		14.1	15.9	17.7	19.7
	Heat		7.9	6.9	6.2	5.6
	TOTAL		100.0	100.0	100.0	100.0

TABLE 11. Projected changes of final electricity demand, %

Scenario	Economy Sector	1997	2005	2010	2015	2020
SURVIVAL	Manufacturing & Construction		54.8	54.6	54.9	54.8
	Transport		4.6	4.4	4.2	4.1
	Agriculture		5.3	5.2	5.2	5.0
	Services		16.4	17.1	17.5	18.2
	Households		18.8	18.6	18.1	17.9
	TOTAL		100.0	100.0	100.0	100.0
REFERENCE	Manufacturing & Construction	51.5	53.2	51.5	50.0	47.9
	Transport	4.9	4.5	4.1	3.7	3.4
	Agriculture	5.7	5.1	4.9	4.7	4.3
	Services	17.0	17.3	18.9	20.5	22.4
	Households	20.9	19.9	20.6	21.2	22.0
	TOTAL	100.0	100.0	100.0	100.0	100.0
PROGRESS-PLUS	Manufacturing & Construction		51.7	48.9	45.8	42.2
	Transport		5.1	4.9	4.7	4.4
	Agriculture		5.1	4.5	4.0	3.5
	Services		17.7	20.0	22.4	25.2
	Households		20.4	21.8	23.2	24.7
	TOTAL		100.0	100.0	100.0	100.0



EO - total final energy demand
EN5 - final energy demand excluding electricity
EE - final electricity demand

FIG. 24. Final energy demand projections.

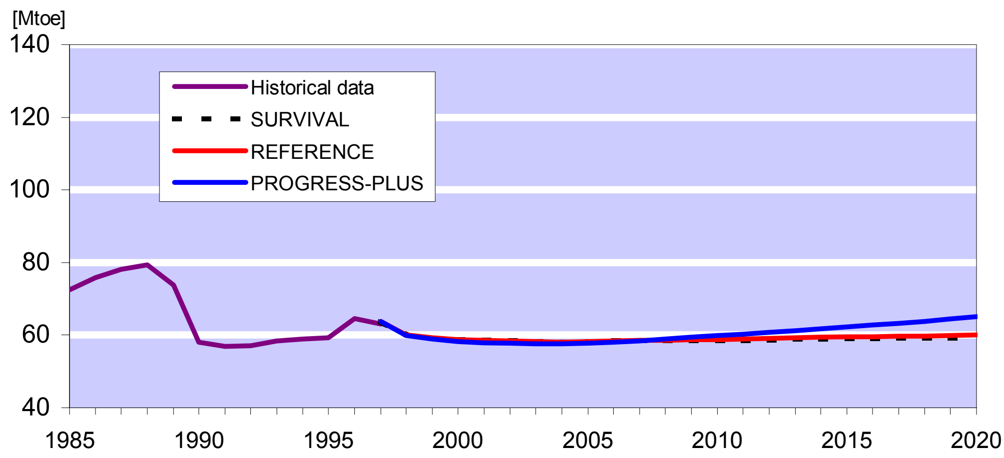


FIG. 25. Total final energy demand.

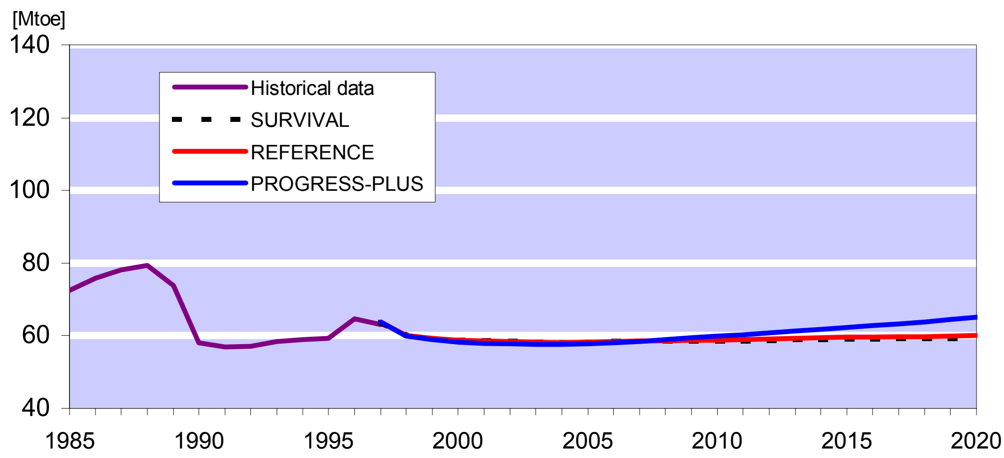


FIG. 26. Total final energy consumption excluding electricity.

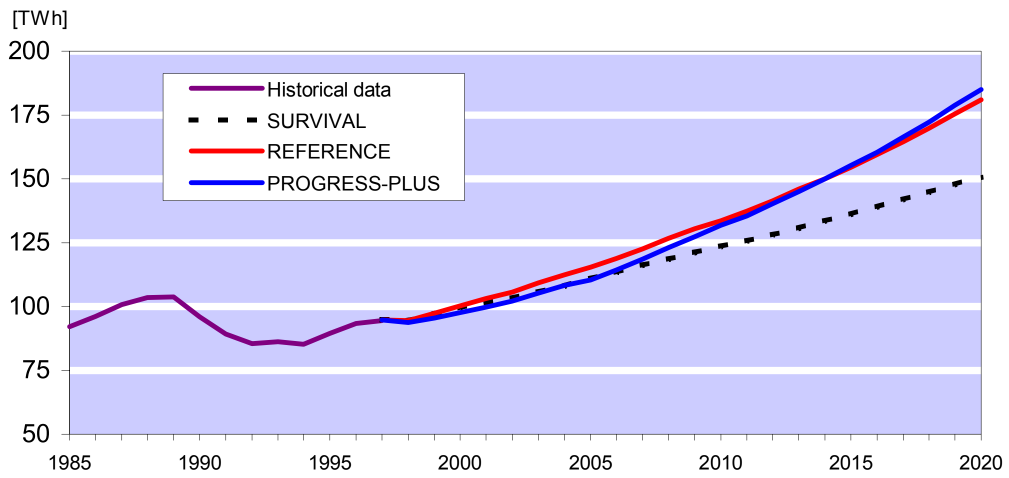


FIG. 27. Final electricity demand.

As shown, the projection includes final energy demand for the following sectors: manufacturing & construction, transport, agriculture, commercial, and residential. The following facts from the analysis are worth noting:

- Generally a small (virtually none in the Survival and 0.2% in the Reference scenario) to moderate (0.5% in the Progress-Plus) annual increase of final energy demand (FED) is projected (Table 6). FED growth rates are lower then the corresponding GDP growth rates due to the assumed increase in energy efficiency. It is noticeable that in all scenarios a 5–7% decrease of total energy demand is projected through the year 2005, and thereafter only a gradual increase is observed. The overall increase of the total FED in the period 1997-2020 under the Survival, Reference and Progress-Plus scenarios is 0.4%, 5%, and 12% respectively.

- Simultaneously, a gradual change of structure of sectoral energy demand can be observed (Table 7). The transport sector has the most significant increase in final energy demand (from about 13% in the Survival, through 25% in the Reference to over 50% increase in the Progress-Plus scenario), a fact which is, to a great extent, reflected in the growing demand for petroleum products. Next to transport is the commercial sector, reflecting the increase in the economic value of services. In contrast, energy demands in the industrial sector, including construction, as well as in the residential sector show almost no change during the study period.

- There is a clear change in the future structure of energy carriers (Tables 8 and 9). The results indicate that the total demand for the electrical energy will grow in all sectors faster then the total energy demand (2-3% average annual growth rate). A significant increase of electricity demand, two-fold in the residential and two and half-fold in the commercial sector, is expected under both the Reference and Progress-Plus scenarios. This increase reflects the relatively low initial level in use of electricity, a growing standard of living and the fact that electricity is not easily replaceable by other energy carriers. Demands for petroleum products and natural gas are also expected to increase, although at a somewhat more moderate annual growth rate: 0.85% (Survival and Reference), 1.7% (Progress) for petroleum products, and 2% (Progress), 2.4% (Survival, Reference) for natural gas. In contrast, coal consumption diminishes steadily in all scenarios at an average annual rate of 2%. Finally, there is also a marked decline in the use of district heat: an average annual drop of 2% in the Progress-Plus, and almost 4% in the Survival and Reference scenario. This happens mainly due to the generally lower demand for heat in the commercial/residential sector and industry (conservation and more efficient use of energy), and to some extent due to increased local heat production.

- In summary, the share of coal in the final energy demand in the period 1997–2020 is lower by more than 40% (from 34% to 20%), commercial heat is reduced by almost half (from 10% to about 5%), while at the same time the corresponding share of electricity doubles (from 11% to 20%) (Table 10). The share of natural gas and petroleum products also grows: gas from 14% in 1997 to 19% (Survival) or 23% (Progress) in 2020, and oil from 23% to 27% (Survival) or 30% (Progress). Although the overall change of the pattern of use of energy carriers brings the structure of the Polish final energy demand closer to the existing structure in the EU countries, significant differences will still remain. In 2020 the coal share in Poland remains much above the average of developed countries (about five times higher than the average value in the EU in 1996). In contrast, the share of petroleum derivatives and natural gas in the final energy mix is lower in Poland than in these countries.

— In spite of favourable temporal development, the final energy demand per capita in Poland will remain significantly lower than the corresponding values in the EU countries (Table 12). Moreover, it can be seen that even after two decades of development will not allow Poland to reach the existing level of per capita final energy use in the European Union. This is justifiable, since the projected average personal income in Poland in 2020 is still below that of EU countries.

TABLE 12. Per capita final energy demand in Poland and the European Union

	Poland				European Union[a]	
	1997	2020			1996	2020
		SURVIVAL	REFERENCE	PROGRESS-PLUS		
Total final energy demand, toe/cap	1.9	1.8	1.8	2.1	2.7	2.9
Total electricity demand, MW·h/cap	2.4	3.8	4.5	4.7	5.4	7.1
Electricity demand in household,s MW·h/cap	0.5	0.7	1.0	1.2	1.6	–

[a]Forecast of the International Energy Agency (IEA).

3.3. Primary energy demand projections

3.3.1. Methodology

3.3.1.1. Modelling overview and model interconnections

Figure 28 shows the three modules of the ENPEP package (ENPEP – Energy and Power Evaluation Program [11]) that were used for this study: ELECTRIC, BALANCE, IMPACTS. The ENPEP energy network was designed to simulate not only the technical features but also potential energy policy options such as the effects of taxes and subsidies on the Polish energy system. Other modules of ENPEP such as MACRO and DEMAND were not used since energy demand growth rates had been projected with domestic models that were designed by local experts to simulate the specific conditions of the Polish economy and its relations to future energy demands.

The configuration displayed in Fig. 28 was designed specifically for this study. Interactions and information flows between modules were necessary to simulate feedback among various aspects of energy and environmental systems. For this analysis the main module or focal point of the modelling system is the BALANCE module. This module contains a network of energy supply resources, conversion processes and demands. Its major function is to simulate energy markets such that all future energy demands are satisfied. The module also determines the price and demand equilibrium (i.e., balance) for meeting these future demands.

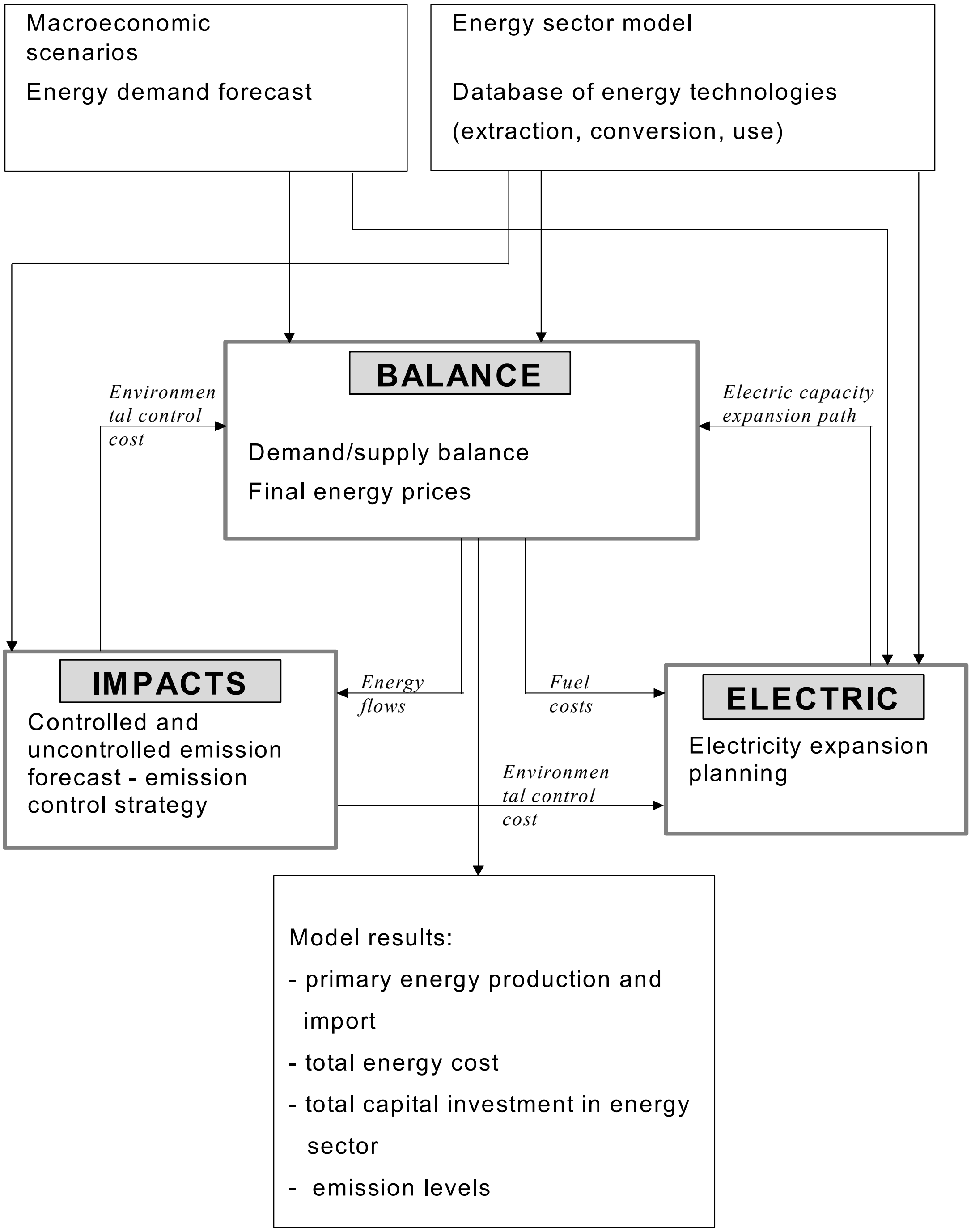


FIG. 28. ENPEP modules, exchange of model input data and results.

The BALANCE module requires detailed information on the electric sector and the additional generating resources that must be acquired to replace retired units and to meet growth in electricity demands. The least-cost capacity expansion plan is determined by the ELECTRIC module and transferred to BALANCE. Costs in the model include all investments, operating costs, and fuel expenditures over the study period. However, in order to determine this expansion path, ELECTRIC requires a forecast of fuel costs that are projected by BALANCE. To resolve any potential mismatches between electricity demand, fuel costs, and capacity expansion requirements between BALANCE and ELECTRIC, the two modules share information and require iterations, as detailed below.

Projections of energy flows at each node in the BALANCE module are input into IMPACTS module, which computes emissions of environmental residuals resulting from energy extraction, conversion, and consumption processes. IMPACTS estimates both controlled and uncontrolled emissions in the base year as well as future emission levels. The module enables analysts to estimate emission reductions that may occur when specific emission control measures are implemented. Since environmental control strategies and technologies effect capital expenditure for new unit construction, and both operational efficiencies and costs, control strategy information from IMPACTS is input into both the BALANCE and ELECTRIC modules.

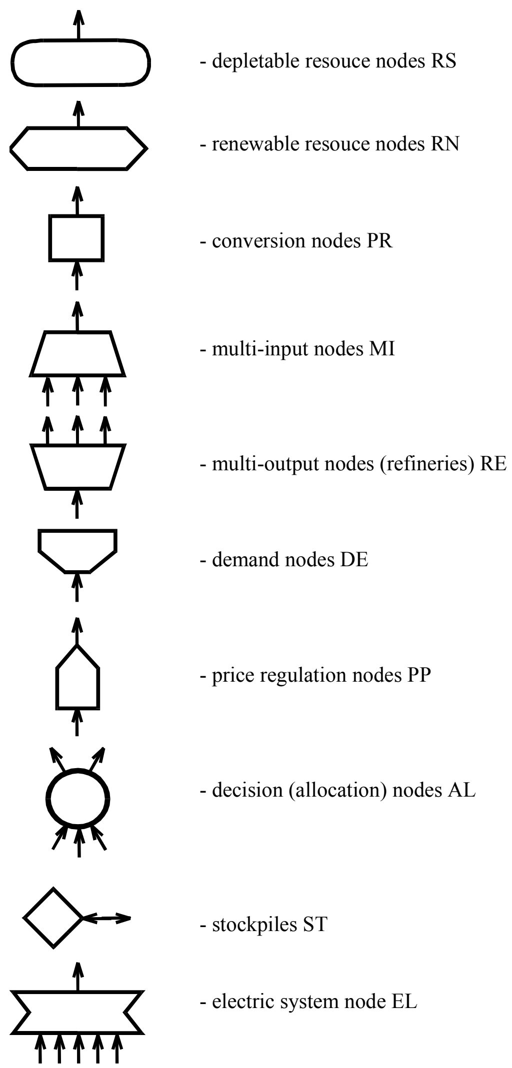


FIG. 29. Energy process nodes in the BALANCE module of ENPEP.

3.3.1.2. Energy demand and supply – BALANCE module

The main objective of the BALANCE module is to balance energy supply with demand. The module simulates the market behaviour of consumers, who tend to purchase the energy from the lowest cost supplier. BALANCE can represent both, the demand for final energy (e.g., coal, oil, and natural gas) as well as for useful forms of energy such as lighting and hot water. The simulation time step is one year, and a typical forecast period is 20–30 years.

The energy network consists of nodes that represent energy processes including energy extraction, conversion and use. Links in the network represent energy flows among these energy processes. Energy processes are shown in Fig. 29.

By convention the energy network is constructed such that demand nodes are located at the top, conversion processes in the middle, and energy supply resources at the bottom of the network. As an example, Fig. 30 shows the Polish energy network for hard coal.

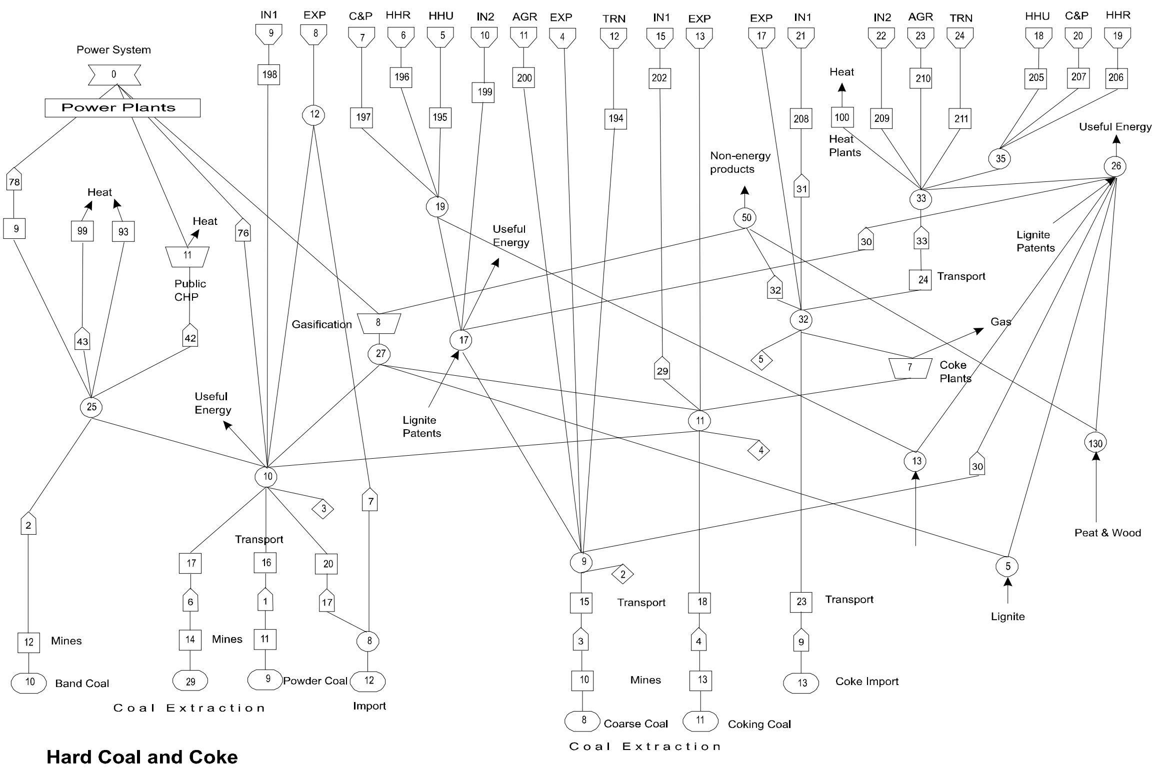


FIG. 30. Energy network – hard coal.

Once the network is constructed and historical energy flows are simulated, the module forecasts future energy demands and prices. Demands are simulated by computing energy flows from demand nodes through conversion processes down to supply resource nodes. This process is referred to as the "down-pass node sequence". Energy prices are computed by estimating costs for energy extraction and conversion processes through to the demand nodes. This process is referred to as the "up-pass sequence". In the down pass sequence, when the module computes energy flows, price estimates from the previous up pass sequence are used to determine the market shares of competing energy alternatives (i.e., input links). The market share is estimated by the following equation:

$$S_i = \frac{\left(1/(P_i \times Pm_i)\right)^{\gamma}}{\sum_i^n \left(1/(P_i \times Pm_i)\right)^{\gamma}} \quad (3)$$

where:

- S_i – market share for input link i,
- P – energy price,
- γ – price sensitivity coefficient,
- n – number of input links,
- Pm – premium multiplier.

Since market shares of energy are dependent on energy prices and energy prices are dependent on the quantity of fuel demands, the BALANCE Module uses an iterative process to bring network prices and quantities into equilibrium. The up pass and down pass sequences are repeated until the difference in energy flows (i.e., quantities) on network links change very little from one iteration (i.e., down pass) to the next and the processes converge to within a user specified tolerance level.

Since energy purchase decisions are not always solely based on price, premium multipliers are used in BALANCE to simulate the preference that consumers have for some commodities over others. Premium multipliers are used to simulate the market behaviour when competing resources have different levels of quality or convenience. It can also be used to simulate the market behaviour when high capital costs discourage the use of a specific technology or process.

In addition, the module uses a lag parameter to simulate the time that is required for prices and demands to reach an equilibrium or balance:

$$\overline{S}^{T} = \overline{S}^{T-1} + (\overline{S}^{T*} - \overline{S}^{T-1*}) \times Lag \quad (4)$$

where:

- $\overline{S}$ – vector of market shares,
- T – current year,
- $\overline{S}^{*}$ – intermediate value of the market shares vector determined by equation (3),
- Lag – lag parameter.

The lag parameter value ranges from 0 to 1. A value of 1 indicates there is no lag, and market shares respond immediately to current prices. A value of 0 indicates no response to prices and the base-year shares will be maintained throughout the study period. In general, capital-intensive industries have longer lag times than those that require relatively small capital investments.

3.3.1.3. Model aggregation

Because of network size limitations and data availability some energy related activities were aggregated. Network aggregation for economic sectors and energy carriers, shown in Figs 31 and 32 respectively, is based on the "Energy Balance for Poland in OECD, EUROSTSAT, and UN Statistics Format", an annual published by the EMA [10].

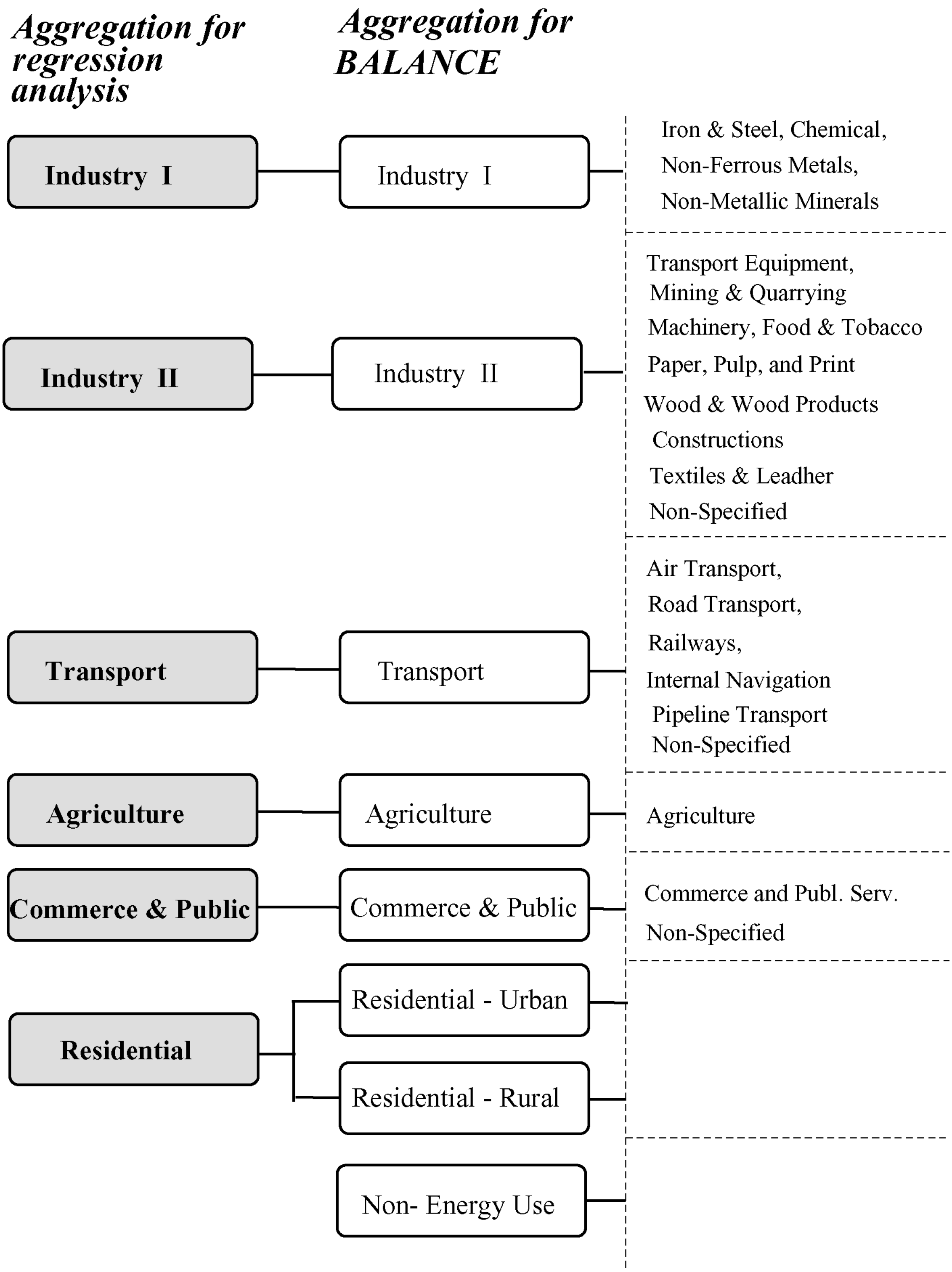


FIG. 31. Economy sectors aggregation.

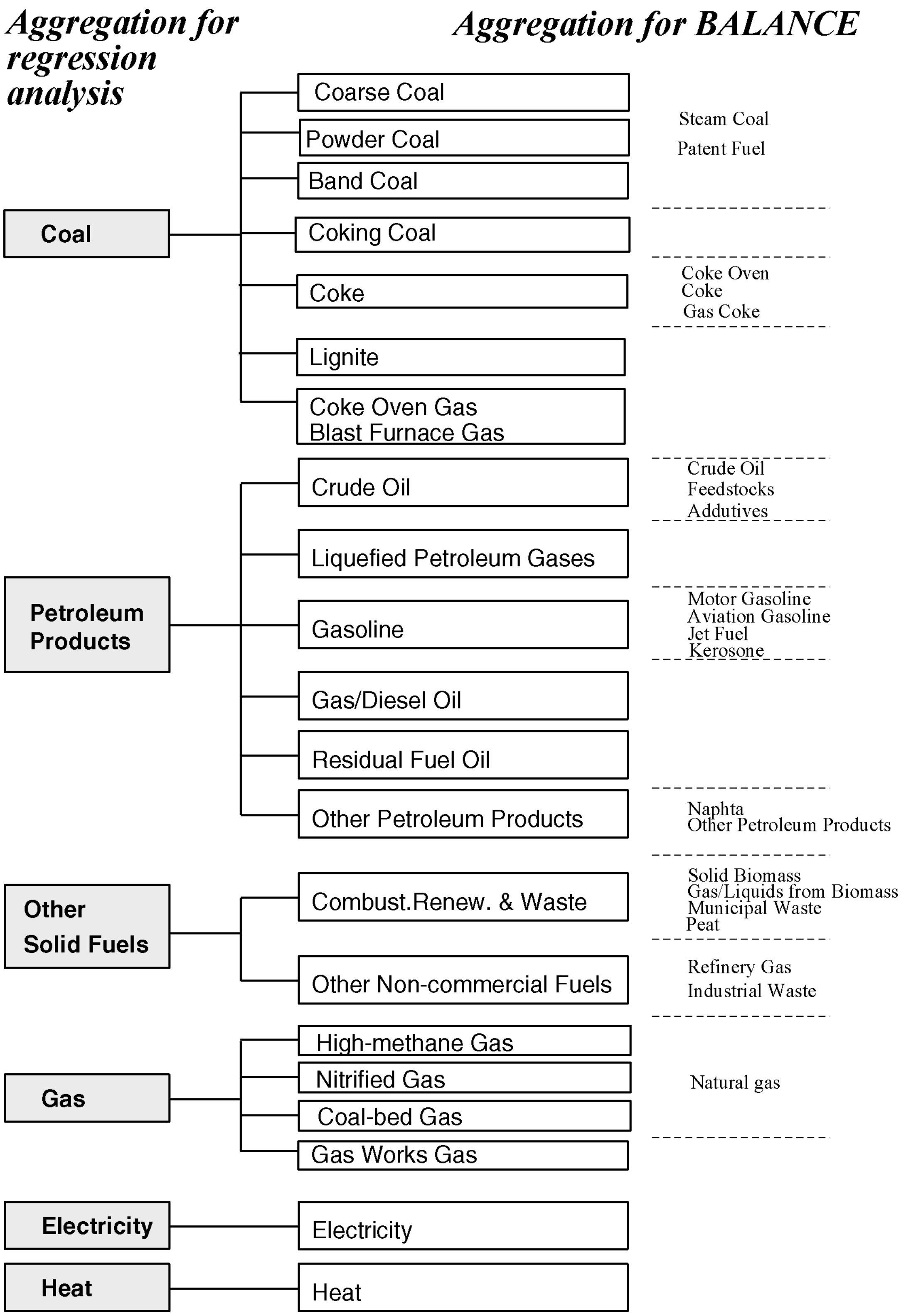


FIG. 32. Energy carriers aggregation.

The modelled energy network in BALANCE is rather large. The number of nodes by type in the Polish network is shown below:

—	depletable resource nodes	33
—	renewable resource nodes	7
—	allocation nodes	160
—	conversion nodes	200
—	multi-input nodes	3
—	demand nodes	119
—	multi-output nodes,	20
—	in which CHP plants	18
—	stockpiles	14
—	price regulation nodes	46
—	links	801

This large network size can be explained by the fact that both final energy demand and useful energy demand are simultaneously represented in the network. Final energy demand representation is used for balancing the network for the base year. Once the network is balanced, the demand is switched to useful demand and then the model is run with the useful energy demand representation.

3.3.1.4. Electric power sector simulation

The electric sector is represented in both the BALANCE and ELECTRIC modules. The BALANCE module simulates only the electric dispatch and requires deterministic values for all parameters, such as demand profiles and supply resources for all years of the study. The new capacity development in ENPEP is solved by ELECTRIC module. Since fuel prices (used in electric sector) are to some extent dependent on the generating capacity path and resultant fuel consumption, two or more iterations of the following steps must be performed until the BALANCE and ELECTRIC modules converge:

- Step 1: optimum plan of generating capacity expansion path is calculated by ELECTRIC based on forecasted fuel prices;
- Step 2: the plan is used in BALANCE, and new fuel prices for power plants are calculated;
- Step 3: new prices are used then in the ELECTRIC module and the generating capacity expansion path is updated.

The iteration process is completed when there are no further changes in the optimal generating capacity structure as determined by the ELECTRIC module. The demand for fuels is determined in the BALANCE module.

3.3.1.4.1. ELECTRIC module approach

The ELECTRIC module is a microcomputer version of Wien Automatic System Planning Package (WASP-III or WASP-III Plus [12]). The primary objective of WASP-III Plus is to determine the economically optimal generation expansion path for an electric utility system that reliably meets demand for electric power. It determines the capacity expansion path that leads to the minimum net present worth of the total expansion costs (investment, operation, fuel, unserved energy, etc.) over the study period subject to system reliability constraints, minimum and maximum reserve margins and financial and implementation feasibility. It utilises a probabilistic estimation of system operation (production costs, unserved energy cost, reliability) and a dynamic programming methodology for minimising costs of alternative system expansion paths.

ELECTRIC allows the treatment of the following interdependent parameters in an evaluation:

- load forecast characteristics;
- power generating system development;
- power plant capital, operating and fuel costs;
- power plants technical parameters;
- power supply reliability criteria; and
- power generating system operating practices.

The optimum is evaluated in terms of minimising total discounted costs. The cost (objective) function B_j attached to j-th expansion is represented by the following expression:

$$B_j = \sum_{t}^{T} \{ I_{j,t} - S_{j,t} + F_{j,t} + O_{j,t} + E_{j,t} \}, \tag{5}$$

where:

- T = length of the study period (total number of years),
- I = capital investment costs,
- S = salvage value of investment costs,
- F = fuel costs,
- O = non-fuel operation and maintenance costs, and
- E = cost of energy not served.

The optimal expansion plan is defined by: *minimum* B_j *among all* j.

The expansion path is determined by vector [K(t)] of all generating units operating in year t:

$$[K(t)]=K[(t-1)]+[A(t)]-[R(t)]+[G(t)], \tag{6}$$

where:

- [K(t-1)] = generating units in year t-1;
- [A(t)] = committed additions in year t;
- [R(t)] = committed retirements in year t; and
- [G(t)] = generating units added in year t from the list of candidate plants.

If applicable, the user may impose constraints on:

- reliability in terms of Loss-of-Load Probability index (LOLP): LOLP(K(t,i)) ≤ C(t,i) , where C(t,i) = limiting values for periods given as input data by the user;
- yearly fuel consumption by plant or group of plants (which actually is recalculated to daily amount); and
- maximum number of units from the list of candidates, feasible to be commissioned during one year.

The user must specify constraints on annual minimum and maximum reserve margins.

When fuel limits are imposed, a fuel substitute together with a substitution plant are used. A price for the substitution fuel which is much higher than the for the limited fuel acts as a penalty function. The dynamic optimisation algorithm chooses the expansion path such that candidate units that consume limited fuels penetrate the market less than unconstrained units. Therefore, units with limited fuel are substituted by candidates with production costs lower than the substitution plant.

Another important input into ELECTRIC is the cost of unserved energy. This parameter is used to penalise expansion paths that would result in high outage rates and low reliability.

3.3.1.4.2. Expansion candidates of the power system

In the base scenario it was assumed that electricity demand is met only by domestic power plants. However, additional scenarios with electricity imports from Sweden (DC cable) [13] and a projected direct current (DC) overhead line Russia – Germany have also been considered.

The existing thermal generation system consists of condensing units and co-generation plants, which usually are smaller in sizes. Except for some small facilities modelled as an aggregated unit, all major existing condensing plants are represented individually. Refurbishment and rehabilitation is modelled by retirements and additions of units in the fixed system (FIXSYS).

As candidates for new public power plants to satisfy demand growth and to replace decommissioned plants, the following technologies for power capacity expansion were considered:

TABLE 13. Expansion candidates for power generation

Hard coal fired:	800 MW Advanced Pulverised Fuel plant with wet FGD installation 300 MW Integrated Gasification Combined Cycle plant (IGCC) 200 MW Pressurised Fluidised Bed Combustion plant (PFBC)
Lignite fired:	800 MW Advanced Pulverised Fuel plant with wet FGD installation
Natural gas fired:	165 MW Gas Turbine peaking plant (GT) 480 MW Combined Cycle Gas Turbine plant (CCGT)
Nuclear fuel fired:	1000 MW Pressurised Water Reactor plant.

The basic technical and economical parameters of the candidates are presented in Table 14. All parameters are net parameters, i.e. they are normalised to the net output capacity, since energy balancing is performed at the net plant output.

The public co-generation plants (16% of total system electric capacity, 12% of the total electricity generation in the base year) were aggregated according to fuel type. Their development (mostly replacement of some old coal-fired condensing units by new coal or gas-fired co-generation units) was predetermined, i.e. their plan of development was taken from the Polish Grid Company planning study (ZPR2+) [13]. These co-generation plants were modelled as condensing units as a part of the fixed system.

TABLE 14. Technical and economic parameters of expansion candidates

		COAL	GTCC	GT	IGCC	LIGN	NUCL	PFBC
1. **Technical**								
Output Capacity (Net)	MWe	752	461	163	279	744	940	186
Output Capacity (Min)	MWe	498	269	149	102	391	752	42
Heat Rate – Average Incr.	kcal/kW·h	1878	1634	2407	1847	2046	1786	2033
Heat Rate – Min. Load	kcal/kW·h	2014	1688	2407	1904	2336	2822	2076
2. **Economic**								
Total Construction Costs	US$/kWe	1300	637	220	1455	1314	2121	1408
Fixed O&M Costs	US$/kW/year	9.48	9	5.88	13.44	11.04	34.08	9.24
Variable O&M Costs	mills/kW·h	7.57	0.37	0	2.44	8.79	1.9	1.92
Fuel Costs	USc/Gcal	636.6	1408	2126	636.6	635.1	259.2	636.6
Economic Lifetime	years	35	30	20	35	35	35	35

Small new hydro plants were considered only in a case assuming promoting the use of renewable energy sources. In addition, the following gas-fired CHP plants were also modelled as new distributed generation sources (i.e., independent power producers):

TABLE 15. Technical and economic parameters of small units

Industrial autoproducers:	5 MWe gas turbine plant
District co-generation plants:	3 MWe gas engine plant with heat storage
Individual co-generation plants:	500 kWe gas engine plant

The development projections for small hydro (of a total annual production of 550 GW·h) as well as for the new distributed co-generation sources (i.e., independent power producers (IPP)) have been modelled outside the ELECTRIC module, i.e. in the BALANCE module. In the ELECTRIC module their development is taken into account at the system load level. The special program was developed for modification of the LDC's for all years of the study period (see below).

3.3.1.4.3. Electric sector submodel in the BALANCE module

The electric sector in the BALANCE module is represented by a self-contained sub-module with its own computational procedures. It is embedded in the energy network and is directly linked to other process and decision nodes. It receives electricity demand from a single output link and fuel prices from one or more input links over the simulation period. The module performs the following calculations:

- Develops a discrete approximation of the inverse load duration curve using the Snyder method;
- Computes peak load from the load duration curve and total electricity demand;
- Computes the derated capacity of each of the available electricity generating units;
- Computes the total variable cost (variable O&M plus fuel costs) for each available unit and orders the units on the basis of variable cost or a user defined loading order;
- Loads units into the load duration curve (based on derated capacity) to meet electricity demand, peak load, and reserve margin requirements for the system; and

— Computes average total cost of electricity production and the amounts of fuel consumed by each available generating unit.

To replicate base-year fuel consumption levels from all existing units, it was necessary to split units into two portions: base and peak. Base units are loaded first under the base portion of the LDC, while the peak portions are loaded by the program according to their total variable cost.

In BALANCE the public co-generation plants were modelled according to the fuel type by a multi-output node (electricity driven) and a fictitious generating unit (both input and output carrier is electricity) in the electric sub-module that represented the condensation portion of a co-generation unit. These fictitious plants were modelled as must-run units.

A special algorithm was developed to consider the influence of Independent Power Producers (IPP), driven by heat demand, on the shape of load duration curve and yearly peak load "seen" by system power plants. This algorithm is based on the BALANCE-ELECTRIC calculation loop using program LOAD MODIFICATION, simultaneously with fuel price modification. The load curve modification is done in four steps:

1. Creation of standard load sample – hourly overall load sequence normalised to the maximum annual load
2. Calculation of IPP generation profiles - hourly generation power sequence normalised to the maximum annual load
3. Projections of system generation load profiles as a combination of standard load sample and IPP generation
4. Projection of load duration curves – yearly and quarterly.

The synthesis of standard load sample is based on a synchronisation of hourly load sequences for several past years (1992 to 1997) with the base-year hourly load sequence and calculation of weighted average hourly load. The standard load sample is defined as the average normalised hourly load sequence.

Three types of IPP are considered:

— Industrial CHP plants (autoproducers),
— residential CHP plants with heat storage, and
— individual CHP plants.

The calculation of IPP's generation profiles is based on several assumptions:

— Daily generations of industrial CHP plants are generally flat;
— Daily generations of industrial CHP through the month are constant;
— Monthly modulation of IPP generation does not change over the years; and
— Gas-fired plants (based mostly on diesel engines and heat storage) work as semi-peak plants covering two daily peaks (13 hours during winter period and 11 hours during summer period).

From the normalised hourly sequence (standard load sample) the normalised yearly IPP load profile is subtracted. As a result a new hourly load curve (so called net load) is defined.

Based on the modified (net) hourly load profile a new load duration curves for system generation are obtained (Fig. 33).

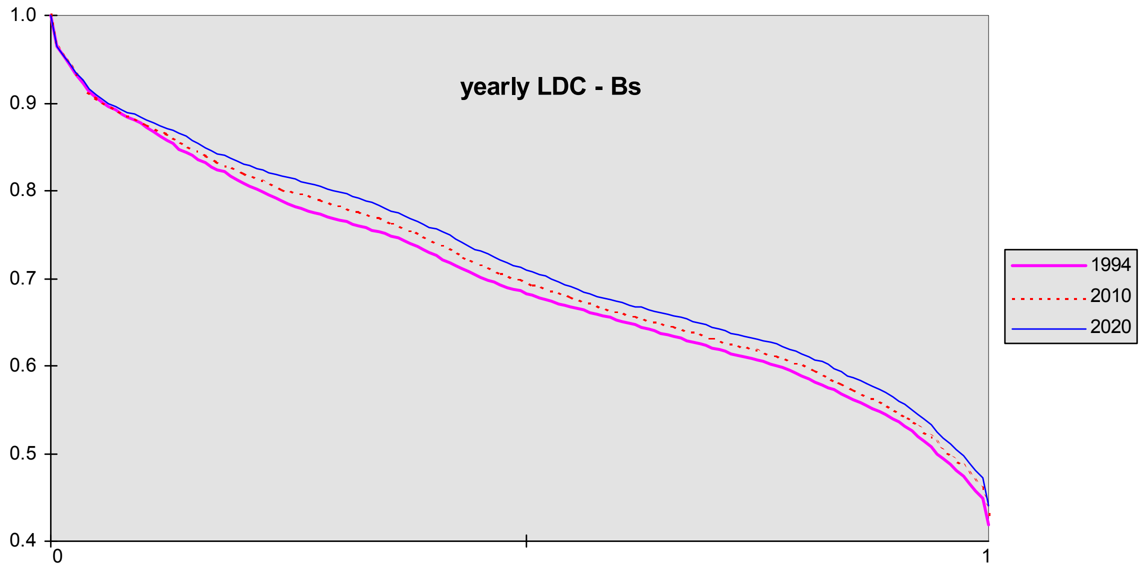


FIG. 33. Yearly modified LDC – base year, 2010 and 2020.

3.3.1.5. Environmental residuals – IMPACTS module

The IMPACTS module of the ENPEP package allows the user to estimate the environmental burdens and resource requirements associated with the energy system that includes both supply side (power plants, refineries, coal-mines) and demand side (industry, transport, residential units) components. Energy system configurations can be designed with the BALANCE module or the ELECTRIC module or by user inputs. Of the various environmental burdens computed by IMPACTS, this analysis mostly concentrated on estimating future air pollution levels.

The approach used in IMPACTS consists of the following steps:

- transfer energy system configuration from BALANCE and/or ELECTRIC
- select environmental coefficients from IMPACTS databases through so-called energy and facility assignments,
- compute uncontrolled environmental residuals,
- apply environmental control requirements,
- distribute energy facilities to geographical regions, and
- compute controlled environmental residuals.

The module works with two integrated extensive databases:

- The Generic Energy Database (GED) is a database of basic energy forms and their carriers that can be used as an input source or output product of energy technologies (extraction, transformation, transportation and final use). The data includes physical, cost and chemical content parameters.

- The Generic Facility Database (GFD) is a database of basic technologies of energy production and processing (supply systems) as well as demand facilities that are direct emission sources. Every generic facility of a type has its own set of data, which contains, among others, cost parameters and environmental data - a set of emission factors for every input energy type.

For many generic facilities, GFD contains data on available control of air pollution emissions. If necessary, the user may introduce new records or change existing records in both databases.

The Generic Facility Database should contain every energy processing technology represented in the case study, particularly facilities which are main sources of air pollution during energy extraction, transformation, transport, distribution and utilisation.

Several new facility types were introduced to GFD to model the specific structure of the Polish energy sector. For instance, a two-input generic facility was created for the gas works, two-output facilities for co-generation power plants with various fuel (input energy) types as well as several "individual" generic facilities for power plants using lignite coal, small-scale coal-burning facilities, local heat plants etc.

3.3.2. General assumptions

3.3.2.1. Energy and fuel availability

1) Hard coal

The assumptions for hard coal extraction were consistent with the Government's coal industry restructuring program that was outlined in the document „The Reform of Polish Hard Coal Industry in the years 1998–2002" [5]. Information contained in this document was used to restrict hard coal mining capacity and its exports to levels shown in Table 16. Additionally, it was assumed that the coal sector curtails production costs, along the assumptions of Government's program.

TABLE 16. Hard Coal Extraction and Export, Mt

	1998	2000	2002	2005	2010	2015	2020
Coal extraction	116	114	110	101	90	85	80
in which: Export	27	23	20	14	10	10	10

It should be emphasised that the assumed coal export may be treated as a reserve margin that results in a secure and stable domestic market and, at the same time, enhances the long-term national energy security.

2) Lignite

Lignite is presently the least expensive primary energy carrier used in Poland for electricity generation. Hence, the level of its future extraction is associated with the planned generation of lignite power plants. „The Prospects of Lignite Industry in Poland" [14] was the basis for modelling the lignite industry. In accordance with this document, it was assumed that the annual lignite production capacity would be in the range of 60 to 70 million tons through the year 2020.

3) Natural gas

At present Poland has the following signed contracts for imported natural gas:

- Long-term contract with Russia — a steady increase from 2.9 billion m^3/year in the year 2000 to about 12.5 billion m^3 in the year 2010,
- Five year contract for Norwegian gas — up to 0.5 billion m^3 annually, starting in the middle of year 2000, with a possible increase subject to future transportation pipeline capabilities,
- Annual contract for German gas — app. 0.5 billion m^3/year with a possible extension over a 15 year period,
- Annual contract with Ukraine for about 1 billion m^3/year.

There are also technical possibilities for modernisation of existing pipelines, allowing an increase of natural gas import from western Europe to about 1.5 billion m^3/year. Beginning in 2010, the total guaranteed gas imports together with the domestic gas extraction capabilities assure a yearly delivery of about 20 billion m^3 (in terms of high-methane gas). In addition, it was assumed that, in the later period, an increase of gas import by several billion m^3/year would be feasible.

4) Crude oil and its derivatives

Domestic crude oil production capacity is relatively low and practically the whole demand is covered by imports. Existing oil loading and transport capabilities significantly exceed the needs of domestic refineries and effectively allow for oil transit services as well as alternative oil supply both from the east European pipeline and sea shipments. Since projected demand for crude oil and its derivatives is below the capacity of existing infrastructure, no constraints on them were modelled.

3.3.2.2. Fuel prices

Fuel price escalation, in particular for imported fuels, varied as a function of different scenarios. Under the Progress-Plus scenario fuel prices were set according to the NEA publication „Projected Costs of Generating Electricity” [15]. The assumed average annual price increase, same during the whole planning period, was: 0.3% for hard coal, 1% for natural gas, crude and fuel oil, and 0.1% for nuclear fuel (Table 17). Corresponding fuel price escalations used in the Survival and Reference scenarios are shown in Table 18. The assumed average annual price growth rates were: hard coal – 1%, crude oil – 1.6%, natural gas and fuel oil – 2.2%, and nuclear fuel – 0.1%.

TABLE 17. Projected fuel prices under the progress-plus scenario

Energy carrier	Unit	1997	2005	2010	2015	2020
Steam coal	USD('97)[a]/t[b]	36.7	37.5	38.1	38.7	39.3
	USD('97)/toe	61.5	62.9	63.8	64.8	65.8
Oil	USD('97)/t	134.6	145.8	153.3	161.1	169.2
	USD('97)/bbl	18.4	19.9	21.0	22.1	23.1
Natural gas[c]	USD('97)/1000 m^3	85.1	93.0	97.7	102.7	108.0
	USD('97)/toe	94.5	103.2	108.6	114.1	120.0

[a]1 USD ('97) = 3.2808 PLN.
[b]Based on questionnaire [16], the assumed calorific value is 25 MJ/kg.
[c]37.7 MJ/m^3 (0.9 toe/1000 m^3).

TABLE 18. Projected fuel prices under survival and reference scenarios[a]

Energy carrier	Unit	1997	2005	2010	2015	2020
Steam coal	USD('97)/t	36.7	40.1	42.5	44.8	47.4
	USD('97)/toe	61.5	67.3	71.0	75.2	79.4
Oil	USD('97)/t	134.6	153.2	165.9	179.8	194.9
	USD('97)/bbl	18.4	21.0	22.8	24.7	26.7
Natural gas	USD('97)/1000m^3	85.1	101.4	113.0	126.1	140.8
	USD('97)/toe	94.5	112.6	125.7	140.2	156.3

[a]The assumptions are as in the previous table, see the footnotes above.

Lignite prices — for individual lignite mines — were obtained from the document of the Lignite Producers Association [16] that was based on responses to a questionnaire about expansion plans of each sub-sector. The weighted average price of lignite in 1997 was 11.3 USD ('97)/t or about 55.0 USD ('97)/toe. The projected average annual price growth rate was 0.1%.

3.3.2.3. Discount rates

The discount rate was assumed to be constant over the entire planning period but was dependent on the macroeconomic scenario as follows: moderate — 10% under the Progress-Plus scenario (more favourable conditions for economic development) and somewhat higher — 12% under the Reference and Survival scenarios.

3.3.3. Primary energy demand projections

Primary energy demand (PED) is directly related to the projected final energy demand. Having accounted for self-consumption in the energy sector, losses in the transformation and transmission/distribution losses, projections of total PED till 2020, broken down by energy carriers, are presented in Table 19 for each of the studied scenarios.

TABLE 19. Primary Energy Demand Projections, Mtoe

Scenario	Energy carrier	1997	2005	2010	2015	2020
SURVIVAL	Hard coal		53.3	53.0	51.9	50.3
	Lignite		13.7	13.8	13.6	13.5
	Oil[a]		20.4	20.2	20.8	21.1
	Natural gas		13.4	16.1	18.8	21.3
	Nuclear		0.0	0.0	0.0	0.0
	Renewable energy[b]		5.3	5.5	5.7	5.9
	TOTAL		106.2	108.6	110.7	112.2
REFERENCE	Hard coal	60.0	52.4	50.8	50.5	49.3
	Lignite	13.5	13.7	13.9	13.6	13.5
	Oil*	18.6	20.2	20.4	21.4	22.3
	Natural gas	9.8	14.6	18.0	20.5	24.0
	Nuclear	0.0	0.0	0.0	0.0	0.0
	Renewable energy[b]	5.5	5.5	6.0	6.5	7.1
	TOTAL	107.3	106.4	109.1	112.4	116.2
PROGRESS-PLUS	Hard coal		49.1	51.0	50.9	49.6
	Lignite		13.7	13.8	13.6	13.5
	Oil*		22.2	23.5	25.3	27.9
	Natural gas		12.9	15.1	18.1	22.6
	Nuclear		0.0	0.0	0.0	0.0
	Renewable energy[b]		5.8	6.3	6.9	7.7
	TOTAL		103.7	109.7	114.7	121.3

[a]Crude oil plus net import of petroleum products excluding feedstock.
[b]Hydro, wind, solar, geothermal, biomass, rape seed oil, ethanol, waste.

Under all scenarios a decline of primary energy demand till the year 2005 is projected. This follows from the assumption of a more efficient use and conservation of energy. Due to the continued increase in the heat price, district heat consumption declines the most rapidly. Certain share in this process, albeit difficult to quantify, will certainly come from the implementation of the “Law on support of thermal energy conservation”. Similarly to final energy demand behaviour, a modest increase of PED is expected in all scenarios after 2005. The total PED growth in the planning period is 4.6%, 8.3% and 13% in the Stagnation, Reference and Progress-Plus scenario, respectively. Corresponding average annual PED growth rates in the same period are 0.2%, 0.36% and 0.55%.

For comparison, the expected developments in total PED are shown in Fig. 34 along with the historical demand development (statistical data for the period 1985-1997). It is quite indicative that projected primary energy requirements in 2020, under all scenarios, are lower than the primary energy consumption in 1988.

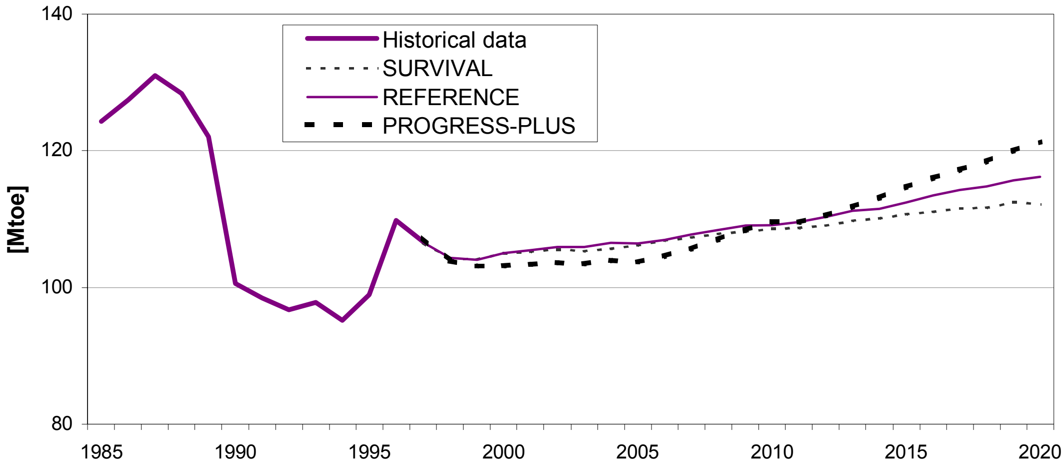


FIG. 34. Historical and projected primary energy demand.

The demand for hard coal gradually diminishes, in accordance with the Government’s programme “The Reform of Hard-Coal Industry in the years 1998-2002”. Independent of scenario, it is assumed that hard coal production capacity is limited to 80 million tons in 2020. Understandably, the decline is highest in the Progress-Plus. In contrast, it is the lowest in the Survival scenario, since in this case Polish economy will not be able to generate conditions for a sustained development and an economy structure based on raw material will persist. The largest drop in coal use occurs in the years 1998-2005, mainly due to reduced heat demand and a switch to natural gas and fuel oil for heating. A smaller overall decrease is observed in later years due to an increased use in electricity.

Independent of scenario, a significant increase in natural gas consumption is noticeable, especially in the power sector (small and medium size co-generation sources). In other sectors that increase is smaller. The competitiveness of natural gas with respect to coal is based on higher conversion efficiencies and its relatively low impact on the environment (in contrast to coal, no expensive SO_2 and particulate reduction equipment is required in gas fired facilities).

Requirements for crude oil and imported petroleum products are also increasing, mainly in the transport sector. This is consistent with the projected increase of transport services. There is a relatively larger increase in passenger transport in scenarios with higher growth rates, and inversely, a larger increase of freight transport in the Survival scenario. A small decrease in the supply of oil products in the period 2005-2010 under the Survival scenario is caused by a partial switch from heating fuel oil to natural gas in the industrial and residential sectors and as well as a small increase in fuel demand in the transport sector.

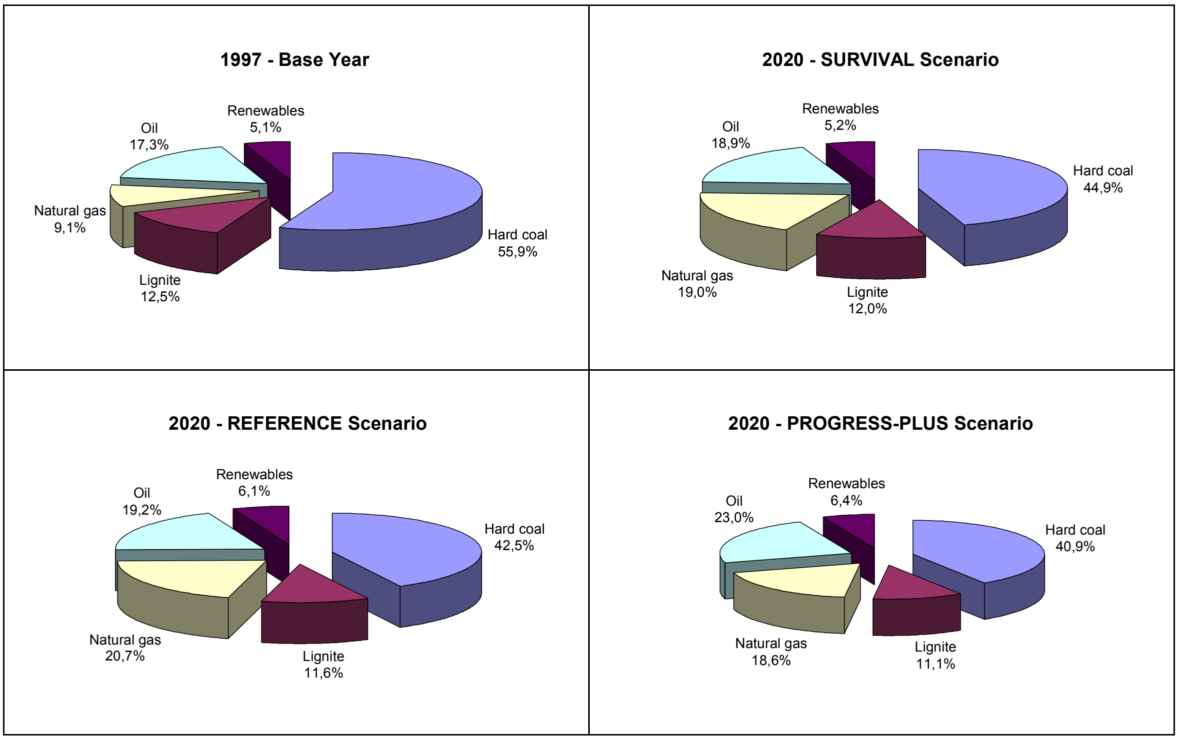


FIG. 35. Structure of primary energy demand.

Figure 35 presents the primary energy mix at the beginning and the end of study period. Under projected hard coal use, its share in total demand is still the highest but it decreases strongly, from about 56% in 1997 to about 45% in Survival, 42.5% in Reference and below 41% in Progress-Plus scenario. Due to an overall demand increase, the share of lignite also diminishes, although the level of its production stays virtually unchanged. The share of domestic coal in primary energy demand (much higher than in the EU) remains certainly high, thereby curtailing the dependence on fuel imports and improving energy self-sufficiency. However, it also requires substantial investments in environmental protection.

In all scenarios, the share of natural gas will continue to increase rapidly. It more than doubles in 2020 compared to 1997. Of course this means large gas imports and higher dependence on imports. On the other hand, the resulting larger fuel diversification has a positive impact on supply security. The increase in gas imports would require new investments in the transport infrastructure, a fact that was taken into account in the analysis.

A modest increase in the share of liquid fuels share is projected. This is of importance since crude oil comes almost completely from imports.

Due to a limited technical potential and low cost-effectiveness, the current low share of renewable energy sources will not change significantly. It will remain below 6.5%. Large additional policy efforts, including special promotional measures, would have to be taken, if the share of renewables in the overall energy mix is to be increased.

3.3.4. Projection of fuel input for electricity and heat cogeneration

Table 20 presents the expected development in primary energy consumption, by energy carriers, for electricity and combined heat and power (CHP) generation. Independent of scenario, hard coal remains the main energy carrier for power and heat co-generation. Its use moderately but steadily increases over the study period. The maximum possible use of lignite, the least expensive carrier, is assumed in all scenarios. Natural gas rapidly increases in importance, constantly increasing its share from virtually zero in 1997 to about 11% in 2020 under the Survival scenario, to 14% in the Reference scenario, and to 15.5% in the Progress-Plus scenario. The role of renewable energy also increases, but to a much lower extent, since its maximum share in 2020, projected under the Progress-Plus scenario, stays below 6% of the overall energy demand. Finally, no nuclear power use is forecasted over the studied planning period in any scenario.

TABLE 20. Fuel Consumption in Electric Power and Co-Generation Plants, Mtoe

Scenario	Energy carrier	1997	2005	2010	2015	2020
Electricity generation, TW·h			*161.8*	*175.9*	*187.7*	*201.9*
Heat co-generation, Mtoe[a]			*6.8*	*7.6*	*8.0*	*8.3*
SURVIVAL	Hard coal		27.5	29.1	29.5	29.0
	Lignite		13.3	13.4	13.2	13.1
	Natural gas		1.1	2.1	3.6	5.4
	Oil		0.1	0.1	0.1	0.1
	Renewable energy[b]		0.9	1.2	1.5	1.8
	Nuclear		0.0	0.0	0.0	0.0
	Total		42.9	46.0	47.9	49.4
Electricity generation, TW·h		*142.7*	*167.6*	*186.9*	*204.4*	*233.2*
Heat co-generation, Mtoe[a]		*8.8*	*6.7*	*7.5*	*7.9*	*8.2*
REFERENCE	Hard coal	24.0	26.9	27.7	28.9	28.8
	Lignite	13.2	13.4	13.5	13.3	13.1
	Natural gas	0.6	1.7	3.4	4.7	7.5
	Oil	0.3	0.1	0.1	0.1	0.1
	Renewable energy[b]	0.4	1.2	1.8	2.3	3.1
	Nuclear	0.0	0.0	0.0	0.0	0.0
	Total	38.4	43.3	46.4	49.3	52.6
Electricity generation, TW·h			*161.5*	*184.4*	*204.8*	*236.4*
Heat co-generation, Mtoe[a]			*6.7*	*7.6*	*8.1*	*8.5*
PROGRESS-PLUS	Hard coal		23.6	26.6	27.5	26.9
	Lignite		13.3	13.5	13.3	13.1
	Natural gas		2.7	3.4	4.9	8.0
	Oil		0.3	0.3	0.3	0.3
	Renewable energy[b]		0.9	1.4	2.1	3.0
	Nuclear		0.0	0.0	0.0	0.0
	Total		40.8	45.2	48.0	51.3

[a]Total heat co-generation [13].
[b]Hydro, wind, biomass and waste.

The projected electric generation capacities (old and predicted new public power (PP) and combined heat and power (CHP) plants; industrial, district and individual CHP plants) are shown in Table 21. Additionally, a comparison between installed capacity and load demand in the years 1997–2020 is presented in Figs 36–38.

New public generation plants appear only after 2013. Large-scale combined heat and power for district heating and industrial applications, as well as small CHP applications have a large potential, which can be exploited in the long-term. Co-generation can contribute significantly to the reduction of environmental emissions, and increase in energy efficiency.

TABLE 21. Projections of electricity generation capacities, MWe

Scenario		1997	2005	2010	2015	2020
SURVIVAL	*Load demand*		*26492*	*28597*	*30822*	*33497*
	Public Power and CHP Plants		32512	32552	32511	29761
	Other CHP Plants		4106	5875	7188	7722
	New public plants[a]		0	0	810	6135
	Available capacity		36618	38427	40509	43618
REFERENCE	*Load demand*	*24337*	*26700*	*29327*	*32494*	*36738*
	Public Power and CHP Plants	29486	32512	32552	32511	29761
	Other CHP Plants	2592	4607	6532	8325	9031
	New public plants[a]	0	0	0	2100	9035
	Available capacity	32078	37119	39084	42936	47827
PROGRESS-PLUS	*Load demand*		*25729*	*28943*	*32558*	*37247*
	Public Power and CHP Plants		32512	32552	32511	29761
	Other CHP Plants		3257	6019	8408	9693
	New public plants[a]		0	0	2100	9035
	Available capacity		35769	38571	43019	48489

[a]According to assumptions in Section 3.3.5.

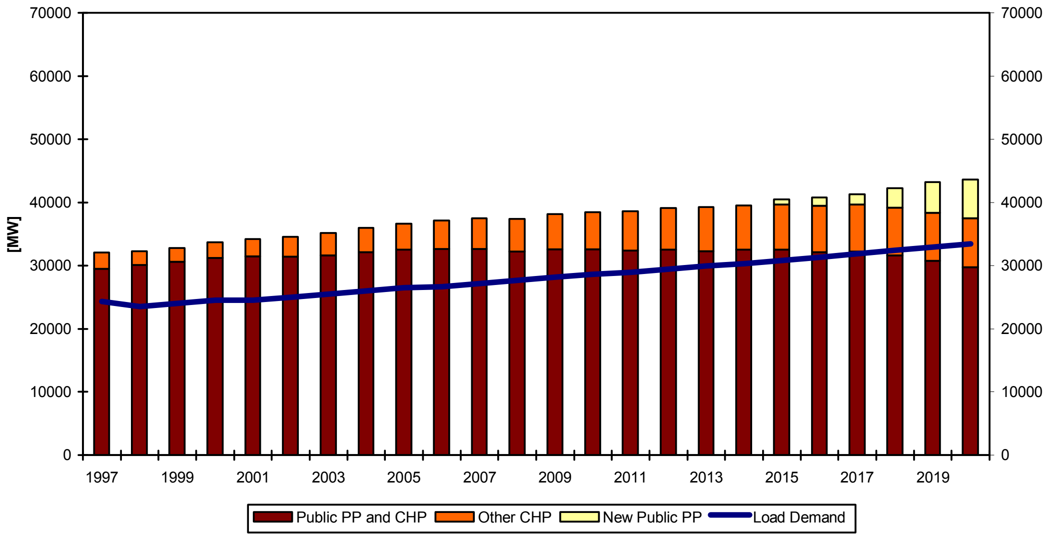


FIG. 36. System load demand and available capacities – Survival scenario.

The total share of CHP in 2020 (in terms of share of electricity production) is estimated at about 35% in Survival and above 40% in Reference and Progress-Plus Scenarios. This is more than a two-fold increase in comparison to the 1997 level. A particularly large increase of distributed (including renewables) generation systems can be expected (Fig. 37), among which small gas-fired co-generation plants prevail (30–40%). However, in the short-term small CHP faces several market barriers that must be overcome by targeted promotion policy. The share of industrial CHP plants in electricity generation is projected to decrease only slightly, in spite of a more significant capacity decrease, since many of these plants are expected to switch from coal to gas, thus increasing their capacity factors.

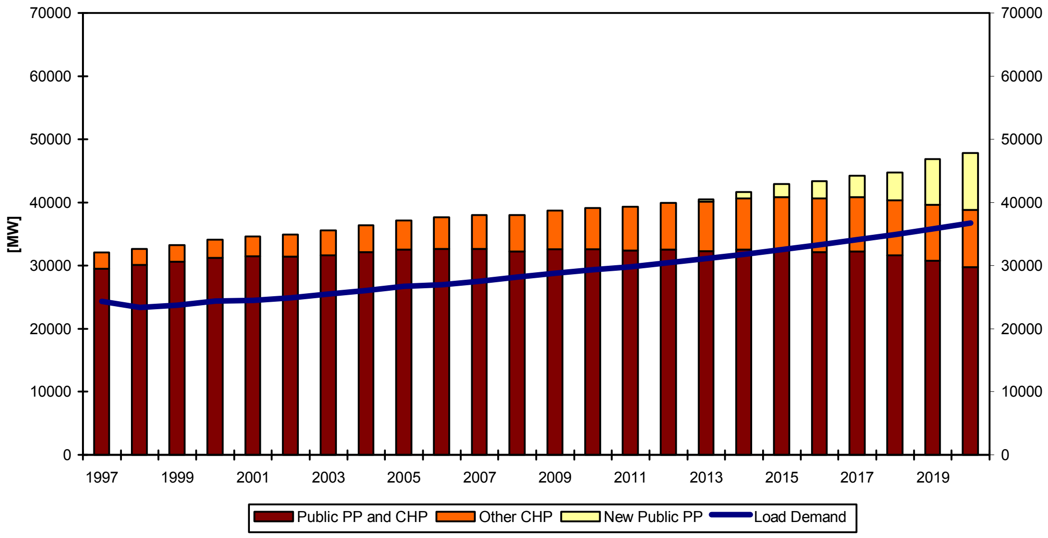


FIG. 37a. System load demand and available capacities – Reference scenario.

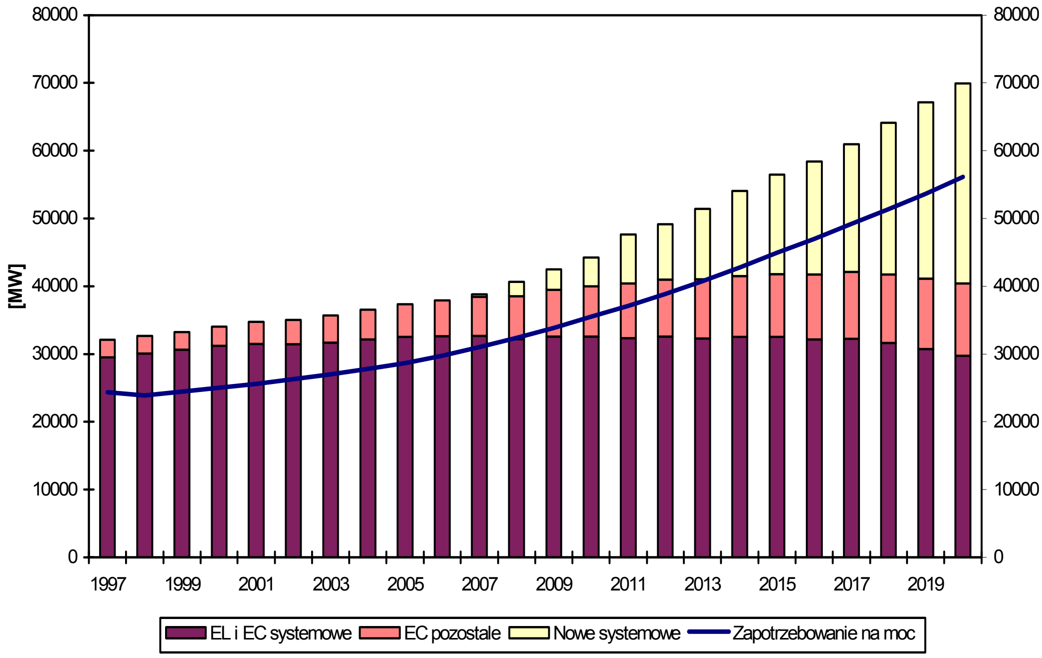


FIG. 37b. System load demand and available capacities – Progress-Plus scenario.

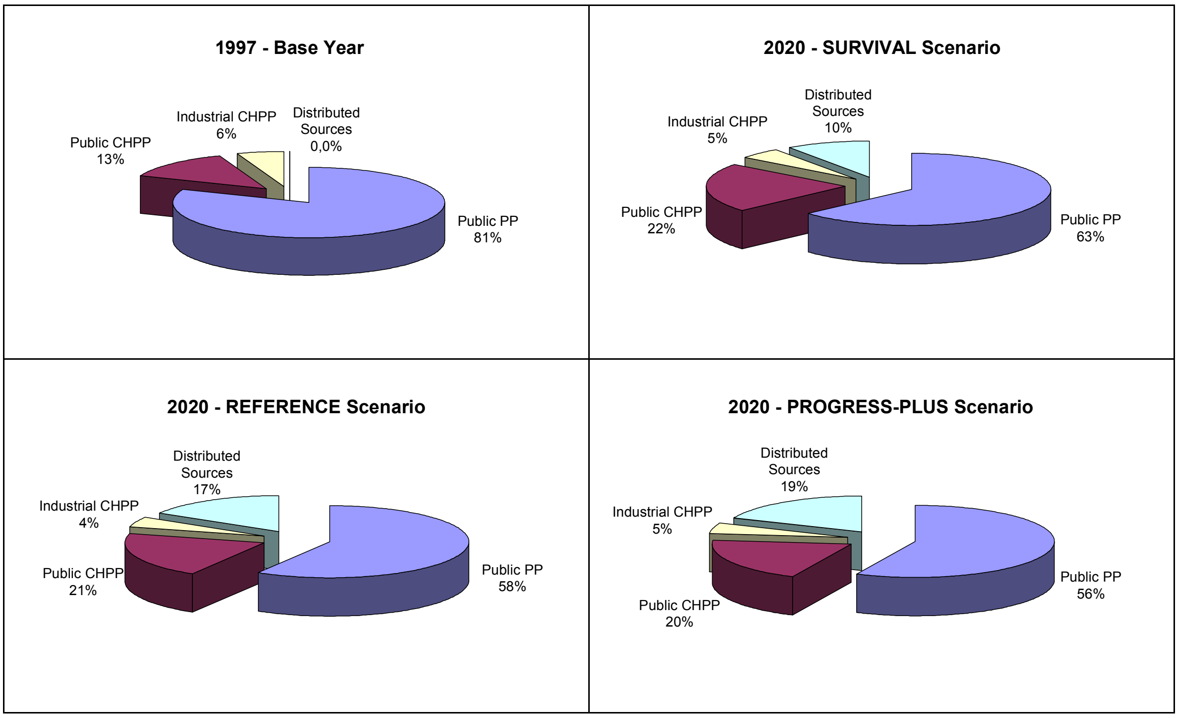


FIG. 38. Structure of electric energy generation by source.

3.3.5. Analysis of the electricity generation mix

Until the end of the year 2020, there will be a cumulated demand for new capacities of 11.5 GWe (Survival) to about 16 GWe (Reference and Progress-Plus). The projected new power plant capacities in the analysed time period, by plant type, energy carrier and technology are presented in Table 22 (aggregated in 5-year intervals) and in Figs 39–41.

The expansion plan for the public CHP plants was pre-determined, i.e. taken from the Polish Grid Company's power system expansion study (ZPR2+) [13] and kept fixed in all scenarios. These new co-generation units are mostly replacements of the old and obsolete coal-fired power plants. The assumed technology is generally hard coal fluidised bed combustion and pulverised coal with FGD, although in some cases substitution of coal for gas is planned.

The projections for industrial and distributed co-generation come from the ENPEP analysis. While all new industrial co-generation units are gas-fired turbines, the distributed co-generation includes not only natural gas-fired district heating and individually owned co-generation plants (assumed technology is gas engines) but also the renewable sources (small hydro plants, wind turbines and biomass co-generation plants). The development of renewable sources reflects the increasing government's support and promotional policy for these sources, while the gas-fired small co-generation growth is additionally driven by environmental requirements, i.e. replacement of old coal-fired district heating plants by gas fired co-generation, avoiding the need for installation of the expensive equipment for pollutant emissions reduction. As it is easily seen the structure of electricity generation will be greatly affected by the substantial increase of distributed generation sources.

TABLE 22. Projected new generation capacity, MW_e net

	SURVIVAL Scenario				
	1998–2005	2006–2010	2011–2015	2016–2020	Total
Distributed CHPP	1794	1699	1282	466	5242
Industrial CHPP – Gas fired	160	72	31	68	330
Public CHPP – Coal and gas fired	2438	606	994	470	4508
Public PP	0	0	810	5325	6135
Lignite-fired	*0*	*0*	*0*	*0*	*0*
Gas turbine	*0*	*0*	*330*	*1485*	*1815*
GTCC	*0*	*0*	*480*	*3840*	*4320*
	REFERENCE Scenario				
	1998–2005	2006–2010	2011–2015	2016–2020	Total
Distributed CHPP	1811	1860	1735	590	5996
Industrial CHPP – Gas fired	195	65	58	117	434
Public CHPP – Coal and gas fired	2438	606	994	470	4508
Public PP	0	0	2100	6935	9035
Lignite-fired	*0*	*0*	*0*	*3200*	*3200*
Gas turbine	*0*	*0*	*660*	*1815*	*2475*
GTCC	*0*	*0*	*1440*	*1920*	*3360*
	PROGRESS-PLUS Scenario				
	1998–2005	2006–2010	2011–2015	2016–2020	Total
Distributed CHPP	992	2750	2238	1059	7039
Industrial CHPP – Gas fired	313	40	151	225	730
Public CHPP – Coal and gas fired	2438	606	994	470	4508
Public PP	0	0	2100	6935	9035
Lignite-fired	*0*	*0*	*0*	*3200*	*3200*
Gas turbine	*0*	*0*	*660*	*1815*	*2475*
GTCC	*0*	*0*	*1440*	*1920*	*3360*

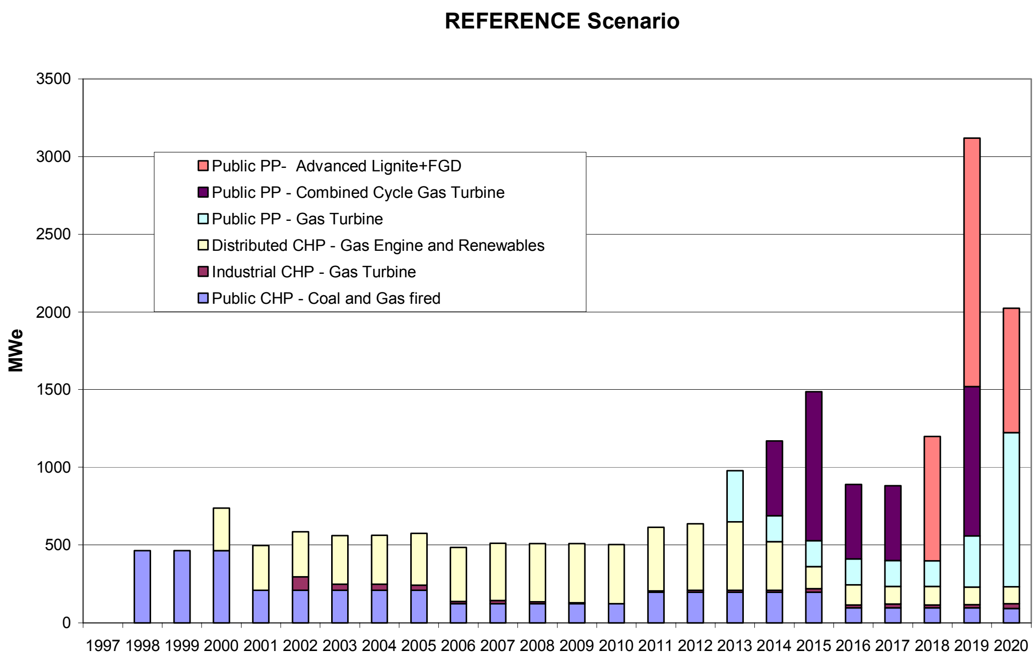


FIG. 39. New generating capacities mix – Reference scenario.

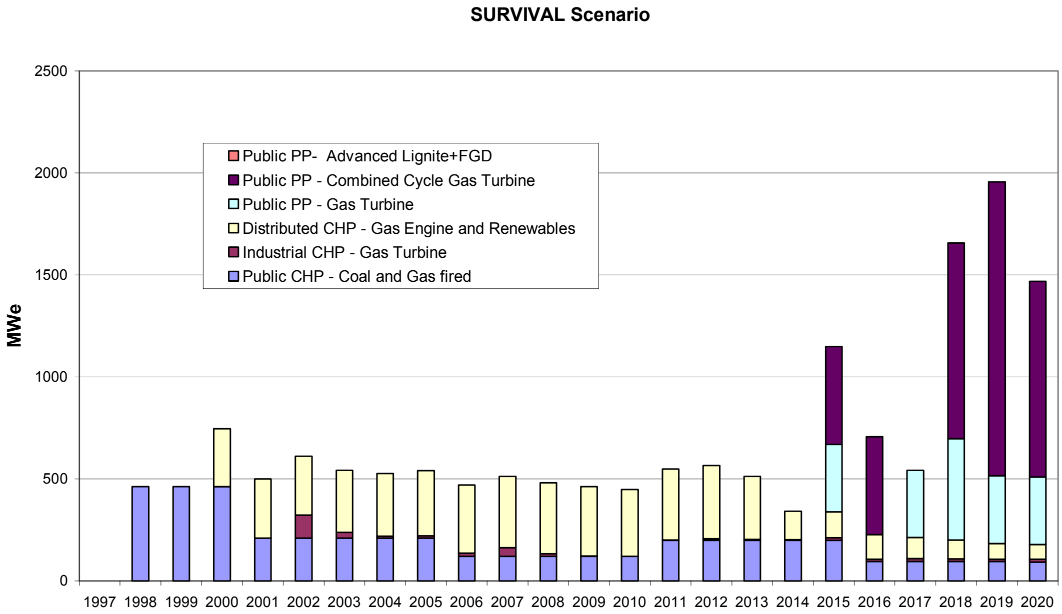


FIG. 40. New generating capacities mix – Survival scenario.

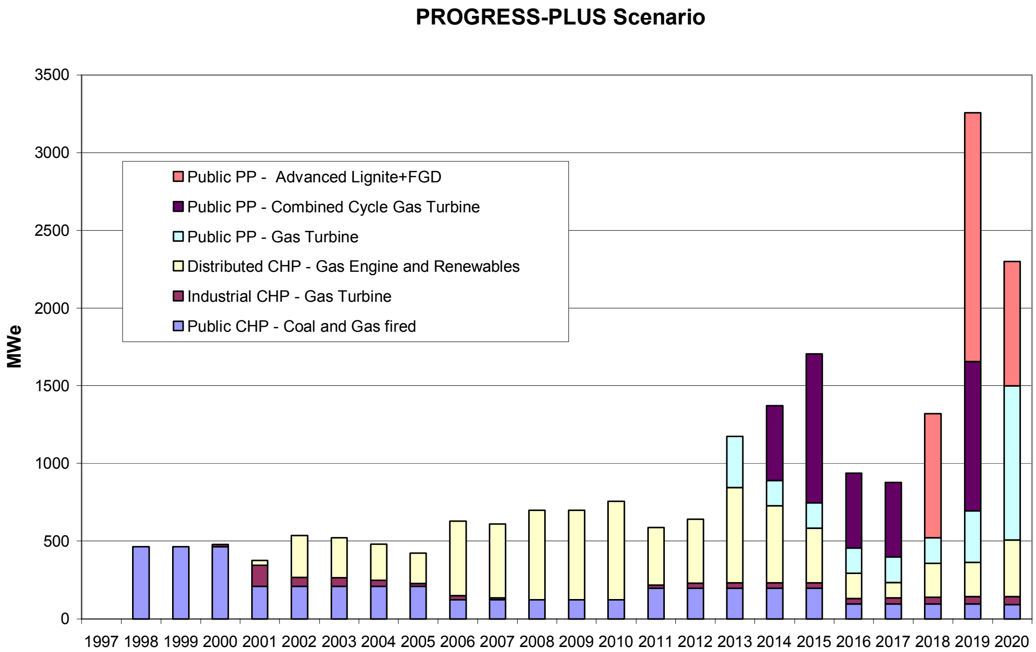


FIG. 41. New generating capacities mix – Progress-Plus scenario.

The WASP projected optimal expansion plan for the public power generation shows that planned modernisation and upgrading of the existing plants will be able to reliably meet demands for the next 10–15 years. It is noticeable that new generating capacities include mostly combined cycle gas turbine (CCGT) and peaking gas turbine plants, and no nuclear power plants. The appearance of new lignite-fired units by the end of the study period is due to successive replacement of the shutdown units in the biggest Polish power plant Bełchatów.

There are couple of reasons for low competitiveness of nuclear power. A simplified comparison of candidates for new generation by the screening curve method (Figs 42–43 illustrating production cost of the alternative power generation technologies) shows that high investment costs render nuclear power non-competitive[5]. The curve for the year 2000, reflecting the situation with the present gas prices, shows that low capital cost combined cycle power plants using natural gas remain the most favourable solution. Even at extremely high utilisation rates the PWR nuclear generating technology option is non-competitive. In the case of increasing natural gas prices, which is assumed in our forecasts (Screening curve for 2020 assumes a 2.2% annual gas price increase and virtually unchanged nuclear fuel price), the situation is somewhat different. New condensing power plants using coal are the most economical option to satisfy the electricity demand in the base load. Nuclear option is more economical than gas option at the utilisation rates above 70%. For peaking load simple gas turbines are the preferred choice since at lower operating levels the role of fuel price in total operating cost becomes less significant.

Nevertheless the optimal expansion plan must take into account additional constraints, such as the shape of the load curve, planned retirements, co-generation, etc. The WASP analysis shows that new capacities will satisfy mainly middle and peaking load, and CCGT and peaking gas turbines still remain, from the economic point of view, the best solution.

It should be emphasised that, one of the decisive reasons for the introduction of nuclear power — mitigation of air pollution and greenhouse gases emissions in order to meet the international obligations — was not a critical factor in the analysis, since under all scenarios, the compliance with environmental constraints was not a critical factor.

However, it should be emphasised that beyond 2020 the prospects for nuclear energy (or some new technology) might be brighter, taking into account that domestic coal production will be limited and the import of natural gas is constrained by the existing and presently planned pipeline infrastructure as well as for energy security reasons.

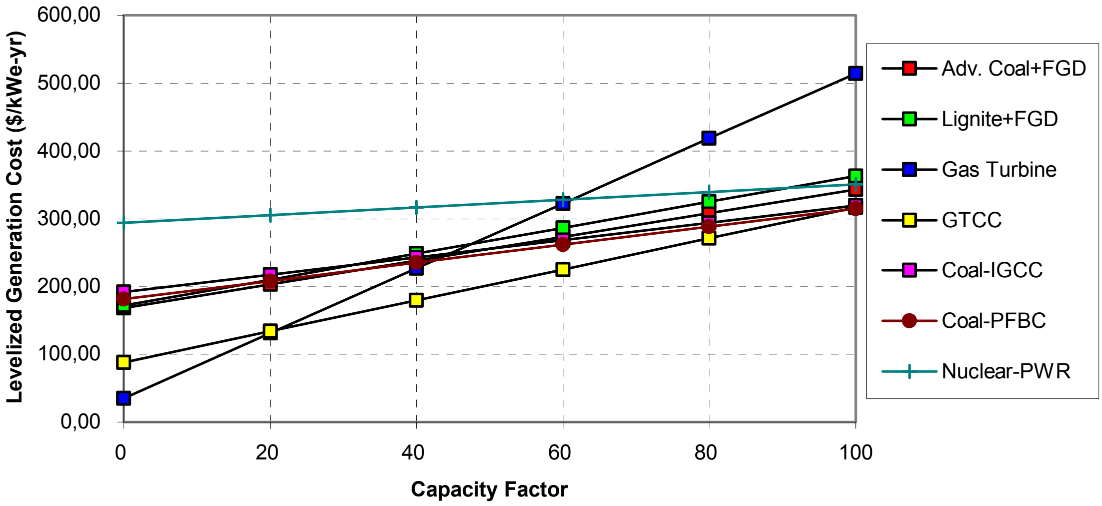


FIG. 42. Screening curves comparison of candidates for 2000.

[5] See Table 14 for technical and economic assumptions.

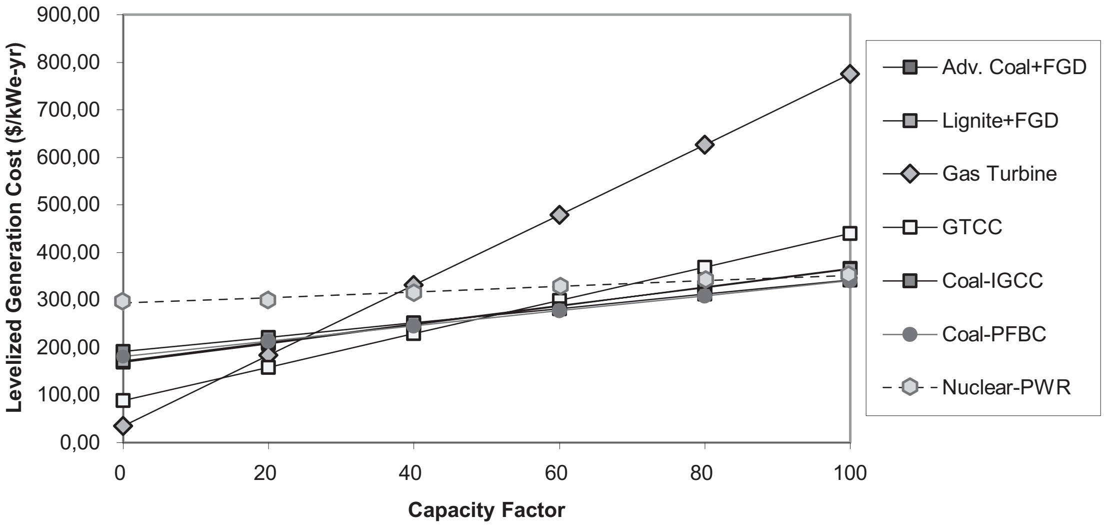


FIG. 43. Screening curves comparison of candidates for 2020.

3.3.6. Energy supply security indices

The two main indicators used to describe the energy supply security of a country are:

- energy self-sufficiency defined as domestic production/TPES ratio,
- diversification of primary energy supply.

In contrast to an open economy, where energy supply diversity is of more importance, in an autarchic economy increased self-sufficiency (in consequence lower import dependency) is preferred.

Figure 44 shows that currently Poland has a high index of energy self-sufficiency. A steady decline of this value is projected over the next two decades to about 60% in the year 2020. The largest contributions to increased imports are due to large increases in gas imports, supported by continuing oil imports. Nevertheless, the self-sufficiency index for Poland is projected to be above the present average value for the EU countries, and much higher than, for instance, the energy security index for Germany and France. Liberalisation of international energy markets can stimulate a further decline in this index.

As an indicator of fuel supply diversity one can use the so-called Stirling's index. It is higher if more energy carriers form the energy mix as well as if the share of different energy carriers is more uniform. The Stirling formula is as follows [15]:

$$H = -\sum_i p_i \times \ln(p_i)$$

where p_i is the share of energy carrier i in the portfolio of energy consumption.

By differentiating lignite and hard coal as two independent energy carriers, the primary energy diversity index for Poland is similar to the one in the neighbouring countries (Table 23).

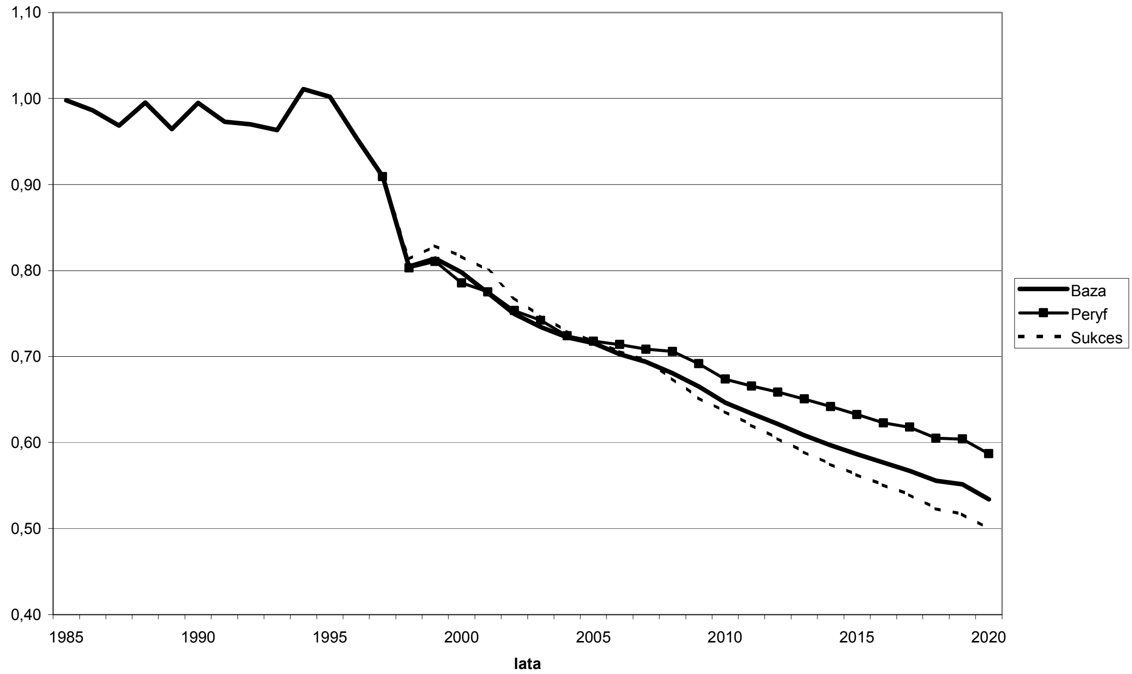


FIG. 44. Historical and projected energy self-sufficiency indices.

TABLE 23. Structure of primary energy sources (in %) and Stirling indices for some EU countries (1996) [17] and Poland

	Hard Coal	Lignite	Crude Oil	Natural Gas	Nuclear	Other	Stirling Index
France	6,1	0,2	35,0	12,6	39,8	6,9	**1,36**
United Kingdom	19,5	0,0	36,7	32,5	10,6	0,7	**1,32**
Germany	14,7	11,0	39,7	21,0	11,9	1,7	**1,54**
Denmark	36,7	0,0	41,6	15,2	0,0	6,5	**1,20**
Italy	7,1	0,0	58,9	29,2	0,0	4,7	**1,00**
Poland							
1997	55,9	12,6	17,3	9,1	0,0	5,0	**1,26**
2020-Survival	44,8	12,0	18,8	19,0	0,0	5,2	**1,40**
2020-Reference	42,4	11,6	19,2	20,6	0,0	6,1	**1,43**
2020-Progress	40,9	11,1	23,0	18,6	0,0	6,4	**1,44**

The results of the analysis show that, the value of Stirling's fuel diversity index for Poland would grow to above 1.4 by 2020. The smallest increase, of course, is predicted in the Survival scenario, reflecting lower imports than in the two other scenarios. Predicted gas imports, from the point of view of fuel diversification, are beneficial to security of supply. On the other hand, large gas imports lower the security of supply where import dependency is concerned. For this reason, diversification of gas suppliers will be of great importance to the country's future energy security.

3.3.7. Energy prices for end-users

The average annual prices of energy carriers include costs for the whole energy chain – from fuel extraction to energy consumption by the end-user. Projected final energy costs are an important indicator of competitiveness of energy sector activities. Tables 24–26 summarise the projected prices of electricity, natural gas and district heat for households, under all scenarios.

TABLE 24. Projected average annual prices of electricity for households

Scenario		1997	2005	2010	2015	2020
SURVIVAL	US$/MW·h	50.6	65.5	68.2	80.3	91.6
	price growth	100	129	135	159	181
REFERENCE	US$/MW·h	50.6	71.5	79.3	89.7	98.3
	price growth	100	141	157	177	194
PROGRESS-PLUS	US$/MW·h	50.6	75.9	79.3	90.5	99.4
	price growth	100	150	157	179	196

TABLE 25. Projected average annual prices of natural gas for households

Scenario		1997	2005	2010	2015	2020
SURVIVAL	US$/1000 m^3	178	199.1	210.4	221.1	237.2
	price growth	100	112	118	124	133
REFERENCE	US$/1000 m^3	178	199.9	211.4	221.8	238.4
	price growth	100	112	119	125	134
PROGRESS-PLUS	US$/1000 m^3	178	187.8	195.2	203.6	211.7
	price growth	100	105	110	114	119

TABLE 26. Projected average annual prices of district heat

Scenario		1997	2005	2010	2015	2020
SURVIVAL	US$/GJ	7.8	7.8	7.8	9.8	11.1
	price growth	100	100	100	125	143
REFERENCE	US$/GJ	7.8	8.0	9.4	10.6	11.5
	price growth	100	103	120	136	147
PROGRESS-PLUS	US$/GJ	7.8	7.1	7.1	7.0	7.0
	price growth	100	91	91	90	90

An almost two-fold increase in electricity prices is expected by the year 2020. The dynamics of the increase is the smallest in the Survival scenario (lowest level of new generating capacity), particularly in the first half of the planning period. A moderate rise of natural gas prices is predicted under all scenarios, the lowest increase however (only about 20% over whole study period) is in the Progress-Plus Scenario. Finally, a significant increase (about 45%) in district heat prices is projected in both the Survival and Reference scenarios. In contrast, the Progress-Plus scenario projects a slow but steady decrease of central heat price. This is a consequence of assumed lower fuel price growth rates as well as increased co generation of heat and power.

3.4. Basic indicators of energy use

Projected results for the future energy supplies and end use can be compared with their 1988 values — the last year of centrally planned economy — and with 1997 (base year) values. As shown in Table 27 for the energy productivity indicators with respect to primary energy demand (TPES), gross electrical energy demand (GED), final energy demand (FED) and final electricity consumption (FEC). As it can be seen, positive changes take place under all scenarios. A two to four-fold increase in total primary and final energy productivity occurs, depending on scenario. The predicted growth of electrical energy productivity is however much smaller (two-fold at the best).

TABLE 27. Projected energy productivity growth (1988 = 100)

	Historical Data		Predictions			Scenario
	1988	1997	2000	2010	2020	
Primary energy productivity (GDP/TPES)	100	135	165	176	216	SURVIVAL
			198	232	307	REFERENCE
			210	268	406	PROGRESS-PLUS
Gross electricity productivity (GDP/GED)	100	118	124	124	138	SURVIVAL
			144	155	175	REFERENCE
			153	182	237	PROGRESS-PLUS
Final energy productivity (GDP/FED)	100	137	176	188	228	SURVIVAL
			211	245	322	REFERENCE
			222	284	418	PROGRESS-PLUS
Final electricity productivity (GDP/FEC)	100	123	127	125	129	SURVIVAL
			147	152	159	REFERENCE
			160	181	216	PROGRESS-PLUS

In Fig. 45 some additional indicators were presented. As shown, the GDP per capita index reached the value from the year 1988 only in 1996. A steady rise of its value is predicted in the whole study period, and by the year 2020 it becomes two to four times greater than in 1988. The projected primary energy demand, on the other hand, surpasses its base-year value only in the Progress-Plus scenario. In contrast, electricity demand clearly shows a rising tendency under all scenarios.

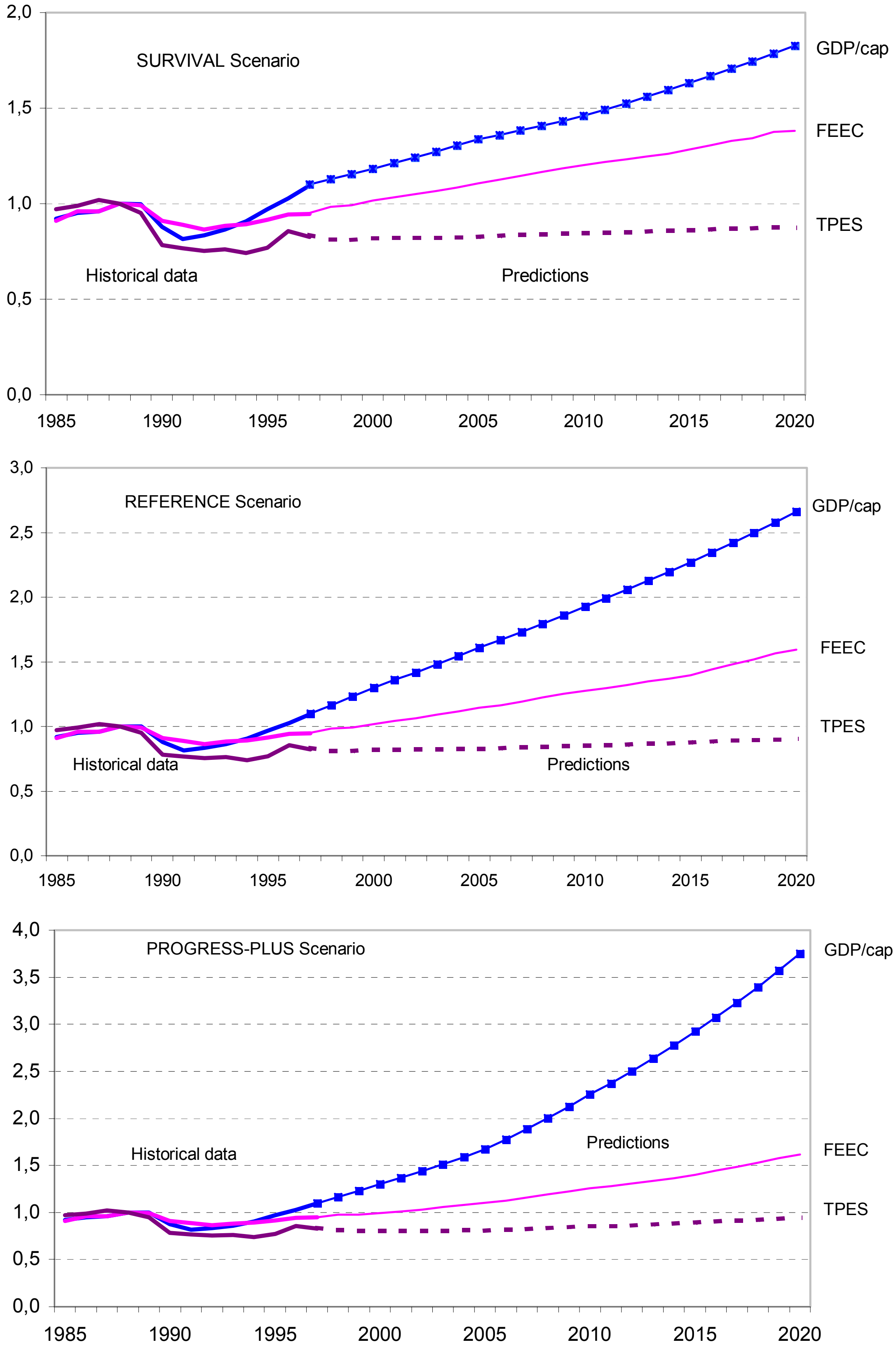
A further illustration of the results is provided in Table 28 that presents a comparison of projected energy indices for Poland and the EU for the year 2020. Independent of scenario, all energy productivity indicators for Poland remain below 50% of the corresponding average values for EU countries. The corresponding differences in the energy and electricity supply per capita in 2020 are about 30%.

3.5. Environmental considerations

For this study emissions of only airborne pollutants were analysed. It was assumed that mitigation measures for reducing surface water pollution by waste saline water from coal mines would be included in the Government's programme for the restructuring of the hard coal industry as well as in the new Geology and Mining Law. Similarly, it was assumed that the government would initialise activities leading to safer underground storage and/or better utilisation of solid waste from coal mines and power plants (i.e., for construction materials and mineral fertilisers).

3.5.1. Methodology for emission estimates

The emissions of the major airborne pollutants (particulate matter, sulphur dioxide – SO_2, nitrate oxides – NO_x and carbon dioxide – CO_2) were computed using the IMPACTS module of ENPEP. IMPACTS computes emissions based on information provided by energy and economic scenarios as exogenous input from the BALANCE module and on emission factors, derived from national reports, EMEP/CORINAIR emission inventory [21], IPCC inventory [22], EMA database and contacts with national experts. Emission estimates are performed on a disaggregated level, which is determined by the available details of the



FEEC - Final electric energy consumption
TPES - Total primary energy supply

FIG. 45. Macroeconomic and energy use indices (1988 = 1).

TABLE 28. Comparison of projected energy indices for Poland and the European Union (conventional wisdom scenario)

Indicator	Units	1997 Poland	Forecast 2020			
			Poland			EU
			SURVIVAL	REFERENCE	PROGRESS	
GDP per Capita	USD'95/cap	3700	5940	8740	12570	40420
Primary Energy Consumption (TPES) per Capita	kgoe/cap	2780	2780	2880	3110	4270
Gross Electricity Consumption (EE) per Capita	kW·h/cap	3630	5010	5780	6060	8330
Final Energy Consumption (TFC) per Capita	kgoe/cap	1860	1790	1870	2070	2890
Final Electricity Consumption (TFCE) per Capita	kW·h/cap	2450	3740	4480	4740	7100
Productivity (GDP/TPES)	USD'95/kgoe	1.33	2.14	3.03	4.04	9.46
Productivity (GDP/EE)	USD'95/kW·h	1.02	1.19	1.51	2.07	4.85
Productivity (GDP/TFC)	USD'95/kgoe	1.99	3.31	4.66	6.06	13.97
Productivity (GDP/TFCE)	USD'95/kW·h	1.51	1.59	1.95	2.65	5.70
τ_{GDP}	%	-	2.30	4.00	5.50	2.16
τ_{TPES}	%	-	0.20	0.30	0.53	0.58
τ_{EE}	%	-	1.60	2.22	2.29	1.18
τ_{TFC}	%	-	0.02	0.20	0.51	0.39
τ_{TFCE}	%	-	2.04	2.85	2.95	1.24

τ_x — average annual growth

projections of future fuel production, conversion and consumption. IMPACTS calculates present and future emissions as a product of activity level (e.g., fuel consumption of a facility or process obtained from BALANCE module), an emission factor (appropriate for the technology and fuel used) and removal efficiency of the control technology or any other measure/activity leading to a reduction of the unit emission rate as shown in the following equation:

$$E(t) = \sum_i A_i(t) * WE_i * (1 - \eta_i(t))$$

where:

- $E(t)$ - pollutant emission in year t,
- $A_i(t)$ - level of activity i in year t
- WE_i - emission factor per unit of activity
- $\eta_i(t)$ - pollutant removal efficiency in year t

Any change in emission factors over time (e.g., caused by a changed sulphur content of fuel) is interpreted as an emission control measure and reflected via a modified factor η.

3.5.2. Main input assumptions

The analysis used a detailed inventory of production and abatement technologies. It also used information concerning existing environmental legislation. Additional analysis was performed on new proposals for emission control regulations. These proposals take into account the latest national legislation, relevant directives of the European Union and obligatory clauses regarding emission standards from the signed international conventions on air protection (i.e., the Second Sulphur Protocol of the Geneva Convention on Long-Range Transboundary Air Pollution – LRTAP) as well as present and planned technical and ecological undertakings for emission controls in various economy sectors. The values and timings of implementation of pollution control measures in different sources and processes were set up. Main input assumptions and guidelines used in the energy forecasts are summarised below:

— National as well as sectoral emission estimates for the base year (1997) should be in good agreement with the official statistical data IOŚ/GUS (Emission inventory of the Institute of Environmental Protection/ Main Statistical Office) [18].

— For public power and co-generation plants: (1) implementation of environmental protection programs related to reduction of particulate matter and NO_x emissions, and (2) completion of the "Program of abatement of SO_2 emissions in the electric utility sector" (a part of technical modernisation plans), in accordance with the long-term power and energy purchase contracts made by individual utilities with the Polish Grid Company (PSE SA) in the years 1993-1998. The level of emission controls for these facilities were taken from an assessment of future compliance of existing public and industrial power and co-generation plants to new emission standards for particulates, SO_2 and NO_x [19]. The new emission standards, introduced on Sept 8, 1998 [20], ensure compliance with Poland's international treaties and protocols (i.e. Second Sulphur Protocol of LRTAP) as well as harmonisation with EU legislation. Poland's requirements are identical or in some cases even more stringent then existing EU standards - Dir. 88/609/EEC, concerning the Large Combustion Plants -LCP[5].

— For all other facilities — public power and co-generation plants presently not included in the technical/ecological modernisation programs, industrial co-generation and heating plants as well as district heating plants — a full compliance with the new Polish emission standards, starting, as required, from the year 2006. Under existing modernisation plans, about half of installed power in public co-generation plants would not, at least for some pollutants, fulfil new emission standards in the year 2006 [19]. Nevertheless, it was assumed that these utilities would appropriately revise their plans and undertake appropriate mitigation measures by 2006 in order to comply with the new legislation (these facilities can do it with a limited use of expensive technologies). The same assumption applies to industrial co-generation and district heating plants, although the data about their

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[5] It should be emphasized that there is a proposition for a new UE directive concerning the airborne emissions from LCP, which might significantly strengthen emission requirements for existing plants starting from 2007 (comparable to present emission standards for new facilities) as well as NO_x emission standards for new plants after the year 2000. In both cases the proposed EU standards are more severe than new Poland's regulations. In the case this directive comes into effect Poland would consider some modifications of its legislation.

investment plans are less certain. Nevertheless, these are smaller facilities for which emission standards are less stringent and easier to fulfil (in most cases it suffices to apply better quality fuel, low NO_x burner etc.), consequently it is reasonable to expect that appropriate pollution mitigation measures would be part of their capital investment plans.

- A gradual improvement of hard coal quality (heating value, sulphur and ash content), according to the forecast of the Institute of Mineral Resources and Energy Management of the Polish Academy of Sciences.

- Adherence of new motor vehicles to national emission standards for NO_x and particulates. These standards are compatible with 1992 and 1996 EU standards (Directive 94/12/EEC and 91/542/EEC), which impose the use of catalytic converters for gasoline engines and combustion modifications on diesel engines.

- Implementation of limits on the sulphur content of transportation fuels and light fuel oil according to the Second Sulphur Protocol and new EU legislation – Directive 98/70/EC and 99/32/EC. Reduction of sulphur content to 0.035% from the year 2000 and 0.005% from 2005 for gas oil; 0.015% from 2000 and 0.005% from 2005 for gasoline; 0.2% from 2005 and 0.1% from 2008 for light fuel oil/gas oil used in stationary sources. Finally, a gradual decrease of sulphur content of heavy fuel oil down to 1% by 2010, as recommended by the Second Sulphur Protocol.

- A gradual reduction of per-GJ emission rates (30% for SO_2 and paticulates, 20% for NO_x by the year 2010) for industrial/technological processes, treated in an aggregated manner. This reduction, considered to be a conservative estimate, should come as a consequence of industry restructuring and technical modernisation, use of better quality fuels and an increased use of natural gas.

3.5.3. Airborne emission projections

Table 29 compares the IMPACTS estimates for 1997 with the official statistical data from the IOS/GUS inventory. Small discrepancies are the result of the differences between the official national energy balance and the energy balance determined by the BALANCE module of ENPEP.

TABLE 29. Pollutants emission estimates for the base year (1997)

	SO_2	NO_x	Particulates	CO_2[a]
	thousand tons	thousand tons	thousand tons	million tons
IOŚ/GUS	2175	1114	1130	364 (year ‘96)
IMPACTS	2179	1105	1135	385

[a] Emissions from production and combustion of fossil fuels

Figures 46–50 present total emission projections for major airborne pollutants in each of the three scenarios. Although some scenarios have lower emissions than others, it should be noted that emission projections do not differ significantly across cases, and general conclusions are valid for each of them. This is understandable, taking into account that scenarios do not significantly differ in the degree to which the worst pollution emitters — i.e. existing coal and lignite power plants, and small heating and co-generation stations — continue to produce power.

There are presently two airborne pollutants, sulphur dioxide (SO_2) and carbon dioxide (CO_2), that Poland is obliged to reduce in accordance with its international obligations; namely:

- UN-ECE II Sulphur Protocol (Oslo 1994) — Reduction of SO_2 emissions by 37% in the year 2000, 47% in 2005 and 66% in 2010, relative to 1980 level,
- UN FCCC (1992) and its Kyoto Protocol (1998) — Stabilisation of CO_2 emissions in the year 2000 and its reduction by 6% in the period 2008-2010 relative to 1988 level.

For comparison, these targets were superimposed on the corresponding graphs (Figs 47 and 50).

- ***Projections of national particulate emissions***: A significant decline of particulate matter emissions, about 50% reduction by the year 2010, is observed in all scenarios (Fig. 46). This is directly related to the assumptions that all stationary sources burning fossil fuels would comply with the imposed new emission standards (MOŚZNiL, 1988 [20]). In general, the greater the amount of fuel switching from coal to natural gas the lower the emissions in industry, district heating and households.

- ***Projections of national SO_2 emissions***: Despite a growing demand for fuels and energy, a steady decrease of sulphur dioxide emissions over the study horizon is noticeable (Fig. 47). The first two targets of the Second Sulphur Protocol for 2000 and 2005 can be easily met. However, the next emission level — 1400 kt after the year 2010 — although achievable, might be harder to comply with in later years. For this reason, a successful realisation of all planned undertakings for sulphur emissions reduction in the power sector is essential. No less important, however, would be a strict compliance of new emission standards by all new and existing facilities (the latter after the year 2005), a further transformation of industry towards cleaner technologies, a greater use of natural gas instead of coal in industry and residential sectors, and a systematic decrease in the sulphur content of petroleum products.

- ***Projections of SO_2 emissions in the electric power sector***: A comparison of forecasted SO_2 emissions in electric power sector (Fig. 48) with assumed [19] emission cap of 0.7 million tons/year in the year 2010, shows that the on-going program of technical and ecological modernisation of existing power plants, suffices to meet that goal. However, after 2010 a greater use of natural gas is necessary, in order to prevent a further increase in SO_2 emissions.

- ***Projections of national NO_x emissions***: Projections of NO_x emissions are shown in Fig. 49. Initially NO_x emissions decrease (till about 2006) due to the modernisation of combustion technology in coal-fired power plants (change to fluidised combustion and low NOx emission burners). Also to some extent the emissions decrease due to the replacement of old motor vehicles by new ones (equipped with catalytic reactors). After 2006 the decrease in NO_x emissions is insignificant or they increase slightly due to growing road transportation demand. It should be pointed out, that in November 1999, a new UN-ECE 'Gothenburg Protocol' to the Convention on Long Range Transboundary Air Pollution was adopted, setting, among others, annual NO_x emission ceilings for European countries for 2010. According to this Protocol, Poland would be required to limit national NO_x emissions bellow 880 thousand tons/year by 2010. Under the present assumptions this goal would not be met in any of the three scenarios. Meeting the target would require further emission reductions in both the power and transportation sectors. It should be noted that there is a greater uncertainty level related to the estimates of emissions for the transportation sector than for the others. For a more credible assessment of meeting the above NO_x emissions cap, a more detailed analysis of emissions from the transportation sector is required. This sector will continue to improve as even more stringent emission requirements are applied to new cars and trucks and newer more efficient vehicles replace older and dirtier ones.

- ***Projections of national CO_2 emissions***: Different strategies are possible to reduce CO_2 emissions such as, lower end-use of energy through energy conservation, increased efficiency in energy supply (including co-generation of heat and power), fuel substitution and promotion of renewables. These options have additional important benefits of also reducing other pollutants. All mentioned options were considered in the analysis. Figure 50 shows the total energy-related CO_2 emissions in the period 1997-2020 for the three scenarios. Taking into account that CO_2 emissions in 1997 have already decreased by about 17% compared to 1988, the Kyoto Protocol (6% reduction in the period 2008–2010, compared to 1998 level) is relatively easy to achieve. By 2010, Polish CO_2 emissions will level off at an annual rate that is 15–20% lower than in the baseline year of 1988. However, accession of Poland to the European Union might by conditioned by more stringent requirements for greenhouse gas emissions, for example stricter reduction levels or requirement for the stabilisation of emissions beyond 2010 may be imposed.

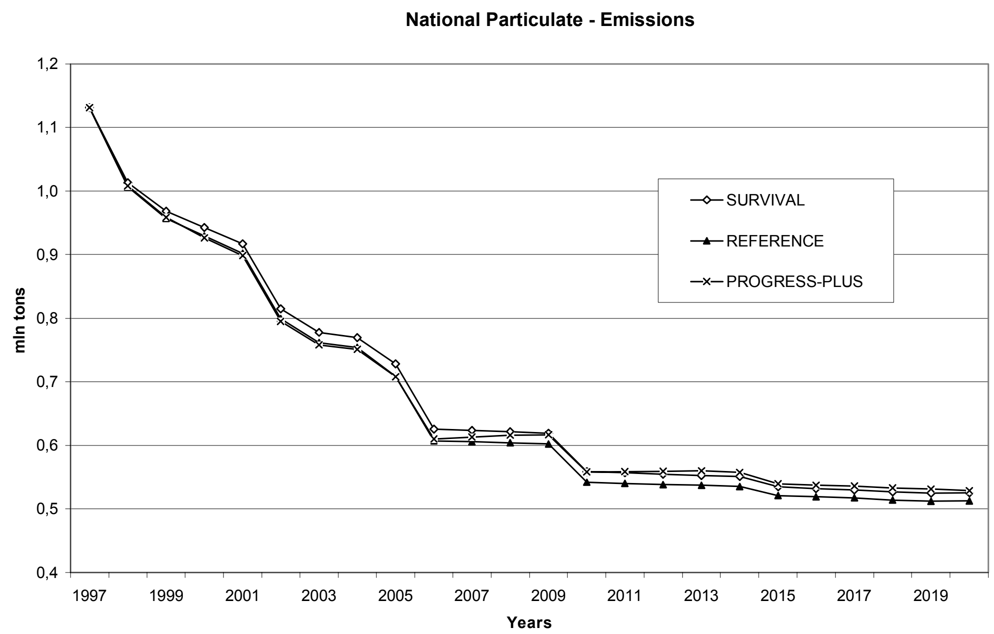

FIG. 46. Particulate emission projections.

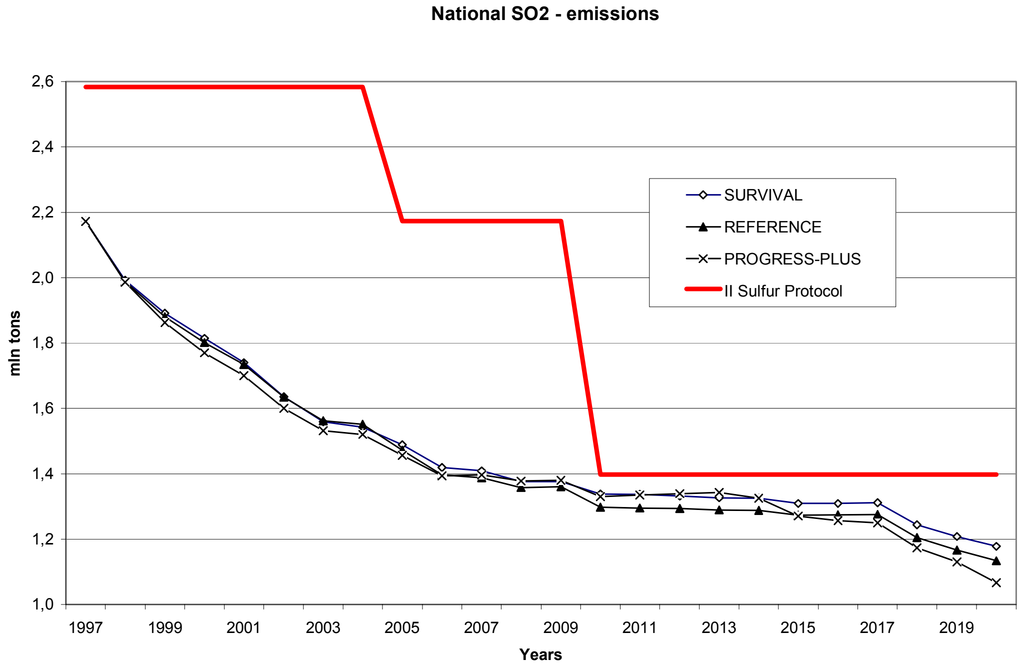

FIG. 47. Sulphur dioxide emission projections.

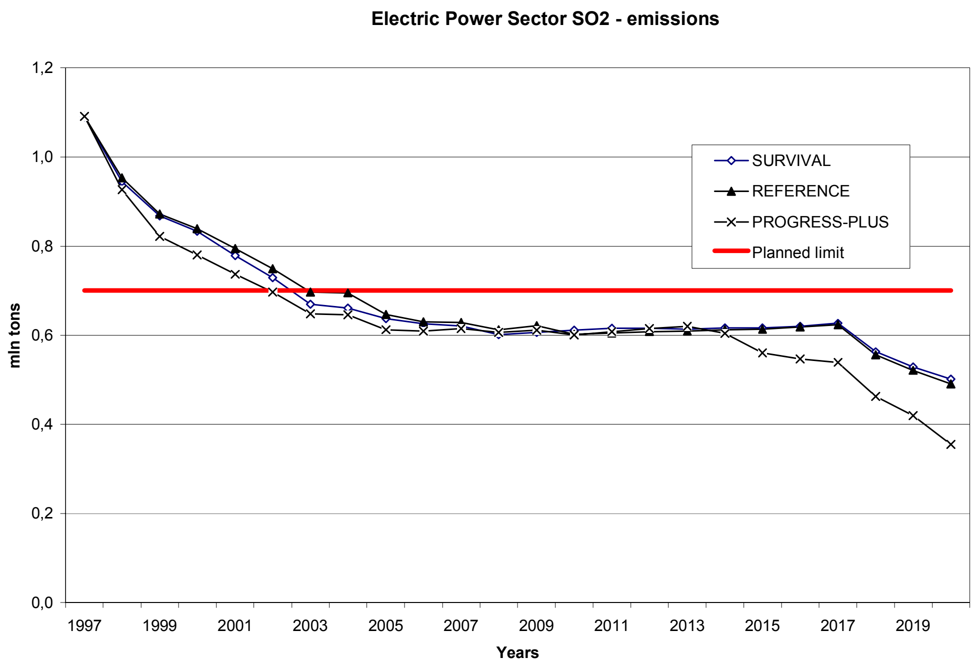

FIG. 48. Projections of sulphur dioxide emissions in electric power sector.

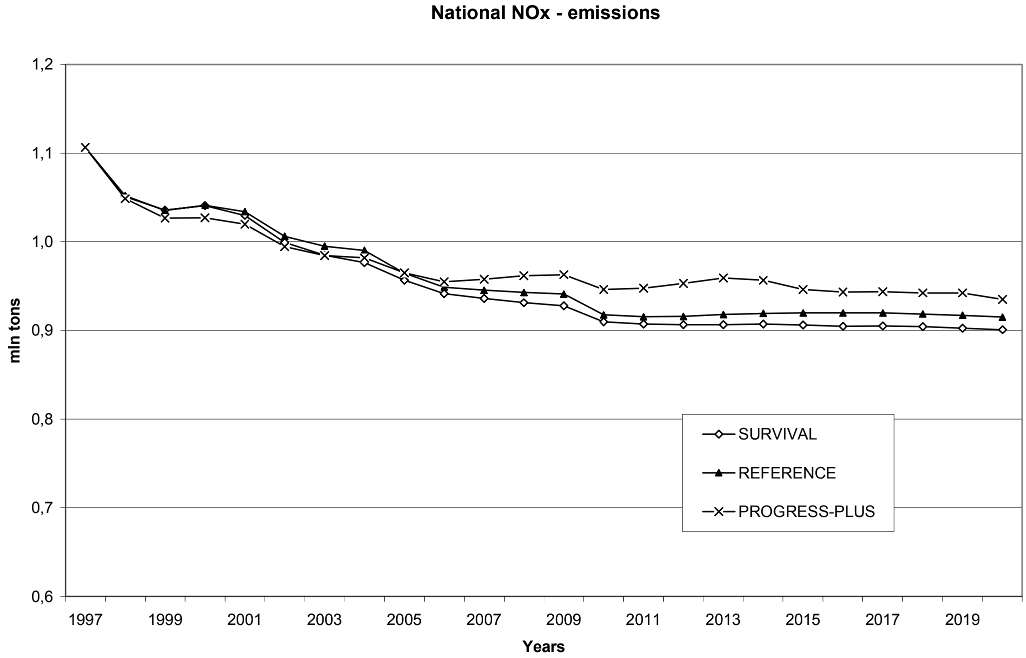

FIG. 49. Nitrogen oxides emission projections.

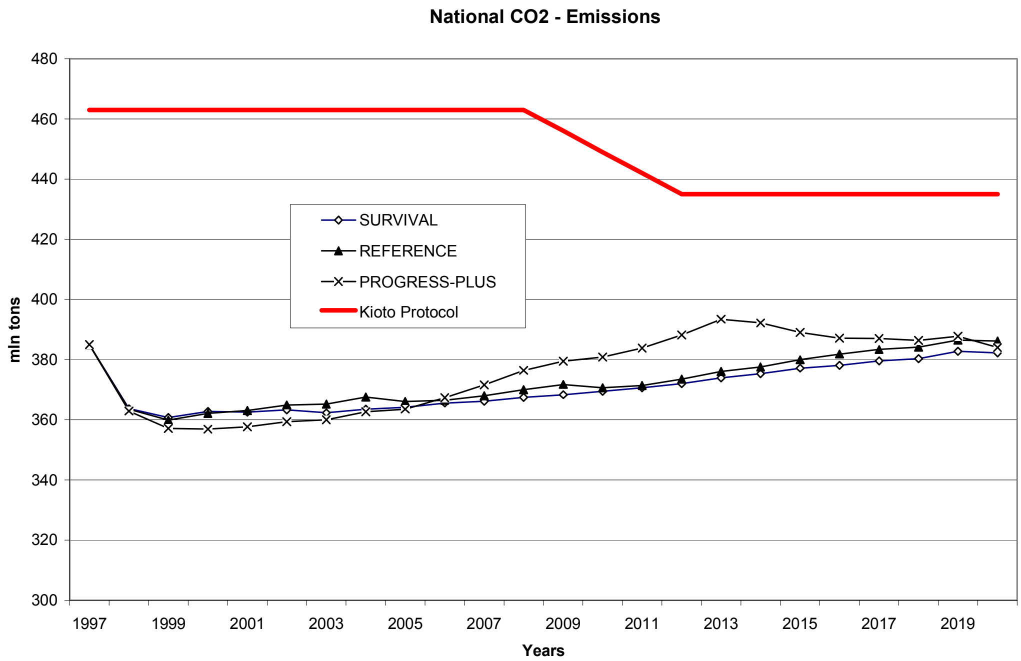

FIG. 50. Carbon dioxide emission projections.

3.6. Conclusions

Long-term fuel and energy demand forecasts were performed based on three macroeconomic scenarios. These scenarios take into account different paces of growth of the Polish economy in the transition period and reflect its capability of adapting to various external conditions. Depending on the scenario, the assumed average annual economic growth ranges between 2.3% and 5.5%. The results of the analysis should provide an insight into the possible impacts of key policy decisions by describing possible states of the Polish energy sector in the next 20 years, subject to the dynamics of change of different phenomena characterising the particular scenario. The most important conclusions are summarised below.

1. Generally a small to moderate (below 0.1 to 0.5%) yearly increase in final energy demand (FED) has been projected. It is noticeable that in all scenarios a 5–7% decrease of total final energy demand is projected till the year 2005, and only thereafter a gradual rise is observed. Nevertheless, the final energy demand per capita in Poland will remain significantly below corresponding values for the EU countries.
2. The demand for electrical energy will grow in all sectors faster than the total energy demand (2-3% average annual growth rate), with the most significant increase expected in the residential and commercial sectors.
3. An annual decline of 2 to 4% in the use of district heat is predicted, due to a generally lower demand in the commercial/residential sector and industry (conservation and more efficient use of energy) and to some extent due to an increased local heat production.
4. The projected primary energy requirement in 2020 ranges from 112.2 to 121.3 Mtoe. This is below the 1988 level. Also, there are significant changes in the future structure of energy carriers.
5. It is projected that hard coal has the highest share in total demand but it decreases strongly, from about 56% in 1997 to below 45%. Hard coal remains the main energy carrier for power and heat co-generation, where its use moderately but steadily increases over the study period. Due to overall demand increase, the share of lignite diminishes, although the level of its production stays virtually unchanged.
6. Independent of scenario, the share of natural gas will continue to increase rapidly. It more than doubles in 2020 compared to 1997. For electricity generation, gas constantly increases its share from virtually zero in 1997 to between 11 and 15% in 2020. This requires large gas imports and also lowers the security of supply. Therefore, diversification of gas suppliers becomes important.
7. A modest increase in the liquid fuels share is projected, which is of importance since crude oil comes almost completely from imports.
8. Due to low cost-effectiveness, the current low share of renewable energy sources will not change significantly, and will remain below 6.5%. Special promotional measures would have to be taken if the share of renewables in the overall energy mix is to be increased.
9. New public generation plants appear only after 2013. These plants are mainly combined cycle gas turbines (GTCC) and peaking gas turbine plants (GT).
10. Large-scale combined heat and power for district heating and industrial applications, as well as small CHP applications have a large long-term cost-effective potential (about 35% to 40% of total electricity production, i.e. more than two-fold increase in comparison to 1997 level). Particularly significant increases of distributed generation can be expected, among which small gas fired co-generation plants prevail.
11. No nuclear power is forecasted in any scenario over studied planning period.
12. Whereas Poland currently has a high index of energy self-sufficiency (above 80%), a steady decline of this value is projected over the next two decades to about 60%. That level is still above the present average value for EU countries. However, increased imports will have a positive impact on fuel diversity that is beneficial to security of supply.

13. Independent of scenario, all energy productivity indicators for Poland remain below 50% of the expected average values for EU countries.
14. A 50% reduction in particulate matter emissions by the year 2010 is projected in all scenarios.
15. The first two targets of the Second Sulphur Protocol for the year 2000 and 2005 can be easily met. However, the next emission level — 1400 kt after the year 2010 — although achievable, might be harder to comply with in later years.
16. Despite the projected large decreases in NO_x emissions, meeting the target set by the UN-ECE 'Gothenburg Protocol' would require further emission reductions in both the power and transportation sectors.
17. The Kyoto Protocol mandates a 6% reduction of greenhouse gases emissions in the period 2008-2010, relative to the 1998 level. This target appears to be relatively easy to achieve. By 2010, CO_2 emissions will be 15–20% lower than in the baseline year of 1988.

4. POWER MARKET ANALYSIS

An analysis of the Polish power system investigated the potential role that small-scale combined heat and power (CHP) plants may play during a peak load situation. The economic value of CHP plants and the short-term financial gains that CHP owners may gain was also estimated. A candidate gas-fired CHP plant was located in the region with the highest economic cost of energy.

A second object of the power systems analysis is to estimate the potential for east-to-west power transfers across Poland. The Polish Power Grid could potentially reap financial gains by purchasing energy from an adjoining power system to its east at a relatively low price and resell this energy to its west at a higher price. The Polish Power Grid Company could also wheel energy for a third party for a service fee.

4.1. Modeling methodology

The Generation and Transmission Maximization (GTMax) model simulates the dispatch of electric generating units and the economic trade of energy among utility companies using a network representation of the power grid. Generation and energy transactions serve electricity loads that are located at various locations throughout the simulated region. Links and transformers connect generation and energy delivery points to load centers. Electricity loads are satisfied, curtailed via contractual agreements, or not served due to a generator supply shortage or because of transmission limitations.

The objective of GTMax is to maximize the net revenues of power systems by finding a solution that increases income while keeping expenses at a minimum. When multiple systems are simulated, GTMax identifies utilities and projects that can successfully compete on the open market. The model computes and tracks hourly energy transactions, market prices, and production costs. Using a mixed integer Linear Programming (LP) approach GTMax simultaneously solves the maximization objective for all hourly time steps in a weekly simulation period. The model can be run for all 52-weeks in a year or for selected weeks that are representative of a month or a season.

Simulated activities are driven by energy market forces and are performed within the physical and institutional constraints of the interconnected systems. Some limitations that are modeled include power plant seasonal and hourly maximum and minimum generation levels, limited energy constraints, contractual transmission capabilities, and terms specified in firm and IPP contracts. GTMax also considers detailed operational limitations such as power plant ramp rates and hydropower reservoir constraints. Firm transmission contracts, along with Transmission Reliability Margins (TRM) and Capacity Benefit Margins (CBM) are also factored into model simulations. GTMax computes Available Transmission Capabilities (ATC) for each transmission link, over Composite Transfer Capability (CTC) link groups and over user-specified pathways.

The model is designed to be user-friendly. It operates under a Microsoft Windows environment and employs a Geographical Information System (GIS) interface. The user builds power system components and interconnections using mouse point and click actions. By clicking on a map of utility power plants and transmission lines input data can be viewed and modified. Model results for hourly energy flows from supply resources such as generators and IPP firm contract purchases to load centers and spot market delivery points are graphically displayed on a map. The user can also simultaneously view two or more scenarios at once. GTMax also produces financial reports.

4.2. GTMax network components

The GTMax model utilizes a node and link network representation of a power system. Nodes in the system represent various generation supply options, substations, market hubs, electricity loads, firm purchase and sales contracts, power exchange points, and points of energy interchange. The model also contains nodes that represent the market for energy at interconnection points with systems that border the simulated region. Links represent transmission and distribution systems and waterway systems that connect cascaded hydropower systems. The GTMax model is very versatile in that the user starts with an empty workspace and builds a power system topology of nodes and links via the GIS interface. Each node and link in the network contains information for many variables that is contained in a database. Inputs are separated into three categories that include weekly, daily, and hourly variables. As the category name imply weekly variables remain constant throughout a simulated week, while daily variables are specified for each day of the week and hourly variables are specified for each hour of a simulated week (i.e., 168 input values).

4.2.1. GTMax model topology

The Polish power grid was modeled as a set of interconnected power regions or power pools. As shown in Fig. 51, there are a total of five regions that consist of the following: (1) Central, (2) Eastern, (3) Southern, (4) Western, and (5) Northern. The characteristics of these regions in terms of loads are provided in Figs 52–56 for a peak load day (Thursday) and an off-peak load day (Sunday). The loads shown in the figures are for the 48th week of the year; that is, an early December week which is typically the peak load week in the year. Hourly loads are not publicly available at the regional level. Therefore, the loads shown in the figures are estimates based on actual regional loads for the peak hour in 1998 and hourly load profiles for the entire Polish power grid. These total system-wide loads are available for all hours of the year. Regional load fractions for the peak hour were derived and applied to country-wide loads profiles to estimate regional loads in all other hours in the year.

Tables 30 through 34 show the characteristics of generation resources in the five regions. It should be noted that there is an imbalance of supply resources and electricity demand in some regions. For example, in the northern region the peak hourly load including losses is more than 2,700 MW while generation resources are about 1,585 MW. On the other hand, the central region has an excess supply with a peak load of about 4,600 MW and generation resource of more than 6,600 MW.

Regional supply and demand imbalances are rectified through the transfer of power and energy via the Polish transmission network. Tables 35–36 show the transfer capacity of major lines that connect the regions. The total transfer capabilities (TTC) that were input into the links shown in Fig. 51 were based on load flow modeling analyses that estimates transfer capabilities between regions for equivalent or aggregate lines that both directly and indirectly link regions. These transfer capabilities typically exceed those shown in Tables 35–36 since other smaller lines not shown in the table also add to the transfer capability.

4.2.2. CHP technology description

The small combined heat and power (CHP) plants investigated in this study are local natural gas fired plants. The technology assumed is the natural gas reciprocating (internal combustion) engines. Reciprocating engines are available in a broad size range of 50 kW to 10 MW suitable for a wide variety of residential, commercial and industrial applications,

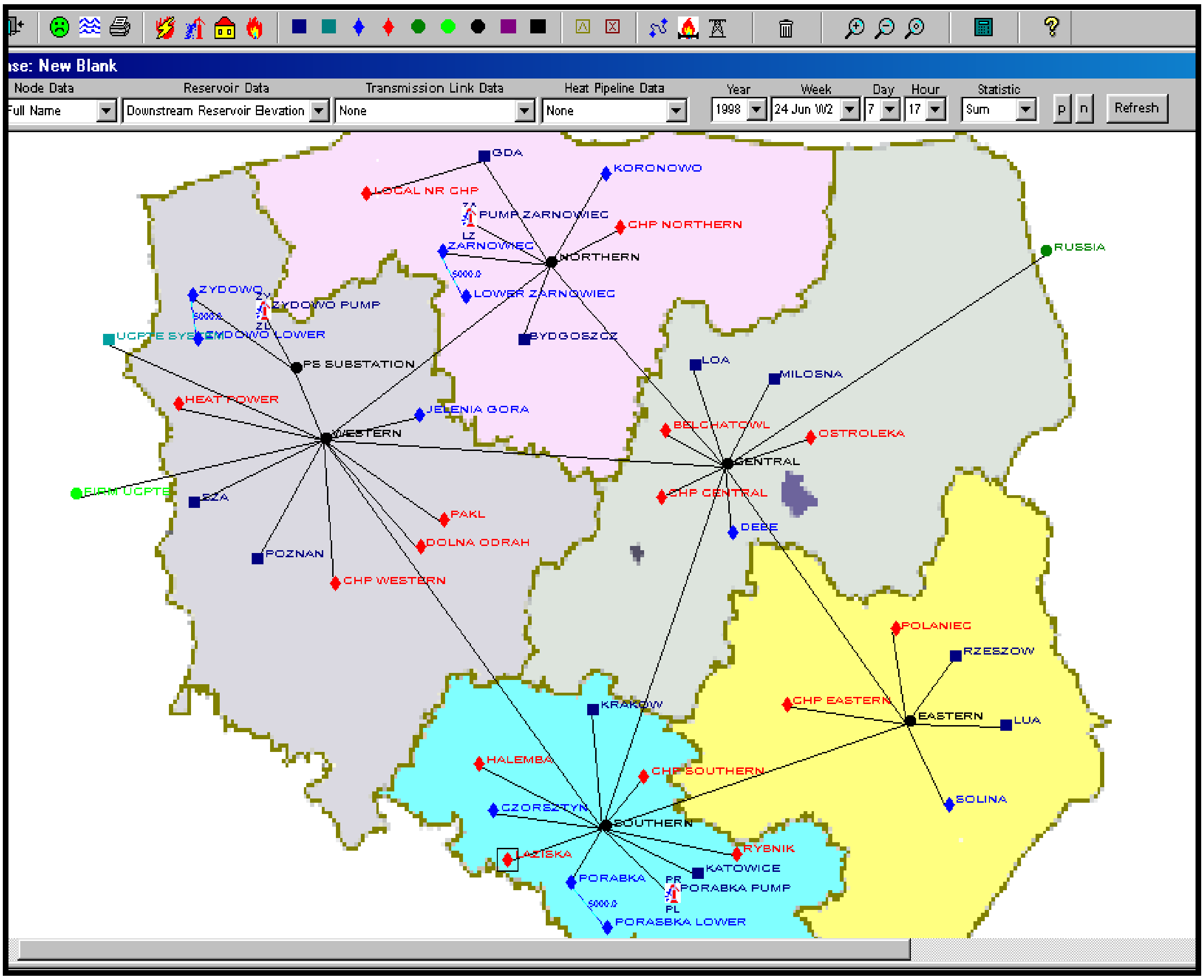

FIG. 51. Topology of the Polish power grid network that is used in the GTMax model.

typically where there is a substantial hot water demand. The assumed size of a local CHP plant is 24 MWe. The other main assumptions are:

— The plant operates only during the heating season (approximately 5100 h/year), i.e. outside that season the thermal balance is achieved through supplemental heat sources such as gas boilers.

— Furthermore, the plant operates only during periods of high loads (peak and shoulder hours), approximately 3000 hours/year, and is switched off during the periods of low demand,

— The assumed operation of the small CHP plant is regulated for heat on a seasonal basis. However, since the CHP plant has heat storage capabilities, the hourly operation of the plant takes advantage of the daily price profile of the electric energy market. Therefore, the CHP plant is operated mainly during the daytime when the associated electricity production reaps the most money. Excess heat production during the daytime is used during the night when the plant does not operate. For this analysis it was assumed the power plant would operate 14 hours per day (from 9 a.m. to 10 p.m.) for 7-days per week during the heating season.

— The assumed incremental electricity generation cost is 10 USD/MW·h
— A candidate CHP power plant was located in the northern region since this region has a negative reserve margin and has the highest hourly value of energy.
— Transmission and distribution losses are assumed to be negligible since the CHP plant is assumed to be located very near to the load.

4.2.3.1. Central region

The basic characteristics of the Central region are shown in Fig. 52 and Table 30. The available capacity amounts to around 6600MW; that is, 22% of the total Polish power system capacity. The biggest plant in Poland is the lignite-fired Bełchatów facility. This one power plant accounts for 65% of the generation capacity in the Central region. The rest of capacity is mostly coal-fired CHP plants. For that reason, among all regions the Central one has the lowest average generation costs. Net generation in 1998 was about 35 TW·h, that is approximately 29% of the total power generation in Poland. The peak demand was around 4600 MW, i.e. 20% of the national peak demand. The Central region is a net power exporter.

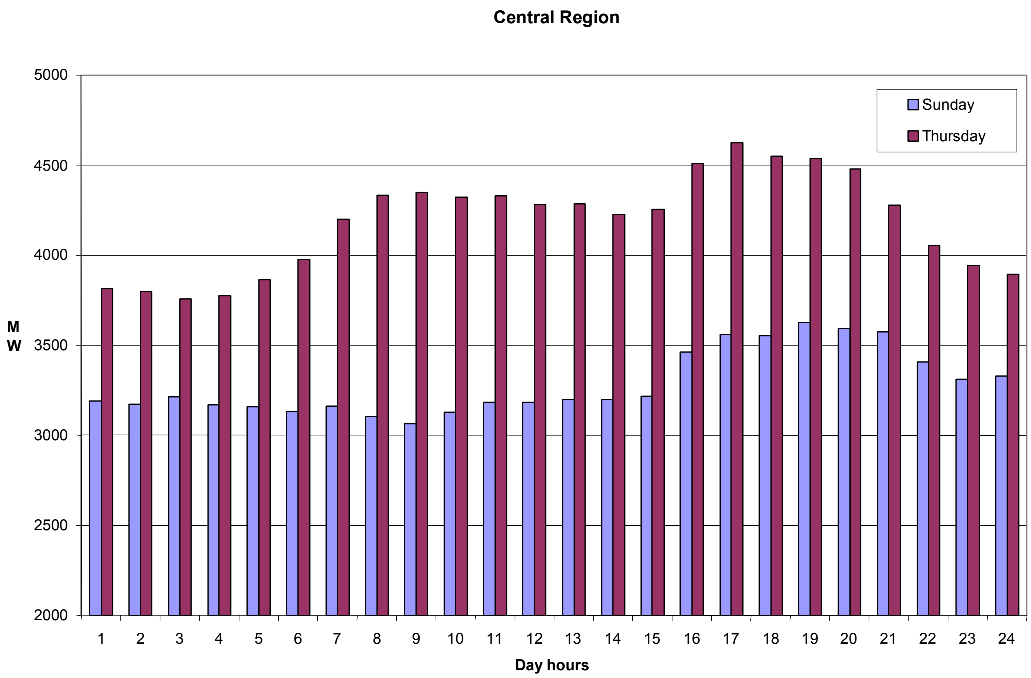

FIG. 52. Central region load profile (48th week, year 1998).

TABLE 30. Central region available capacities, net electric energy production and average generation costs in 1998, aggregated by plant type

CENTRAL REGION	Available capacity	Net generation	Generation cost Fixed	Variable	Total
	MW	GW·h	USD/MW·h		
Hard Coal Power Plants	600,0	2494,0	9,61	22,83	32,44
Lignite Power Plants	4320,0	26932,4	8,28	11,11	19,39
Combined Heat and Power Plants	1678,60	5805,66	12,87	14,32	27,19
Hydro Power Plants	16,70	120,80	8,61	0,00	8,61
ALL PLANTS	**6615,3**	**35352,9**	**9,13**	**12,43**	**21,55**

4.2.3.2. Eastern region

The load profile and basic generation data of the Eastern region are shown in Fig. 53 and Table 31. The available capacity is almost exclusively from two largest Polish coal-fired power plants (Kozienice and Połaniec) that represent about 17% of the total country's available power. Net generation in 1998 amounted to about 15 TW·h, i.e. 12% of the total generation. The total generating capability of the region is over 5000 MW while the peak demand was a little over 3000 MW, i.e., 13% of the total peak demand in the country. A high reserve margin in the region allows it to export power to other parts of the country.

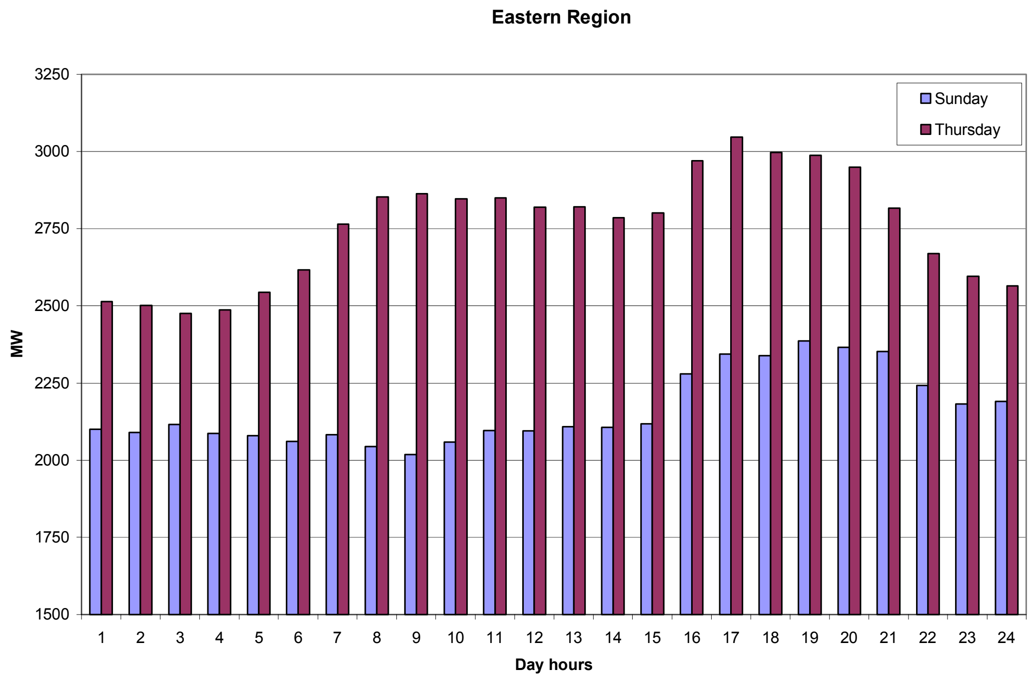

FIG. 53. Eastern region load profile (48th week, year 1998).

TABLE 31. Eastern region available capacities, net electric energy production and average generation costs in 1998, aggregated by plant type

EASTERN REGION	Available capacity	Net generation	Generation cost		
			Fixed	Variable	Total
	MW	GW·h	USD/MW·h		
Hard Coal Power Plants	4785,6	14721,3	12,76	18,98	31,73
Combined Heat and Power Plants	95,7	207,9	17,00	14,54	31,54
Pumped Storage Hydro Plants	140,0	203,4	36,15	0,00	36,15
ALL PLANTS	**5021,3**	**15132,6**	**13,13**	**18,66**	**31,79**

4.2.3.3. Southern region

The Southern region encompasses one third of the national electric power capacity and has approximately the same share of the electricity generation (Table 32). The peak demand (Fig. 54) in 1998 was around 7000 MW, i.e. 30% of the national peak demand. There are no lignite-fired facilities in this region. Above 80% of available capacity comes from hard-coal power plants, about 10% are coal-fired CHP plants and the rest are hydro facilities that are mostly pumped storage. Coal prices and hence variable production costs in this region are fairly low. This region has the most of hard coal production in Poland and transport costs are relative low. However, due to high fixed costs the Southern region has the highest total generation costs in Poland. For example, total generation costs are more than 50% higher than in the Central and Northern regions.

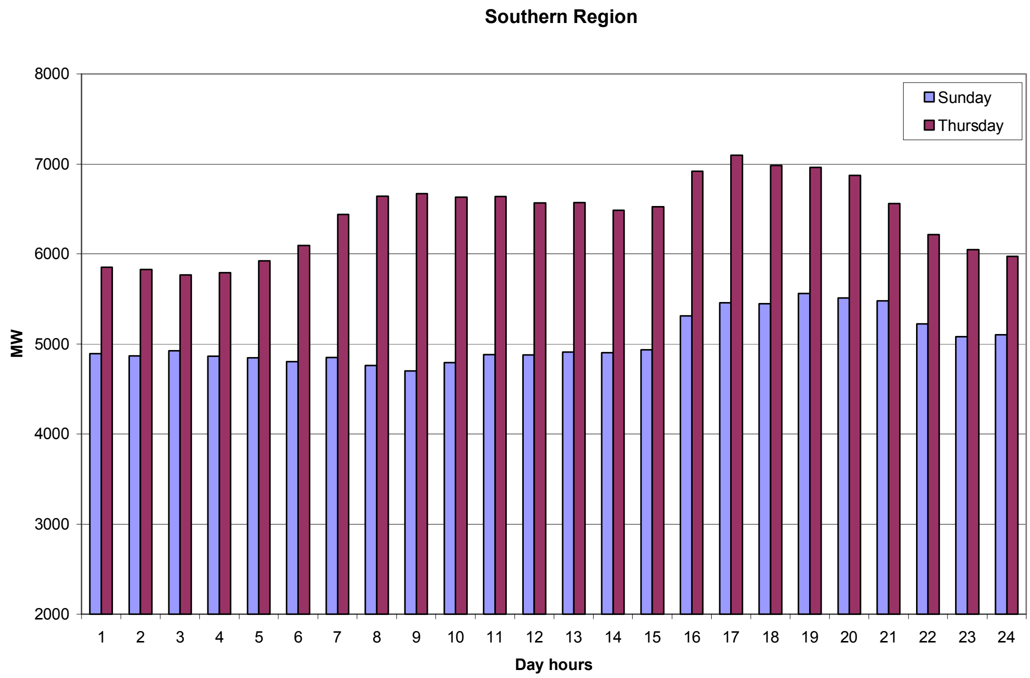

FIG. 54. Southern region load profile (48th week, year 1998).

TABLE 32. Southern region available capacities, net electric energy production and average generation costs in 1998, aggregated by plant type

SOUTHERN REGION	Available capacity	Net Generation	Generation cost Fixed	Variable	Total
	MW	GW·h	USD/MW·h		
Hard Coal Power Plants	8151,0	32738,9	17,22	17,88	35,10
Combined Heat and Power Plants	1068,4	3558,1	14,55	16,58	31,13
Hydro Power Plants	58,1	252,8	19,50	0,00	19,50
Pumped Storage Hydro Plants	534,0	689,7	20,01	0,00	20,01
ALL PLANTS	**9811,5**	**37239,6**	**16,66**	**17,30**	**33,96**

4.2.3.4. Western region

The basic data depicting the Western region are shown in Fig. 55 and Table 33. The available capacity is about 6750 MW (i.e. 23% of the total system capacity), providing approximately one quarter of the country's electric power supply. Similarly, the peak demand is about one quarter of the national peak demand. Above 60% of the available power is provided by the lignite-fired power plants.

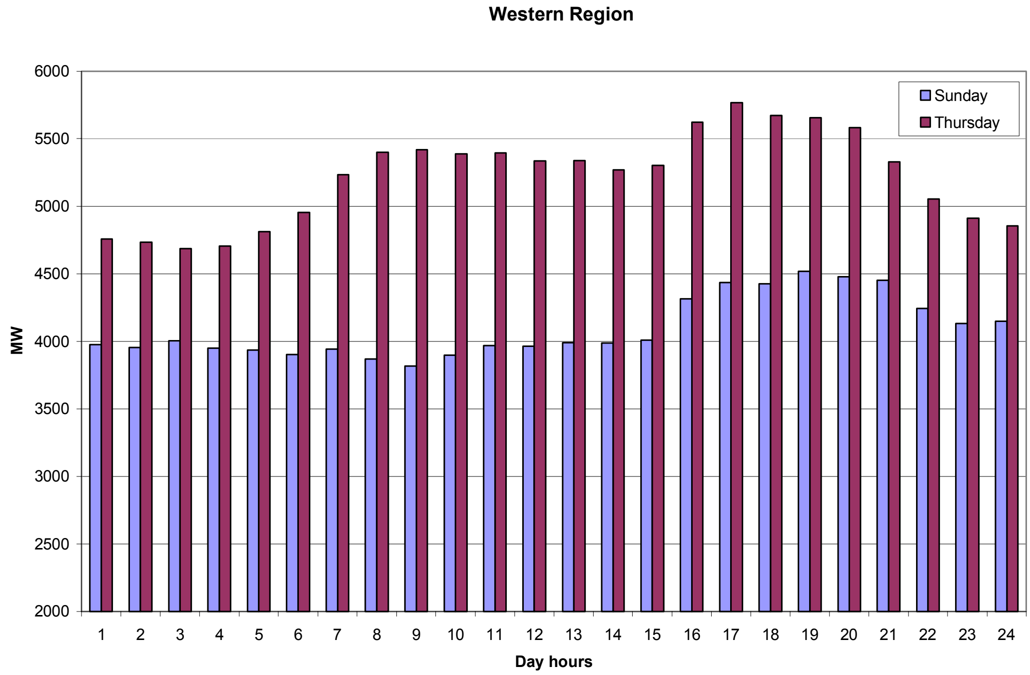

FIG. 55. Western region load profile (48th week, year 1998).

TABLE 33. Western region available capacities, net electric energy production and average generation costs in 1998, aggregated by plant type

WESTERN REGION	Available capacity	Net generation	Generation cost		
			Fixed	Variable	Total
	MW	GW·h	USD/MW·h		
Hard Coal Power Plants	1708,0	6305,8	12,32	21,63	33,95
Lignite Power Plants	4131,1	20795,7	9,11	17,82	26,93
Combined Heat and Power Plants	782,5	2735,2	14,65	16,56	31,20
Hydro Power Plants	29,4	203,6	29,54	0,00	29,54
Pumped Storage Hydro Plants	96,0	141,4	64,31	0,00	64,31
ALL PLANTS	**6747,0**	**30181,6**	**10,68**	**18,30**	**28,98**

4.2.3.5. Northern region

The Northern region is characterised by the smallest generation capacity (Table 34), representing only about 5% of the national total. Its share in the total net generation is even smaller, only about 3.5%. On the other hand, its peak demand is about two and a half times greater than the available capacity (Fig. 56), hence the need to import energy.

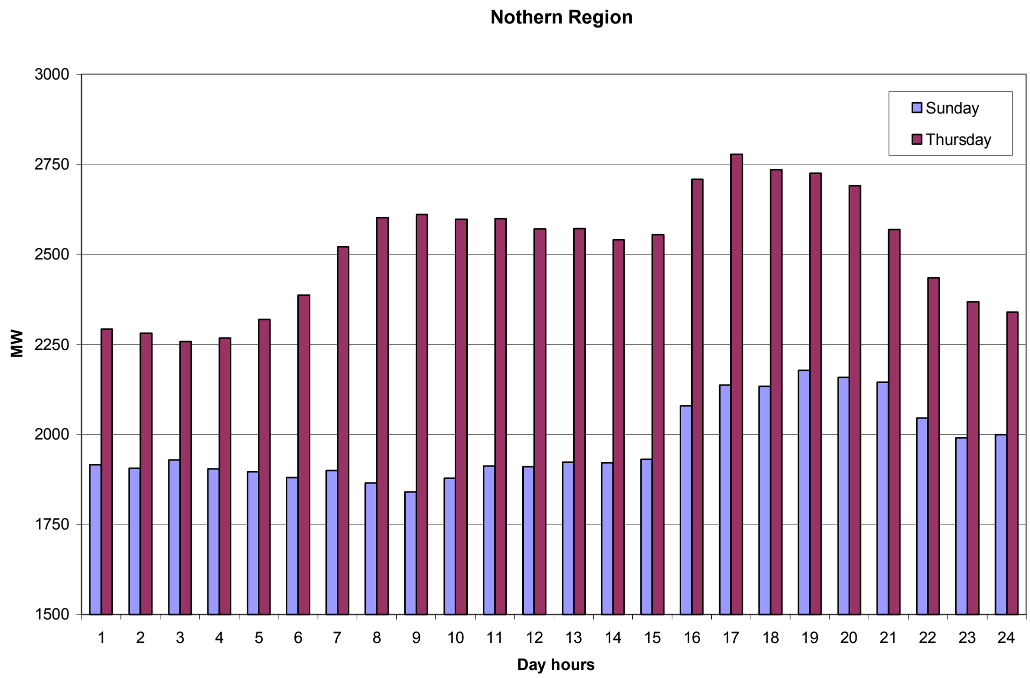

FIG. 56. Northern region load profile (48th week, year 1998).

TABLE 34. Northern region available capacities, net electric energy production and average generation costs in 1998, aggregated by plant type

NORTHERN REGION	Available capacity	Net generation	Generation cost		
			Fixed	Variable	Total
	MW	GW·h	USD/MW·h		
Combined Heat and Power Plants	521,6	1999,7	15,67	15,46	31,13
Hydro Power Plants	347,0	1295,3	9,08	0,00	9,08
Pumped Storage Hydro Plants	716,0	1062,1	23,00	0,00	23,00
ALL PLANTS	**1584,6**	**4357,1**	**15,50**	**7,10**	**22,59**

4.2.3.6. Transmission system

The transmission system includes all 400 kV and 220 kV power lines between the five regions as well as between Poland and UCPTE. Power flow limits of the transmission system are shown in Table 35. The transmission capabilities that were assumed in GTMax are shown in Table 36. These assumed capabilities are higher than those in Table 35 since additional lines with voltages lower than 220 kV also link regions together.

Presently there are no bottlenecks in the transmission system. However, some transmission paths are at times heavily loaded with economic bulk power transfers. In normal situations the transmission capability is adequate for transporting all economic power transfers. In extreme situations such as, for example, outages of large plants or labour problems, the transmission lines may be more heavily utilised resulting in insufficient transfer capabilities and in unserved energy in the transmission-constrained regions.

TABLE 35. Interregional transmission capacities of 400 kV and 220 kV lines

Transmission Lines		Total capacity
From	To	**MW**
Central Region	Eastern Region	2027
Central Region	Southern Region	6513
Central Region	Western Region	1684
Central Region	Northern Region	1295
Eastern Region	Southern Region	3766
Southern Region	Western Region	1329
Western Region	Northern Region	2254
Poland	UCTE	10404

TABLE 36. Total Transfer Capabilities Asssumed in the GTMax Model

Transmission Lines		Total capacity
From	To	**MW**
Central Region	Eastern Region	2432
Central Region	Southern Region	7816
Central Region	Western Region	2021
Central Region	Northern Region	1554
Eastern Region	Southern Region	4519
Southern Region	Western Region	1595
Western Region	Northern Region	2705
Poland	UCTE	10404

4.3. Modelling results

The GTMax model was run for the week that has the highest hourly load. This run was compared to a load flow analysis for the peak load hour. Model results were also generated for all other hours in that week. Based on these results the costs and expenses for a candidate CHP power are computed. Also, the net transfers of power from east to west through Poland were investigated in terms of the costs of power transfers. Power transfer costs are mainly attributed to additional losses in the grid. Power transfers may also distort the economic dispatch of power plants.

4.3.1. Modelling the peak hourly load

The dispatch of the power system to meet loads in the peak hour of the year was simulated by both the ROZPLYW load flow model and GTMax. A comparison of the two model results was then performed. Figure 57 shows GTMax model results for the peak hour that was assumed to occur at 5 pm on Thursday of the 48th week (early December) of the year.

The figure shows the dispatch of thermal power plants (numbers associated with the red diamonds) and hydropower plants (numbers associated with the blue diamonds). Generation is used to serve regional loads (numbers associated with the dark blue squares) and firm energy sales (numbers associated with green circles). Estimates of the marginal value of energy are shown at market hubs (green numbers associated with black circles) and the loads for pumping water are also displayed (numbers associated with the pumping symbols). The contractual flow of power is displayed adjacent to links that connect the regions. Lines colored red have estimated transfers that are near the assumed maximum transfer capability while those colored blue are utilized well below the maximum transfer capability.

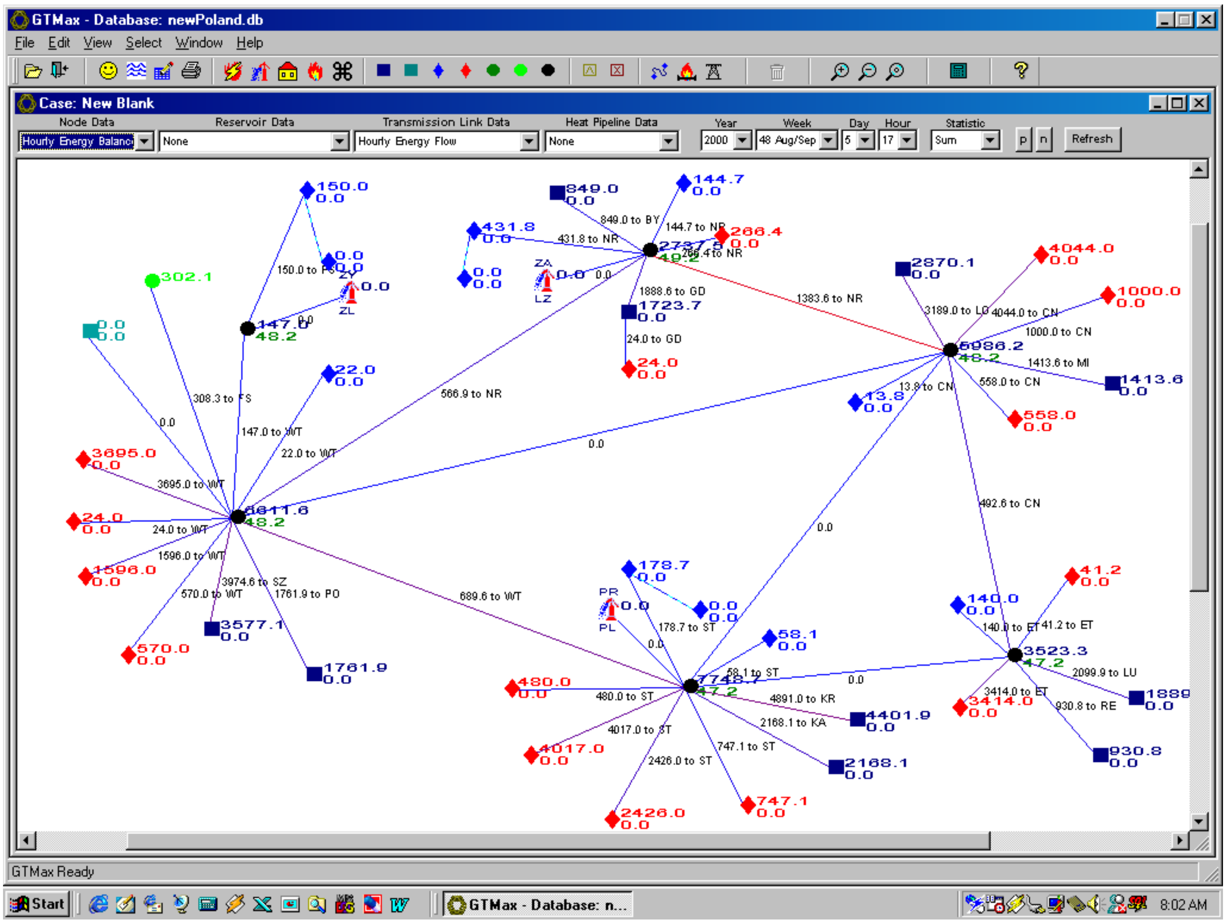

FIG. 57. GTMAx model results for the annual peak load.

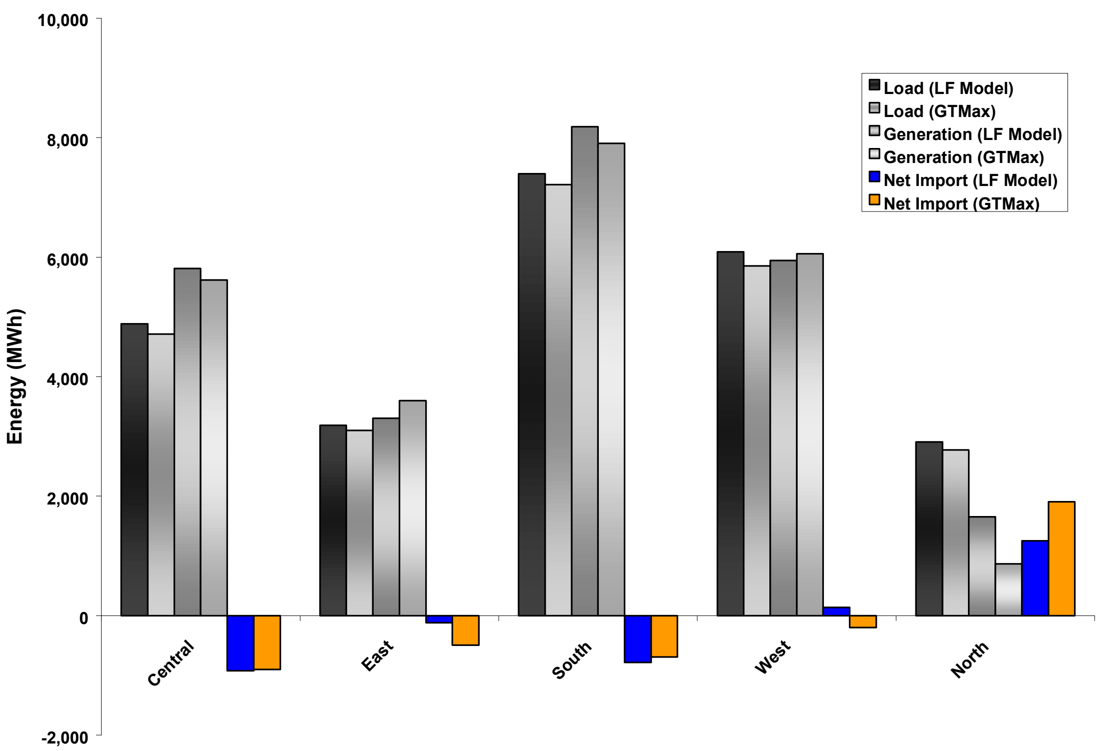

FIG. 58. Regional comparison of ROZPLYW and GTMax model results.

A comparison of GTMax model results with those projected by the ROZPLYW load flow model are shown in Fig. 58. Whereas the GTMax model estimates the dispatch of power plants, power plant generation levels are provided by the user as energy injections at various specified locations in the grid in the ROZPLYW model. The energy injection points and levels were based on pre-schedules or planning dispatch studies. The figure shows that for all regional loads, generation, and net energy imports are very similar. In general loads are slightly higher in the ROZPLYW model than in GTMax. Also, GTMax projects somewhat lower generation levels for the Northern region. This is mainly attributed to the lower utilization rate of the pumped storage power plant in GTMax versus the utilization rate assumed in ROZPLYW. A more detailed explanation of pumped storage is provided later in this section.

4.3.2. Estimates of the marginal energy production costs

The GTMax model was used to estimate the delivered price of energy to regional market hubs in the Polish power grid. These delivered prices are based on marginal production costs and both transmission losses and costs. Regional costs projected by GTMax may be significantly different among regions. However, in the simulations performed in this analysis regional price difference were small (typically within 5%) because there were no significant congestion projected in the transmission network. This is consistent with actual operations under most situations.

The average price of delivered energy to the five market hubs (one for each region) along with loads for the simulated week is provided in Fig. 59. Prices are mainly a function of load, whereby energy is the cheapest during off-peak hours and are the most expensive during the highest demand periods. Market prices range from less than 29.4 \$/MW·h on Sunday morning to almost 50 \$/MW·h during late afternoon of three weekdays (Tuesday, Wednesday,

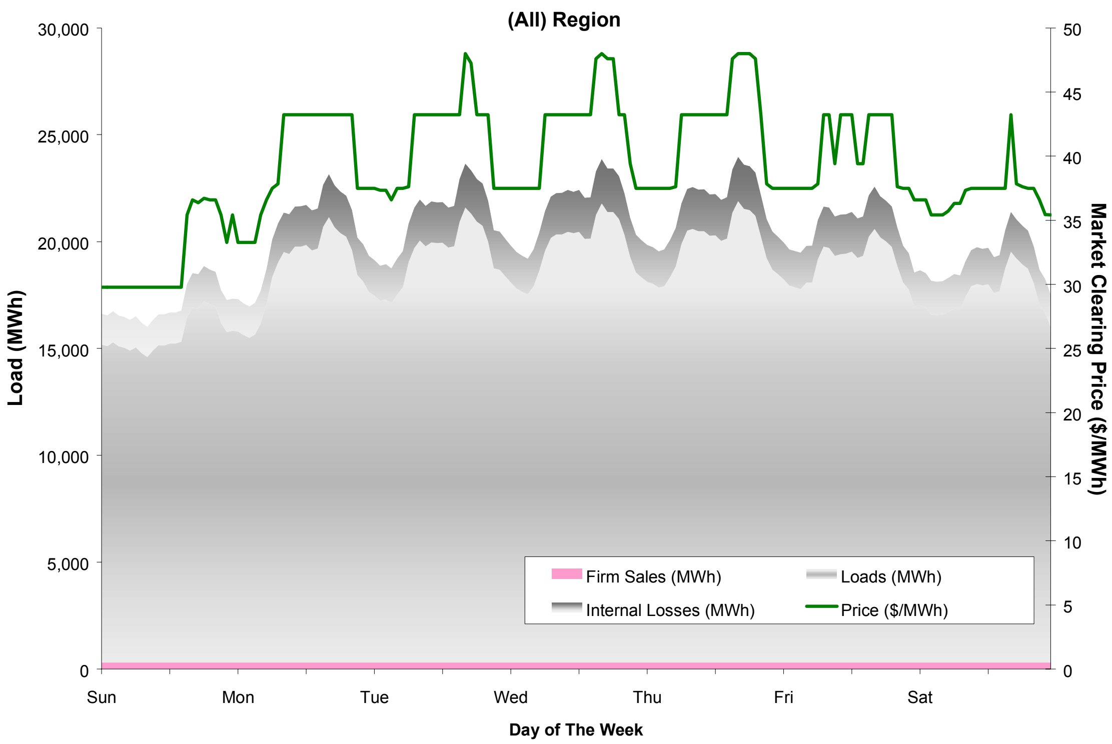

FIG. 59. Projections of market clearing price during the peak load week.

and Thursday); that is, a price difference over 65%. The off-peak price is set by the marginal production cost of electricity for CHP plants in the Central region and the on-peak price is set by marginal production costs for the pumped storage power plants. This includes the cost to purchase off-peak power and pumping losses.

4.3.3. Weekly operations

The GTMax model solves the dispatch of the power system on an hourly basis for a week time period. Some variables in the dispatch problem are independent of time; that is, the solution for one hour does not affect a future potential position or operation level. For example, a gas turbine can change operation from no production in one hour to its maximum output level in the next hour. Other variables are time dependent such that the operation in one hour of the week has an impact on its operation in other hours of the week. For example, energy drawn from the grid to pump water from a lower reservoir to an upper reservoir at a pumped storage power plant will be used to generate electricity in a future hour. Also, some technologies such as large coal-fired and nuclear plants have relatively slow ramp rates.

Figure 60 shows the operation of power plants during the peak load week. Thermal power plants serve a large majority of the load. However, although a small portion of the total energy market is served by pumped storage and storage hydro power plants, these technologies play an important role in moderating hourly price volatility. During Sunday and on some weekday nights pumped storage power plants consume relatively inexpensive energy thus helping to prop up prices. On the other hand, during the highest on-peak periods this stored energy is used to serve load that helps to moderate high on-peak prices. As shown on Fig. 61, the operation of the pumped storage power plant fills load valleys and shaves peak loads. It should also be noted that storage hydro power plants are also used to reduce on-peak loads put on the thermal system.

The reservoirs associated with the pumped storage plants have about 2 to 3 hours of storage capacity. Due to this limited capacity, the relatively low energy price during Saturday is not taken advantage of since in GTMax, filling takes place mainly on Sunday when prices are the lowest. There is sufficient pumping capacity to fill upper reservoirs during Sunday and pumping on Saturday would result in a higher overall cost of operation. Even though the price is lower on Saturday compared to weeknights there are small amounts of additional pumping on weeknights to refill reservoirs for release during the next day.

It should be noted that the actual operations of the pumped storage power plants in Poland differ somewhat from these model results. Actual daily operations fill and release the entire upper reservoir on a daily basis. Actual operations are not driven only by costs but also by dispatching center rules. This mode of operation may be partly the result of historical operations when there was a capacity shortage in the system. Also consumption during the night is at times used for voltage control in the Northern region. Transmission voltages are not taken into account in GTMax. However, by placing additional operational rules in GTMax (i.e., setting minimum daytime water releases) GTMax can reproduce actual operations and the need for voltage control.

GTMax pumped storage operations are driven by market price signals. Fig. 61 shows that pumping occurs when energy prices are low and for generation when prices are the highest.

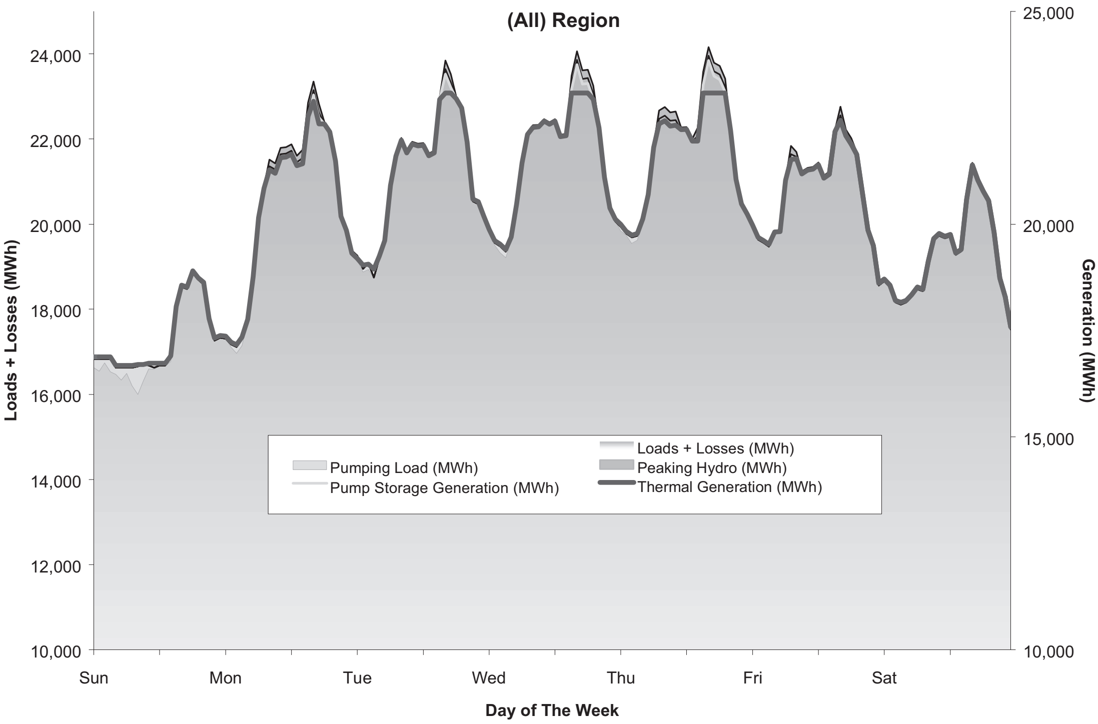

FIG. 60. Weekly operations of the Polish power suppy resources to meet loads during the peak demand week of the year.

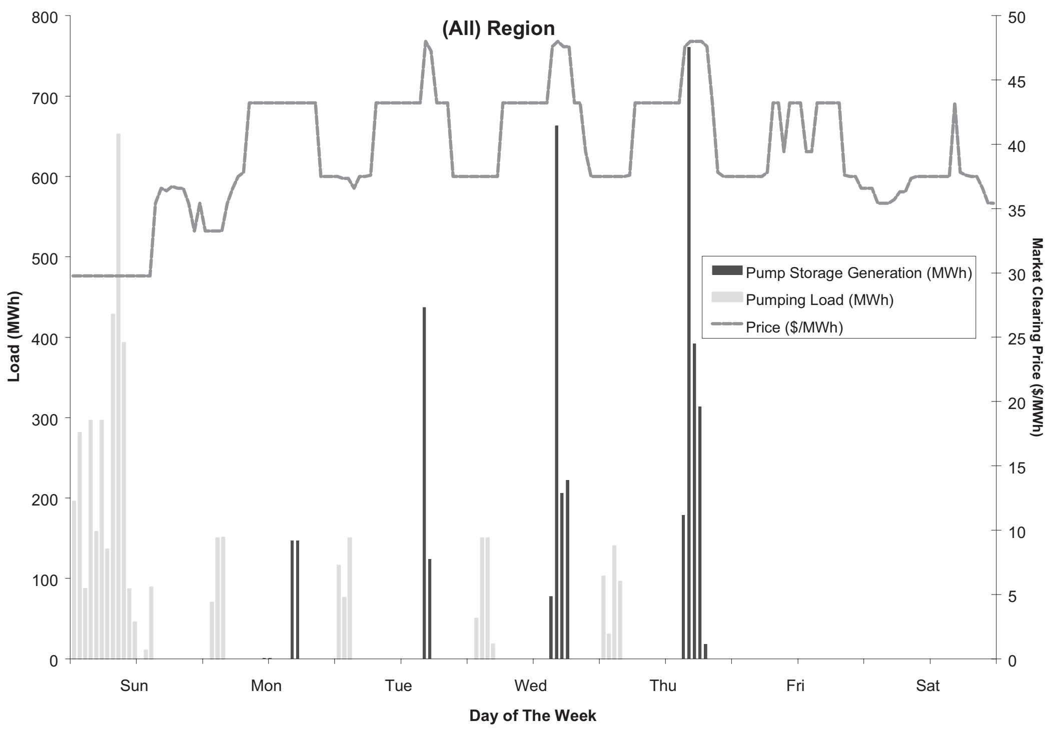

FIG. 61. Pumped storage operations in GTMax as driven by market prices[6].

6 Actual operations may differ due to the need for northern region voltage control at night.

4.3.4. Regional operations

As described previously in more detail each dispatch region in Poland has its own unique characteristics in terms of load levels and generation supply resources. While some regions have high load factors others have a supply deficit. Also, production costs vary significantly among regions. The regional supply and demand balance along with the regional marginal cost production differences leads to unique operational characteristics in each region.

4.3.4.1. Central region

Figure 62 shows loads and generation levels in the Central region for the peak week of the year. This region is characterised by high reserve margins and low variable production costs. Fuel is relatively inexpensive in this region. As shown in the figure hourly generation is significantly higher than loads. The vast majority of the energy production is from thermal power and CHP plants. Run-of-river hydro production is very small. In addition, total regional generation levels are almost constant during the week with only slightly lower production levels during Sunday. The excess generation is exported to other regions that have supply deficits or higher costs.

Figure 63 shows export levels from the Central region for the peak load day (Thursday). Export of power range from about 900 MW·h during the peak load hour to over 1760 MW·h at 3 am in the morning. Note that exports follow a pattern that is directly opposite that of Central regional loads. At night when loads are low the region exports relatively higher levels since less energy is needed to meet its own demands. The reverse occurs during the daytime.

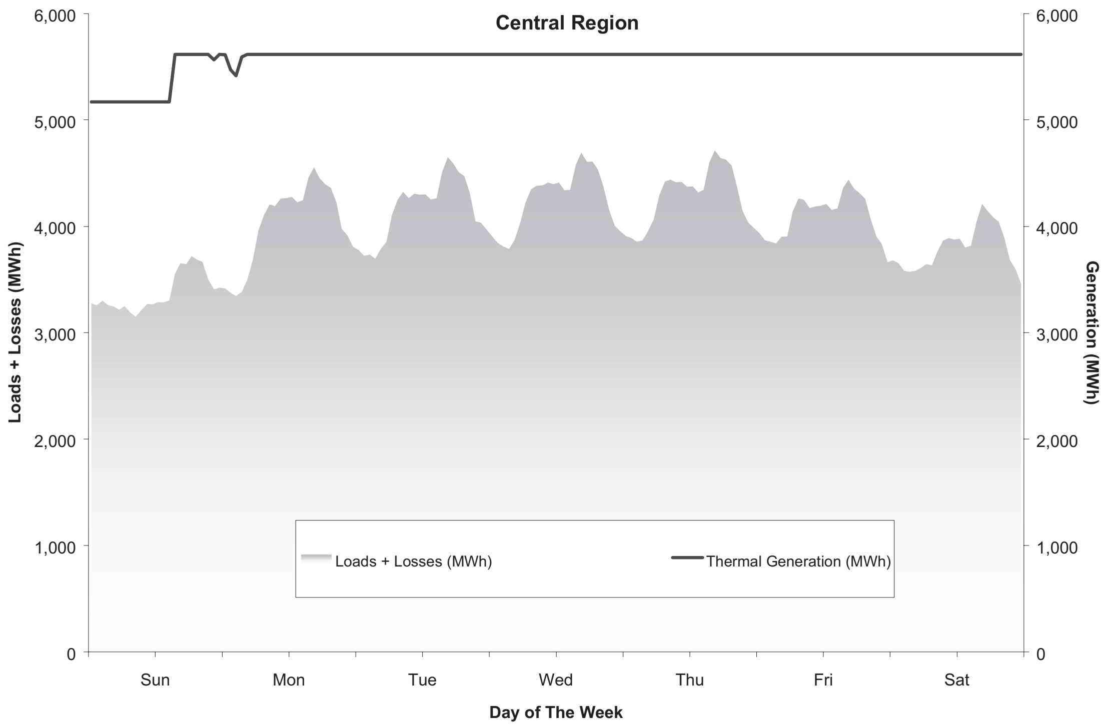

FIG. 62. Generation and loads in the Cenrtal Region during the peak load week.

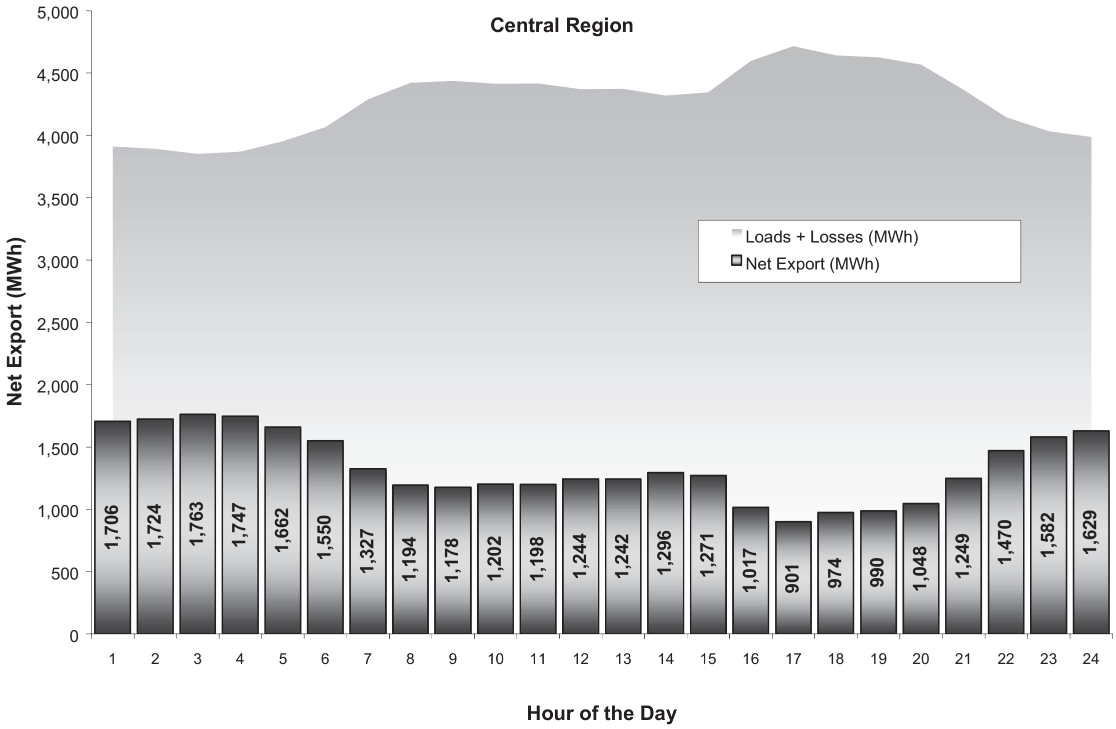

FIG. 63. Power exports/sales from the Central Region during the peak load day.

4.3.4.2. Northern Region

Much of the excess energy production from the Central region is transfer and sold to the Northern region that is characterised by negative reserve margins and higher variable production costs. Figure 64 shows that electricity demand in the North are much higher than the combined generation from run-of-river hydropower, thermal, CHP and pumped storage power plants. Operations of the CHP and thermal power plants are nearly constant during the week with slightly higher production levels during the daytime.

Energy import levels by the Northern region are shown in Fig. 65 for the peak load day. Import of power range from slightly less than 1850 MW·h during an early morning hour to 2268 MW·h. The import pattern closely follows the loads most of the time. However, when generation from the pumped storage power plants occurs the import levels decline.

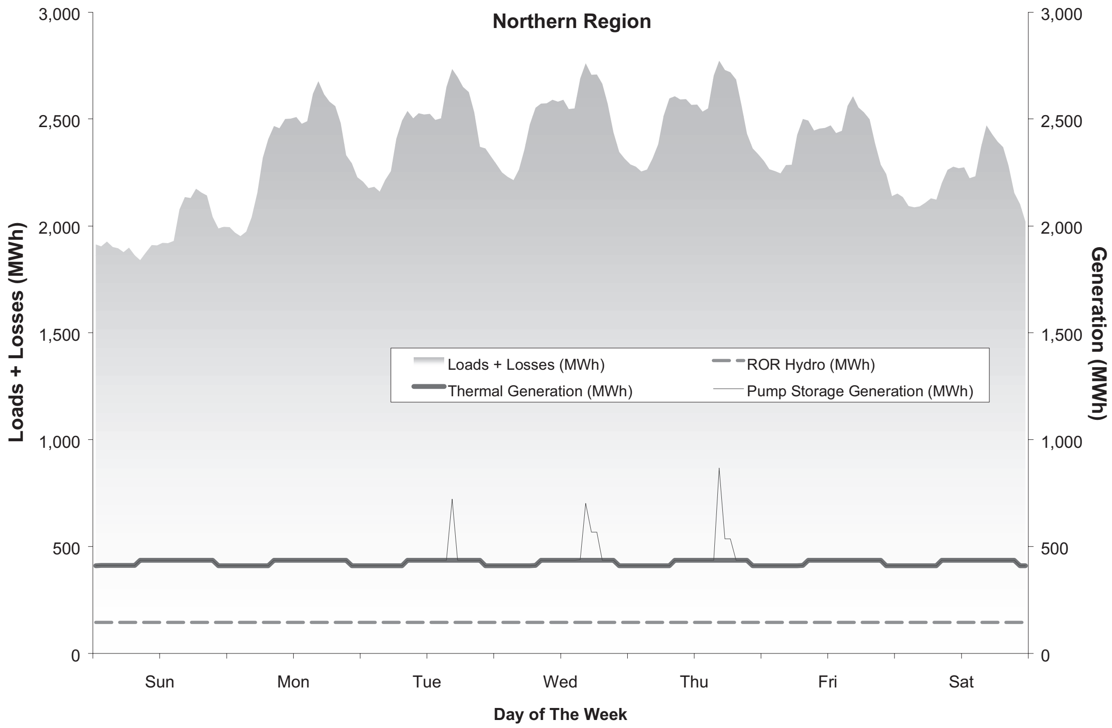

FIG. 64. Generation and loads in the Nothern Region (peak load week).

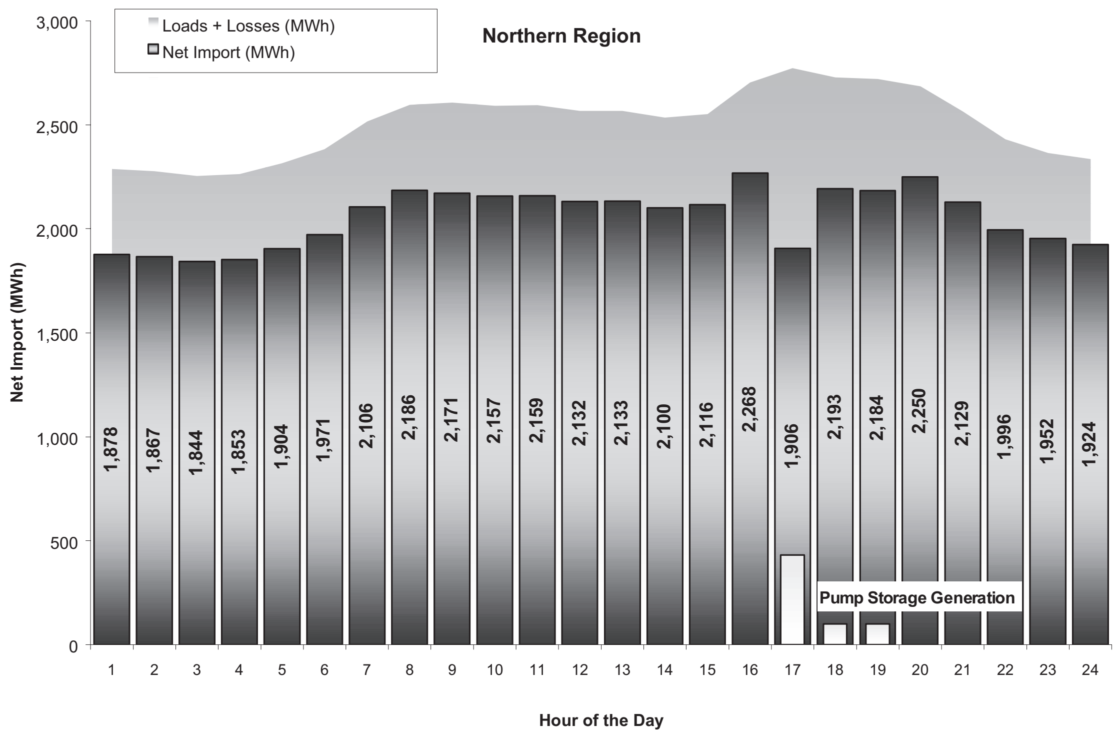

FIG. 65. Power imports/purchases by the Northern Region (peak load day).

4.3.4.3. Southern Region

The Southern region differs from both the Northern and Central regions in that generation patterns follow loads more closely. As shown on Fig. 66, thermal power plant generation in the region tends to follow loads with generation levels that exceed regional loads during some peak load hours. During the night and some shoulder hours, thermal generation is slightly lower than loads. Note that generation from storage hydro power plants occurs during the highest load hours and is exported to serve loads elsewhere in the grid.

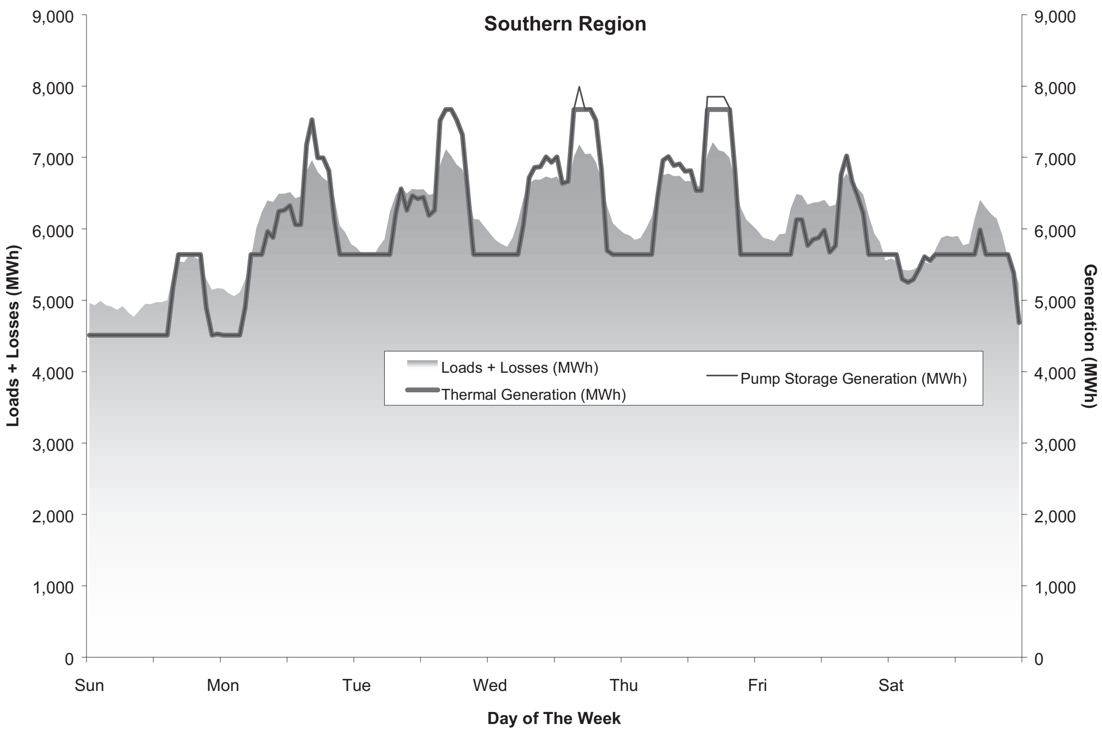

FIG. 66. Generation and loads in the Southern Region (peak load week).

There are relatively small amounts of power that are at times exported from the region and during other times energy is imported into the region. As shown in Fig. 67 for the peak load day, energy is imported into the region during low load hours and exported during on-peak hours. Generation from pumped storage power plants aids in the region’s capacity to export power during peak hours. Selling energy at high prices during the day and buying energy during the night adds to the net revenues of the region. Both imports and exports are below 1000 MW·h and are relatively small compared to total loads and generation resources.

4.3.4.4. Eastern region

Similar to the Southern region, the generation pattern tends to follow lows in the Eastern region. However, as shown on Fig. 68, the region has generation levels that are higher than loads in the region during all weekday hours and during peak hours on Saturday. Generation from storage hydro power plants occurs during the highest load hours and is exported to serve electricity demands elsewhere in the grid. Generation levels dip below loads during Sunday and off-peak hours on Saturday. As shown in Fig. 69, power exports occur during all hours of the highest load day ranging from about 215 MW·h to 730 MW·h.

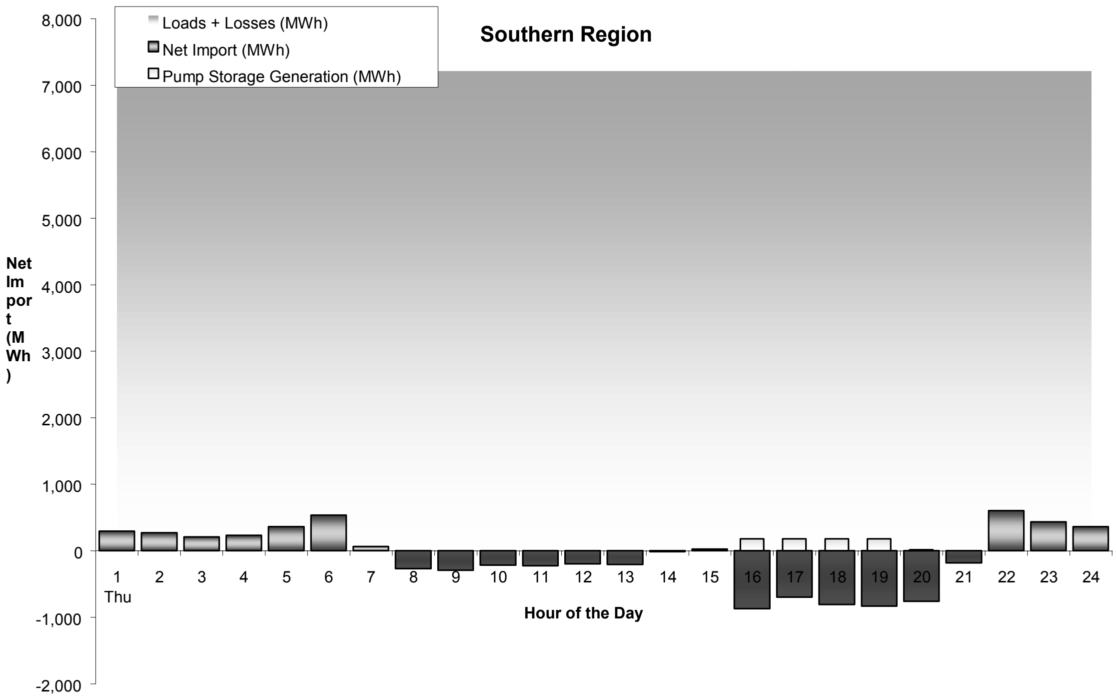

FIG. 67. Power imports and exports in the Southern Region (peak load day).

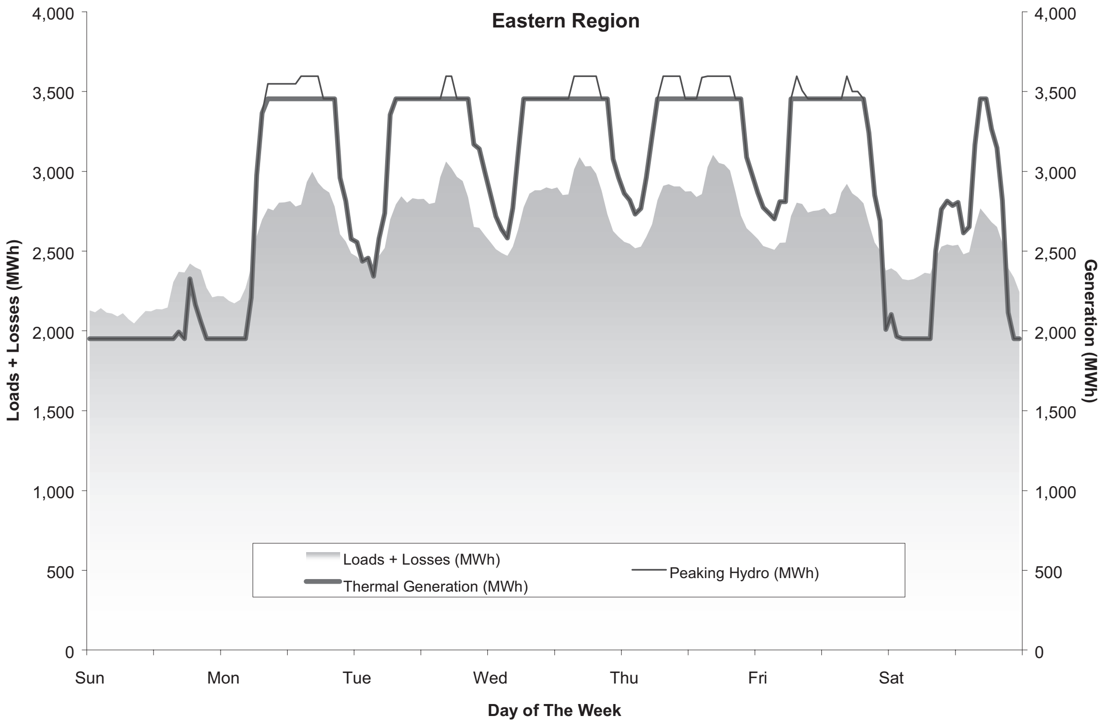

FIG. 68. Generation and loads in the Eastern region (peak load week).

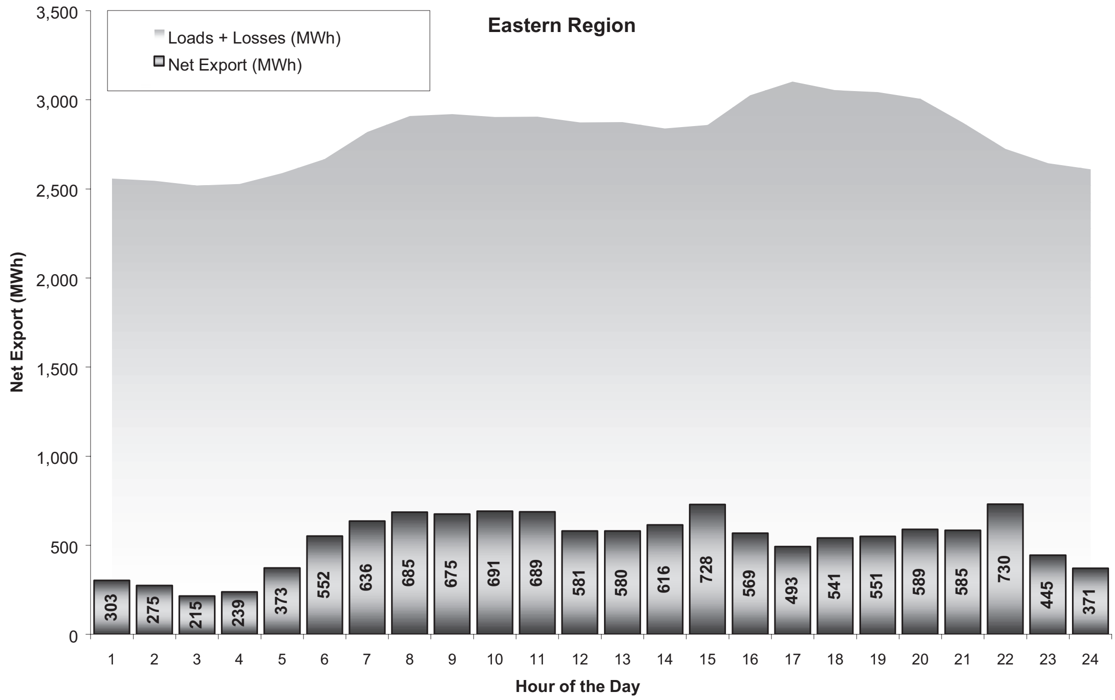

FIG. 69. Power exports/sales for in the Eastern region (peak load day).

4.3.4.5. Western region

Generation in the Western region, also tends to follow loads plus sales but the range of generation is less than the range in loads. As shown in Fig. 70, generation levels during the night are higher than the loads/sales while loads/sales and generation levels are nearly identical during the weekday peak. Net exports shown in Fig. 71 show that exports and imports for the peak load day are small compared to the loads and resources.

4.3.5. Small-scale gas-fired CHP analysis

Revenues for a candidate CHP power plant were estimated by the peak load week. This plant is a small local CHP facility with a generation capability for 24 MW. The candidate plant was assumed to be located in the Northern region since this part of Poland is estimated by GTMax to have the highest marginal value of energy. Since the CHP was assumed to be located very near a load centre losses would be negligible.

The generation pattern projected by GTMax and the estimated prices for energy are shown in Fig. 72. Prices delivered to the 15 kV system are higher than prices at the market hub which are on the high voltage transmission system. Therefore, the prices of energy shown on Fig. 72 are higher than the average market hub price displayed in previous figures.

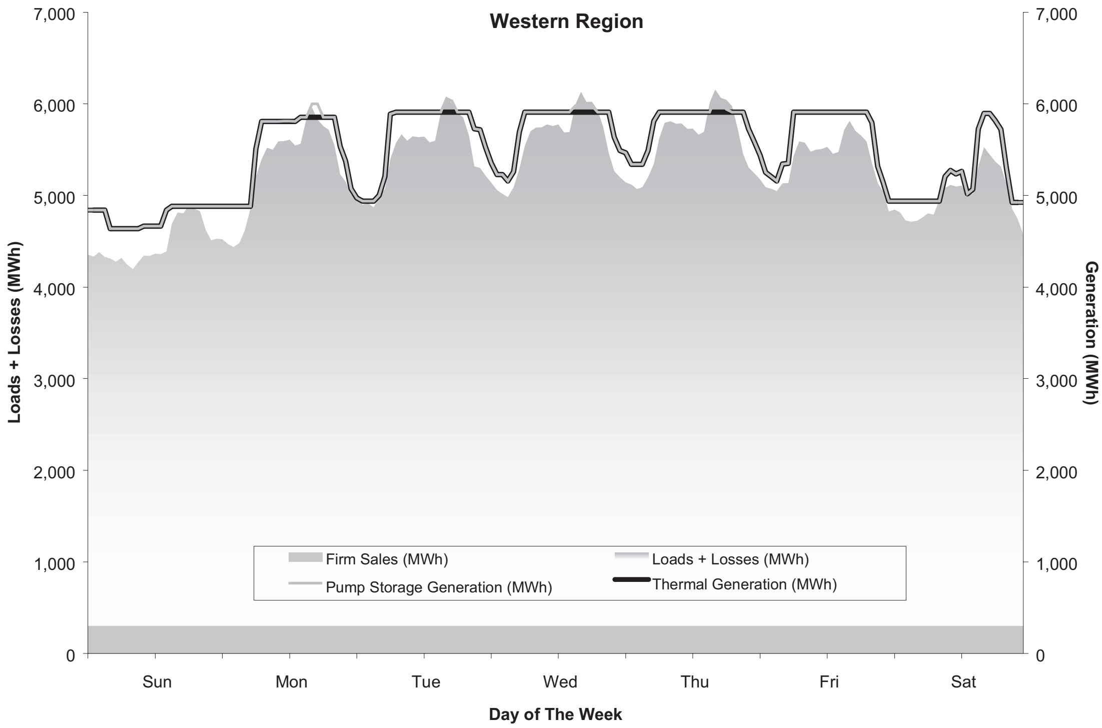

FIG. 70. Generation and loads in the Western region (peak load week).

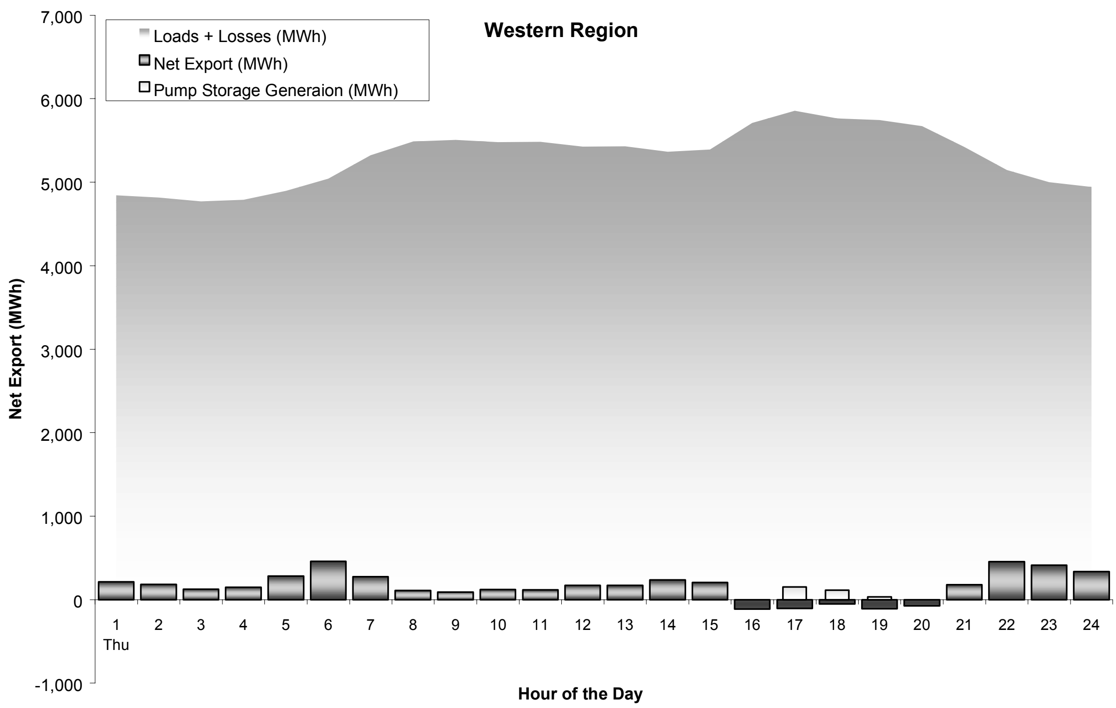

FIG. 71. Power exports/sales for in the Western region (peak load day).

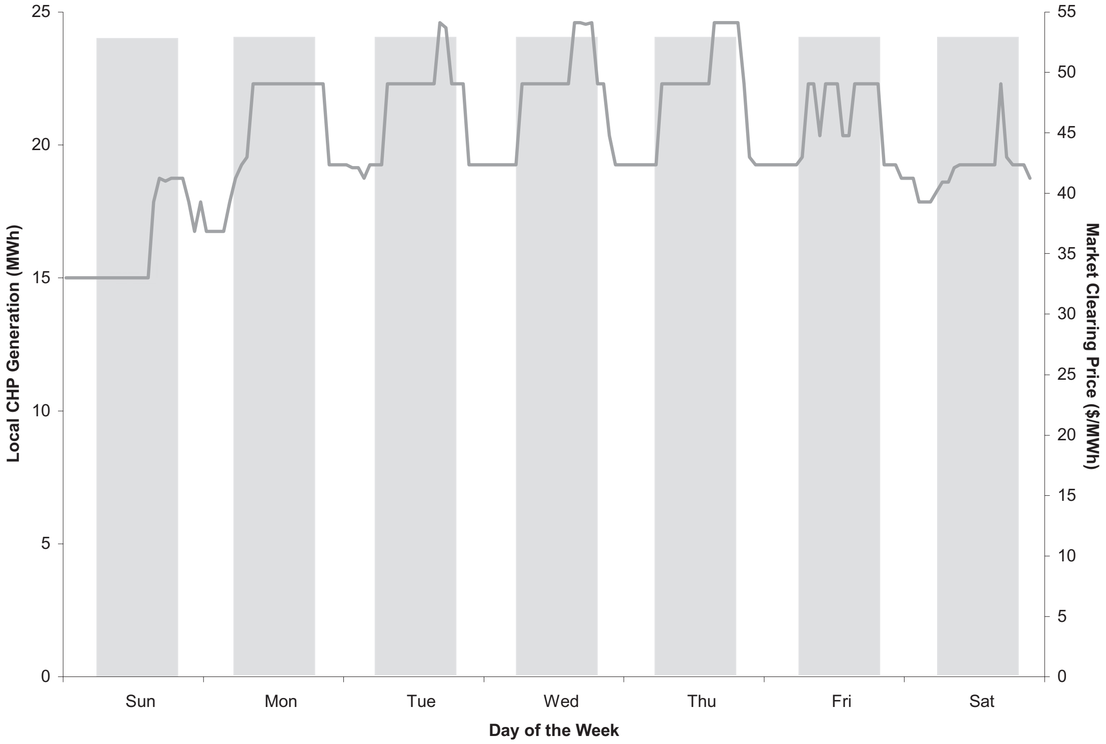

FIG. 72. CHP Power plant generation and delivered energy prices.

The CHP power plant generates electricity at full capacity for 14 hours per day from 9 am to 10 pm. This generation pattern is projected for all 7 days during the simulated week. The amount of money that owners of the CHP plant would receive is assumed to be the hourly market price of energy multiplied by the amount of energy sold in the hour. However, a payment tariff structure was established for energy sales. Based on an earlier study conducted by EMA the average payment that would be received by CHP owners is about 43.25 \$/MW·h. This is somewhat lower than the average price that is estimated by the GTMax model for the peak load week of the year.

Table 37 shows the estimated revenues and incremental production costs for owners of a CHP facility. Incremental production costs are estimated to be between 6 to 10 \$/MW·h. This is the cost difference between operating the plant for only heat production and for generating both heat and electricity. The CHP operational expenses of \$23530 shown in the table is based on a 10 \$/MW·h incremental production cost. Revenues or the amount owner would receive during the peak load week is about \$109.340. The difference or short-term net revenue is about \$86 000. When an incremental cost of 6 \$/MW·h is assumed the net revenue increases to more than \$95 000. Over the lifetime of the project, these net short-term revenues must be large enough to pay for all fixed expenses plus capital expenses. Although a company may have positive short-term net revenues, in the long-term the company may become bankrupt. This problem was not analyzed with GTMax.

The average payment for energy is about 47.11 \$/MW·h. This is somewhat higher than the 43.25 \$/MW·h estimated by EMA in its previous study. However, GTMax prices for other weeks of the year would most likely be lower for non-peak weeks in the year.

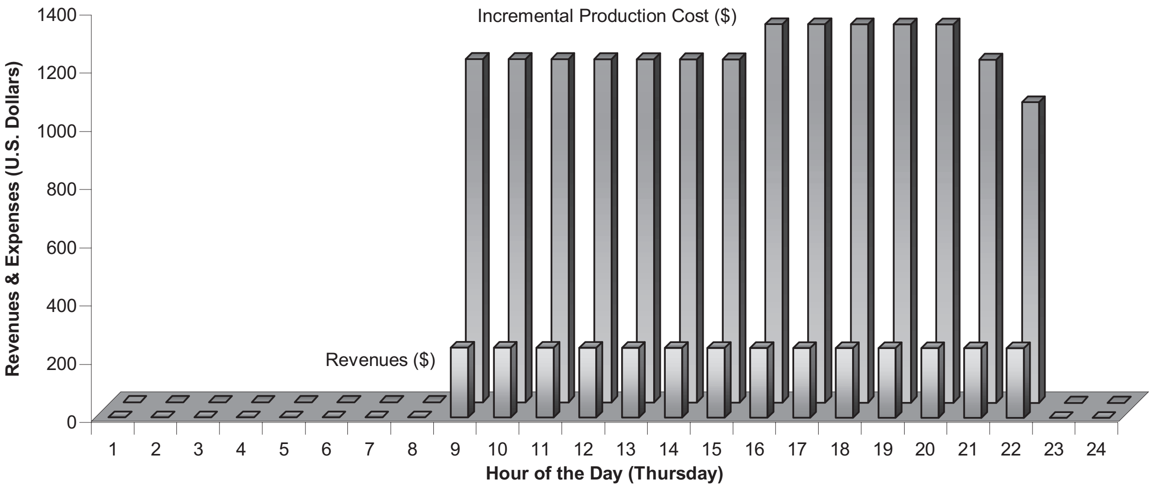

FIG. 73. Revenues and expenses for owners of CHP power plants.

TABLE 37. GTMax estimates of net revenues from CHP electricity sales

Day	Revenues ($)	Incremental Cost ($)	Net Revenues ($)
Sun	12,374	3,360	9,014
Mon	16,323	3,360	12,963
Tue	16,555	3,360	13,195
Wed	16,908	3,369	13,539
Thu	16,946	3,360	13,586
Fri	15,858	3,361	12,497
Sat	14,375	3,360	11,015
Grand Total	109,340	23,530	85,810

4.3.6. Transactions East–West analysis

In order to represent East to West international power transmission, two additional nodes, shown in Fig. 51, were created: one injection node of firm purchases (RU) from Russia and a sink node of firm sales (GE) to Germany. The objective of this representation was to determine:

— maximum power to be transferred in the framework of the "East–West Bridge" by the existing Polish Transmission Grid;
— wheeling cost of the power transmission.

To that goal a number of simulations were performed for the 24th week (June) and 48th week (December).

The wheeling costs curve was determined by setting increasing transmission power. These costs include two factors: additional transmission costs caused by the transactions and costs due to distortions in optimal power dispatch. Wheeling costs are presented in Fig. 74.

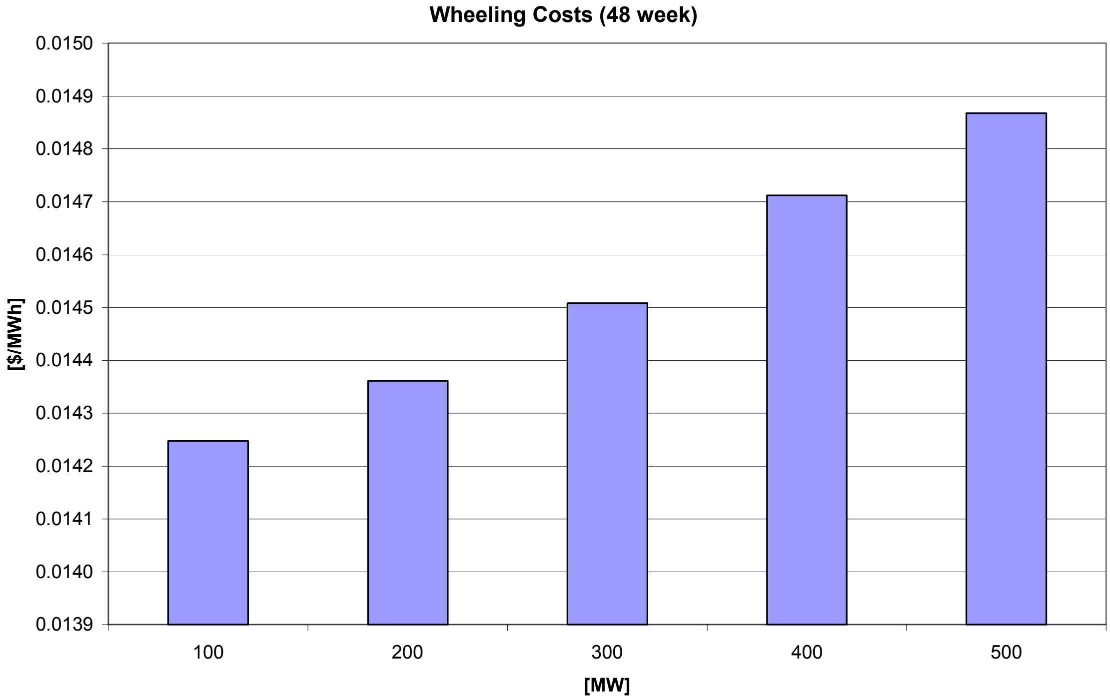

FIG. 74. Wheeling costs of the East-West transmission through existing grid.

In order to obtain a rough estimate of contractual power transfers across Poland, available transmission capabilities (ATC) were calculated. The GTMax model bases these computations on the total transfer capability (TTC) that is input into the model minus contractual energy flows computed by GTMAx. Results for ATC over user-defined paths are provided in Fig. 75. Estimated values are relatively small for the Northern path while the central path has the highest values that at times exceed 2000 MW. The northern path is often at or near its defined transmission transfer capability since the Northern region has a supply shortage that is satisfied via less expensive production for the western and eastern regions.

4.4. Conclusions

This analysis, implemented with the GTMax model, was limited due to the lack of time. Nevertheless, short-term electricity flows in the Polish grid were modelled successfully with an accurate representation of the five interconnected regions comprising the grid.

Three tasks were solved with GTMax:

- assessment of short-term revenues for a small (24 MW) gas-fired CHP;
- estimation of the maximum power that could be transferred in the framework of the "East-West Bridge" by the existing Polish Transmission Grid;
- determination of the wheeling cost of the power transmission through the Polish grid.

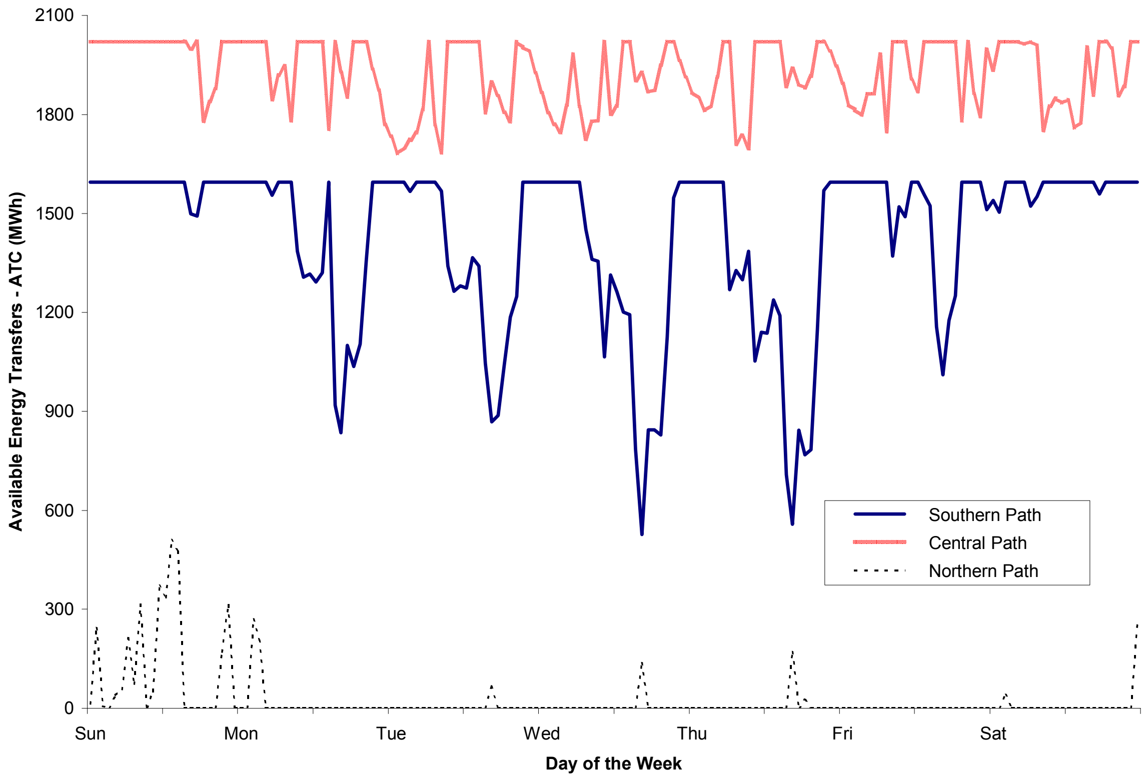

FIG. 75. Computed ATC values for three paths across the Polish power system.

The analysis has shown the following:

— The incremental production costs for the CHP facility are estimated to be between 6 to 10 \$/MW·h. This is the cost difference between operating the plant for only heat production and for generating both heat and electricity. Per year, the difference or short-term net revenue is about US \$90 000. Over the lifetime of the project, these net short-term revenues must be large enough to pay for all fixed expenses plus capital expenses. (Although a company may have positive short-term net revenues, in the long-term it may become bankrupt – this problem was not included in the GTMax analysis.)

— The available transmission capabilities (ATC) of the Polish grid for the "East-West Bridge" varies between zero (if the Northern path is used) and some 2000 MW (for the Central path). The northern path is often at or near its defined transmission transfer capability since the Northern region has a supply shortage that is satisfied via less expensive production for the Western and Eastern regions. In contrast, the ATC of both the Southern and the Central path is relatively high — between 600 and 2000 MW.

— The wheeling costs curve was determined by setting increasing transmission power. These costs include additional transmission costs caused by the transactions and costs due to distortions in the optimal power dispatch. The costs vary between 1.42 and 1.49 cent/MW·h.

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ABBREVIATIONS

ARE S.A.	Energy Market Agency (the Polish abbreviation)
ATC	available transmission capabilities
BOE, boe	barrel of oil equivalent
CC	combined cycle
CCGT	combined cycle gas turbine plant
CHP	combined heat and power
DC	direct current
EC	European Commission
EdF	Electricité de France
EMA	Energy Market Agency
ENPEP	Energy and Power Evaluation Program
FED	final energy demand
FEWE	Polish Foundation of Energy Efficiency
FGD	flue gas desulphurisation
GDP	gross domestic product
GHG	greenhouse gas
GIS	Geographical Information System
GT	gas turbine
GTMax	Generation and Transmission Maximization Model
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
IPP	Independent Power Producers
IRiSS	Institute of Development and Strategic Studies
LP	linear programming
O&M	operation and maintenance
PED	primary energy demand
PFBC	pressurised fluidised bed combustion
PPGC	Polish Power Grid Company
PSE SA	Polskie Sieci Elektroenergetyczne
TC	technical co-operation
TFC	total final consumption
TPES	total primary energy supply
TTC	total transfer capability

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